THE STATE OF SOUTH CAROLINA
In the Supreme Court

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APPEAL FROM THE PUBLIC SERVICE COMMISSION

Appellate Case No. 2018-001165 and 2018-002117

Commission Docket No. 2018-2-E

South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, Appellants,

v.

South Carolina Electric & Gas, CMC Steel South Carolina, South Carolina Energy Users Committee, South Carolina Solar Business Alliance, LLC, Southern Current, LLC and South Carolina Office of Regulatory Staff, Respondents;

and

South Carolina Solar Business Alliance, LLC, Appellant,

v.

South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, South Carolina Electric and Gas, CMC Steel South Carolina, South Carolina Energy Users Committee, Southern Current, LLC, and South Carolina Office of Regulatory Staff,

Of whom South Carolina Electric & Gas and South Carolina Office of Regulatory Staff, are Respondents.

RECORD ON APPEAL
Volume IV of IV

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The correction noted herein reflects the testimony given during the hearing in this matter.

DIRECT TESTIMONY OF

Dr. Ben Johnson

ON BEHALF OF THE

SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

Before the

PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2018-2-E

Introduction

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida. I am a Consulting Economist and President of Ben Johnson Associates, Inc., a consulting firm that specializes in public utility regulation.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. I have been retained by the South Carolina Solar Business Alliance, LLC ("SBA") to assist in preparing and presenting evidence in this proceeding with respect to the Public

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Utility Regulatory Policies Act of 1978 ("PURPA"), the avoided costs of South Carolina Electric & Gas ("SCE&G" or "the Company") and proposed changes to Rate PR-2. Members of SBA include Independent Power Producers that sell the output of their facilities to incumbent utilities like Duke Energy and SCE&G in the generation of electricity under PURPA. These firms are planning to invest (or are already in the process of investing) more than $5 Billion in the development of solar generating facilities in the state of South Carolina over the next 3 to 4 years.[1] Depending on the economic success or failure of these initial investments, the extent of future needs for generation, and the state's regulatory and competitive climate, these firms are likely to make additional investments in future years. Needless to say, with billions of investment dollars at stake, the SBA members are vitally interested in the PURPA related issues in this proceeding.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. The earliest case I can recall was Docket No. 77-354-E which was a 1978 case involving Carolina Power & Light Company. I've worked in several other South Carolina proceedings since that time, involving electric, telephone and water utilities. The most recent case was Docket No. 2017-2-E.

Q. CAN YOU PLEASE BRIEFLY DESCRIBE YOUR OTHER QUALIFICATIONS?

[1] Allowable Ex Parte Briefing No-2018-5-E, March 14, 2018 Transcript, Page 56.

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A. Yes. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics.

I have been actively involved in public utility regulation since 1974. Over the past four decades I've been involved in many different types of regulatory proceedings. This work has encompassed an unusually broad range of issues – from setting the appropriate rate of return, to the appropriate items to allow or disallow in the rate base, to weather normalization adjustments, to integrated resource planning, to the allocation of costs across jurisdictions and customer classes, to in-depth prudence reviews related to two nuclear plants (the South Texas Project, where I worked on behalf of a large group of municipalities, and the Shearon Harris plant, where I worked on behalf of the Public Staff of the North Carolina Public Utilities Commission). I also have extensive experience working in proceedings related to competitive entry into industries that have historically been organized around vertically integrated monopolies, including many different proceedings involving the implementation of PURPA, beginning with Docket No. 14 E-100, Sub 53, a 1986 North Carolina proceeding concerning avoided costs.

All told, I have participated in more than 400 regulatory dockets over the course of my career, and I've provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian provinces,

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and the District of Columbia. Most of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation, but members of my firm and I have worked for other clients, including large industrial customers, non-profit organizations like the AARP, and independent power producers.

Q. HAVE YOU PREPARED AN APPENDIX THAT PROVIDES SOME ADDITIONAL DETAILS CONCERNING YOUR QUALIFICATIONS?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following this introduction, I first provide some rate comparisons. Second, I discuss various aspects of PURPA from my perspective as an economist. Third, I discuss some methodologies that can be used to estimate avoided costs. Fourth, I discuss the Company's avoided energy costs. Fifth, I discuss the Company's proposed QF related tariff changes, including its proposal to reduce its QF capacity rates to zero, and to reduce solar rates below those paid to non-solar QF's. In this section I note the major changes the Company is proposing to its methods and inputs for calculating avoided cost, which would have the effect of sending less precise price signals to independent power producers and discouraging QF investment. I also explain why stronger, more accurate QF price signals are needed. Sixth, I provide estimates of long run avoided capacity

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costs which can be useful in setting capacity rates. Finally, I provide my recommendations for what action the Commission should take in this proceeding.

Rate Comparisons

Q. CAN YOU BRIEFLY DESCRIBE THE CURRENT AND PROPOSED RATES PAID TO QUALIFYING FACILITIES?

A. Yes. Under PURPA, electric utilities are required to purchase energy and capacity from certain independent power producers, provided they build and operate relatively small generating plants with a capacity equal to or less than 80 MW, and provided they use certain designated technologies. Firms that meet specific standards set forth in the applicable federal regulations are called Qualified Facilities (QF's), and they are allowed to connect these facilities to the grid, in competition with the generating units in the incumbent utility's rate base.

QF's are paid for the electricity they produce based on negotiated rates, or rates that are set by the state regulatory commission, consistent with regulations established by the Federal Energy Regulatory Commission (FERC). The current SCE&G QF tariffs were approved by the Commission in Docket 2017-2-E on April 19, 2017. The current tariff sets forth a single set of rates applicable to all types of QF's, with variations depending on the timing of when the power is provided by the QF. More specifically, the current (and

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proposed) SCE&G tariffs provide separate rates for 5 year blocks. The currently approved rates are for the years 2017 – 2021, 2022 – 2026 and 2027 – 2031, while the proposed rates are for the years 2018 – 2022, 2023 – 2027 and 2028 – 2032. This tariff structure apparently gives QF's the option of contracting to sell capacity and energy for up to 15 years, with the QF being paid different rates during each 5 year period.

Under both the current and proposed tariffs, QF's are paid higher rates during the summer, and lower rates during the rest of the year. There is also a difference related to the time when the electricity is injected into the grid, with higher rates paid during on-peak hours and lower rates during off-peak hours and on holidays and weekends.

Unlike the current tariff, the tariff proposed that is being reviewed in this proceeding segregates solar QF's from other power providers, and the SBA members will presumably be paid less for their electricity than the rates that will be paid to other qualified technologies under PURPA, like biomass, wind and hydro.

Q. PRIOR TO RECEIVING THE NEW TARIFF FILING, WHAT CHANGES DID YOU EXPECT TO SEE IN SCE&G'S PROPOSED ENERGY RATES?

A. I expected to see a small degree of upward movement. This follows logically because the energy rates are closely tied to natural gas and fuel prices, and those prices (and projections of future price levels) have not changed greatly over the past year, aside from

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the impact of another year of inflation. However, I was also expecting an increase in the avoided cost of energy due to the cancellation of the V.C. Summer nuclear units. While the nuclear units were going to be very costly on an "all-in" basis, including the enormous cost of building these units, the units were also expected to be operated at nearly full capacity on a year-round basis, with very low variable costs. This influx of nuclear energy was expected to displace energy produced by coal and natural-gas fired units which have higher variable costs. Once the nuclear units were canceled, the logical consequence would be to reverse (or eliminate) these effects, causing the existing coal and gas units to operate longer hours, along with larger purchased power costs with higher variable costs than the nuclear units. The end result should have been an increase in the QF energy rates. Without the very high capital costs associated with the nuclear units, the net result would likely be lower rates paid by retail customers – despite paying slightly higher rates to QF's.

Q. BEFORE YOU SAW THE NEW TARIFF FILING, WHAT CHANGES WERE YOU EXPECTING TO SEE WITH RESPECT TO QF CAPACITY RATES?

A. I expected to see a significant increase in the Company's QF capacity rate, bringing it close to the QF rates approved by this Commission for Duke Energy Carolinas (1.242 cents per kWh) and Duke Energy Progress (1.321 cents per kWh). This expectation logically followed from the fact that the nuclear units had recently been canceled, and

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those units were previously expected to meet all of the Company's need for capacity in the near future (and arguably create a degree of excess capacity). It is my understanding that the existence of those units was the primary factor explaining why SCE&G proposed such low capacity rates in Docket No. 2017-2-E (as little as 0.149 cents per kWh).

In the previous fuel case (Docket No. 2017-2-E), the Company essentially argued that the costs of the nuclear units were not avoidable, and that it had contractual commitments to purchase firm power that would meet all of its capacity needs until the nuclear units were scheduled for completion. In effect, the Company contended that it had no ability to "avoid" capacity costs, which seemed to be the primary justification for paying nothing to QF's for their capacity in most years. Once the nuclear units were canceled, this rationale disappeared, and so I expected that applying the same logic, assumptions and methodology would translate into significantly higher capacity rates.

Q. HAVE YOU COMPARED THE QF RATES PROPOSED IN THIS CASE TO ANALOGOUS RATES APPROVED IN THE LAST PROCEEDING?

A. Yes. I compared the rates on a composite or weighted average basis, as they apply to a typical solar facility. More specifically, I looked at the rates that are currently applicable during each hour of each day of the year, and applied them to the volume of energy which can reasonably be expected from a typical QF solar facility, to estimate the total

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payments that would be received by the QF. The total payments were then divided by the total kWh which were expected to be produced by the QF, in order to calculate an overall composite rate per kWh. This procedure took into account how the Summer and Non-Summer seasons are defined, as well as how the peak and non-peak time periods are defined in the current tariff. Most of the energy produced by solar QF's qualifies for the on-peak rate – with the exception of weekends, when the lower off-peak rate applies regardless of the time of day.

The results of this comparison are shown below for the first five year time period:

Difference in SCE&G Rates paid to QF's:
Current 2017-2021 versus Proposed 2018-2022 (prices per kWh)

	Energy	Capacity	Total
Current Tariff	3.253 cents	0.153 cents	3.406 cents
Proposed Tariff	2.853 cents	0.000 cents	2.853 cents
Difference	-0.400 cents	-0.153 cents	-0.553 cents
Percent Difference	-12.3%	-100.0 %	-16.2 %

This table shows a similar comparison for the next five year period:

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Difference in SCE&G Rates paid to QF's: Current 2022-2026 versus Proposed 2023-2027 (prices per kWh)			
	Energy	Capacity	Total
Current Tariff	3.054 cents	0.153 cents	3.207 cents
Proposed Tariff	2.994 cents	0.000 cents	2.994 cents
Difference	-0.060 cents	-0.153 cents	-0.213 cents
Percent Difference	-2.0%	-100.0 %	-6.6 %

This table shows a similar comparison for the final five year period:

Difference in SCE&G Rates paid to QF's: Current 2022-2026 versus Proposed 2023-2027 (prices per kWh)			
	Energy	Capacity	Total
Current Tariff	3.383 cents	0.153 cents	3.536 cents
Proposed Tariff	3.414 cents	0.000 cents	3.414 cents
Difference	+ 0.031 cents	-0.153 cents	-0.122 cents
Percent Difference	+ 0.9%	-100.0 %	-3.5 %

In all years, SCE&G is proposing to reduce payments to QF's. The largest percentage reduction occurs in the initial five year period (which happens to be the one with the greatest negative impact on the Net Present Value of a QF investment). In contrast, if the Company had simply updated its input assumptions to reflect changes in fuel prices and

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economic conditions, taking into account the cancellation of the nuclear units and applying the methodology previously approved by the Commission in the same manner as it had in the past, SCE&G would have calculated higher QF rates – not lower rates.

PURPA

Q. CAN YOU PLEASE EXPLAIN YOUR UNDERSTANDING OF THE FEDERAL STANDARDS WHICH APPLY TO QF RATES?

A. Yes. As I alluded to previously, in 1978, Congress established a special class of generating facilities known as "Qualifying Facilities."[2] Under PURPA, electric utilities are required to purchase electrical energy from Qualifying Facilities ("QF's") at rates which must not discriminate against the firms that operate these facilities. More specifically, PURPA requires the Federal Energy Regulatory Commission ("FERC") to prescribe rules necessary to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity."[3] State commissions have an important role in implementing PURPA, together with FERC and the courts. Questions about the actual avoided-cost determinations are litigated before the state commissions or the state courts with applicable jurisdiction for non-regulated utilities. Questions regarding whether a method of avoided-cost

[2] 16 U.S.C. § 824a-3.

[3] 16 U.S.C. § 824a-3(a).

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determination is consistent with PURPA and FERC implementation rules are litigated before FERC or an applicable federal court.[4]

State commissions have been provided with extensive guidance for how they are to carry out their responsibilities, both in the text of the underlying statute, and in rules adopted by FERC which were subsequently upheld by the United States Supreme Court.[5] For instance, rates for purchases from QF's ("QF rates") must: a) be just and reasonable to the electric consumers of the electric utility and in the public interest; b) not discriminate against qualifying cogenerators or qualifying small power producers; and c) cannot exceed "the incremental cost to the electric utility of alternative electric energy."[6]

While I am not an attorney, it is my understanding as an economist that under PURPA the Commission is expected to (1) require utilities to purchase energy and capacity from QF's on terms consistent with all applicable FERC regulations; (2) treat avoided costs as the pricing floor for those purchases; (3) enforce the legal right for QF's to sell power to utilities on either an as-available basis, or pursuant to a "Legally Enforceable Obligation" at the QF's option; (4) enforce the legal right for QF's to sell power to utilities pursuant

[4] PURPA Title II Compliance Manual, Page 15. The PURPA Title II Compliance Manual was jointly published by the American Public Power Association (APPA), Edison Electric Institute (EEI), National Association of Regulatory Commissioners (NARUC) and National Rural Electric Cooperative Association (NRECA) on March 2014, with the intended purpose of being used as an aid to state commissions and utilities as they deal with issues related to PURPA.

[5] *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 103 S. Ct. 1921 (1983).

[6] 16 U.S.C. § 824a-3(a).

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to long-term contracts; (5) ensure utilities provide nondiscriminatory interconnection and/or transmission service to QF's that they sell power to QF's on request.

Q. CAN YOU EXPLAIN THE "INDIFFERENCE" STANDARD AND THE "AVOIDED COST" CONCEPT?

A. Yes. As the FERC has stated on several occasions, the intention of Congress in enacting PURPA "was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives" of PURPA.[7] As explained more recently by the North Carolina Utilities Commission, "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."[8] Although PURPA is designed to encourage QF development, it does not accomplish this by subsidizing QF's, or by requiring customers to pay more for their power. To the contrary, if PURPA is correctly implemented, ratepayers are "held harmless," leaving them indifferent to whether they receive power from a QF or from new generating units added to the utility's rate base.

FERC recently confirmed that ratepayers should be "financially indifferent" when QF rates are appropriately set, and it went further by rejecting arguments that financial indifference must be narrowly defined, to exclude consideration of "societal and

[7] *Southern Cal. Edison, San Diego Gas & Elec.*, 71 FERC ¶ 61,269 at p. 62,080 (1995).

[8] North Carolina Utilities Commission, December 31, 2014 Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, Page 21.

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environmental benefits."[9]

The FERC rules implementing PURPA generally require electric utilities to purchase any energy and capacity which is made available to the utility from a Qualifying Facility.[10] Rates for purchases from Qualifying Facilities built after 1978 must be based upon the electric utility's "avoided costs."[11] FERC defines avoided costs as:

> [T]he incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[12]

Among other things, the FERC rules require state commissions, to the extent practicable, to consider these factors when determining avoided costs:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> (i) The ability of the utility to dispatch the qualifying facility;
>
> (ii) The expected or demonstrated reliability of the qualifying facility;
>
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

9 FERC, Order Denying Rehearing, Docket No. EL 10-06-002, January 20, 2011, Paragraph 16.

10 18 C.F.R. § 292.303(a).

11 18 C.F.R. § 292.101(b).

12 18 C.F.R. § 292.101(b)(6).

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(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.[13]

Q. CAN YOU EXPLAIN WHAT INFORMATION IS REQUIRED BY SECTION 292.302(B) OF THE FEDERAL CODE OF REGULATIONS?

A. Yes. Under FERC PURPA regulations, utilities like SCE&G are required not less often than every two years to provide to their state regulatory commission the following information, and to make it available for public inspection:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases

[13] 18 C.F.R. § 292.304(e).

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from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.[14]

SCE&G generally submits this information to the Commission in June of even-numbered years – most recently in June 2014 and June 2016.

Q. CAN YOU EXPLAIN YOUR UNDERSTANDING OF WHY THIS INFORMATION HAS TO BE PUBLICLY AVAILABLE, WHY THE "INDIFFERENCE" AND "AVOIDED COST" REQUIREMENTS WERE IMPOSED, AND WHAT THESE ASPECTS OF PURPA ACCOMPLISHED?

A. Yes. Looking at the relevant portions of PURPA from my perspective as an economist, it appears to advance at least two distinct goals: First, it encourages expanded use of targeted technologies and energy sources which had been neglected by the electric utility

[14] 18 U.S.C. § 292.302(b).

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industry. Second, it encourages investment in small power producers – new firms that enter the market to develop these targeted technologies and energy sources.

With respect to the first goal, PURPA advanced an "all of the above" energy strategy, which was intended to encourage greater energy independence and increased supply diversity in the United States.

The scope of this portion of PURPA was narrowly focused. Utilities were exempted from any requirement to purchase from independent power producers that used the energy sources that had been historically been favored by electric utilities, like coal, residual oil, nuclear and natural gas. Instead, Congress focused on certain unconventional energy sources, like cogeneration, that had not been aggressively pursued by utilities.

Other targeted technologies include electricity produced from biomass and waste, as well as renewable resources like wind, small hydro, solar and geothermal energy. The primary purpose in encouraging investment in these specialized energy sources was similar to the reason why cogeneration was targeted: if PURPA was successful in encouraging new entry, supply diversity would be improved, and the country would reduce its dependence on scarce and nonrenewable resources like coal and oil.

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Q. CAN YOU ELABORATE ON THE SECOND GOAL YOU MENTIONED – ENCOURAGING INVESTMENT BY SMALL INDEPENDENT POWER PRODUCERS?

A. Yes. By requiring utilities to purchase from QF's, Congress was not only encouraging diversity of energy supply sources, but it was also pursuing a strategy of encouraging diversification of suppliers of electric power generation. PURPA was adopted at a time when public policy makers were trying to scale back unnecessary regulations, improve regulatory structures, and rely more on competition to advance the public interest – particularly in industries, like the electric power industry, where competition had been effectively suppressed by government policy.

Perhaps the most memorable and visible example of this new approach was the deregulation of airlines which occurred around the same time. In this industry, safety continued to be tightly regulated, but other rules were changed to remove barriers to entry, encourage new airlines to challenge incumbent firms and to deregulate prices, which had previously been tightly controlled. The resulting increase in competition successfully unleashed a tidal wave of innovations, cost cutting, and price reductions.

Although PURPA was not as visible or dramatic, it reflected much the same pro-competitive philosophy underpinning airline deregulation. Congress sought to gain some of the benefits of increased competition without foregoing the benefits of traditional rate base regulation. The idea was to retain existing constraints on monopoly power in retail

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markets, while introducing new, carefully thought-through constraints on monopsony power in wholesale markets. The key to this strategy was encouraging increased investment and new entry by small, independent power producers, who had the potential to unleash downward pressures on the incumbents' costs and retail prices, without taking the risk of fully deregulating an industry which had many of the characteristics of a natural monopoly.

Thus, it is fair to say that one of the fundamental goals of this portion of PURPA was to encourage, on a narrowly targeted basis, increased competition in the market for electrical generation without jeopardizing continued regulation of other aspects of the industry. The strategy was straightforward: encourage investment in small firms that would use unconventional technologies to produce electricity in competition with the existing, vertically integrated electric utilities.

Q. WHY WAS THIS TYPE OF INVESTMENT ENCOURAGED?

A. Prior to the adoption of PURPA, most electric utilities obtained all, or nearly all, of their power from large centralized generating plants that they owned and constructed themselves, or from similar plants operated by a nearby utility. Congress made a conscious decision in 1978 to deviate from this historical pattern by encouraging investment in small power producers (80 MW or less at any single site) that would be entering the market in competition with the vertically integrated utilities, provided they

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focused on the targeted technologies. This had the effect of introducing a small degree of competition into the industry, encouraging greater geographic diversity, and encouraging the use of unconventional technologies.

Before PURPA, the monopoly power enjoyed by electric utilities in the transmission and distribution of electricity and the regulatory apparatus designed to constrain that monopoly power combined to discourage competition. This was true even for parts of the electric industry – like generation – which did not seem to exhibit the characteristics of a natural monopoly.

For example, before PURPA, few industrial firms would consider generating their own power, even where this would be economically efficient (e.g. utilizing waste heat from the manufacturing process), because there wasn't a ready market for power produced in excess of the firm's own needs. Practical constraints, as well as legal barriers associated with monopoly regulation, made it difficult or impossible for industrial firms to sell power to anyone other than the local utility, and most utilities weren't interested in buying power from new entrants. Rather, electric utilities generally preferred obtaining power from conventional generating plants – particularly ones they owned and operated themselves.

Before PURPA was adopted, the utility's preference for owning and operating its own generating plants using conventional energy sources nearly always prevailed over what

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might otherwise have been commercially viable transactions to purchase from independent power producers that would have ultimately benefited the utilities' customers. The utility was largely immune from pressures to pursue unfamiliar technologies or to buy from independent power producers, because it was effectively both a monopolist (single seller) and a monopsonist (single buyer), within its particular service territory.

Thus, for example, unless an industrial firm was willing to pull up stakes and move to another state, it was forced to pay whatever price the utility charged for whatever power it used, and it was forced to accept whatever price (typically much lower) the utility was willing to pay for any extra power the industrial firm produced. Before PURPA, if the gap between the price charged and the price paid seemed unduly large, an industrial firm could in theory complain to the state regulator about the magnitude of the gap, and ask the regulator to require the utility to pay a higher price, but in practice this option was generally too costly and risky to be worth pursuing. Accordingly, before PURPA, most industrial firms ignored the potential for cogeneration, regardless of how attractive the underlying economics might be, rather than risk undertaking an investment that would be subject to the utility's unconstrained monopsony power, or the uncertain outcome of future regulatory decisions.

This problem was not limited to cogeneration by industrial firms – it also affected the viability of investments in power production by small run-of-river hydro plants and other

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opportunities that existed for generating electrical power on a small scale. The utility was typically the sole buyer of power in the local market, and it controlled interconnection to the power grid, thereby largely determining the viability of small power production by other firms. Absent a well-defined system of constraints on the utility's monopsony power, small power production was an enormously risky proposition that few investors were willing to seriously contemplate.

Q. CAN YOU ELABORATE ON THE DISTINCTION BETWEEN MONOPOLY POWER AND MONOPSONY POWER, AS IT RELATES TO THE HISTORY OF UTILITY REGULATION?

A. Yes. By the early 1900's in most jurisdictions a comprehensive system of regulation to control monopoly power had evolved, which severely limited the ability of electric utilities to impose unreasonable prices, terms, and conditions on their sales transactions with most retail customers. In contrast, prior to the adoption of PURPA, relatively little thought was given to monopsony power, and in most jurisdictions no comparable comprehensive regulatory mechanisms existed to constrain the behavior of electric utilities in their dealings with independent power producers.

As the primary or exclusive potential buyer of electrical energy within their respective market areas, the incumbent electric utilities enjoyed as much "monopsony power" when buying electricity as the "monopoly power" they had when selling energy. Taking

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advantage of their market power, utilities generally decided to construct, own and operate their own generating units, or to purchase power from neighboring utilities, rather than buying from independent firms.

In general, incumbent utilities prevented, or at least discouraged, competitive entry by other firms, even in situations where those firms had a clear efficiency advantage (e.g. the ability to generate electricity less expensively, by taking advantage of waste heat involved in industrial processes), or they were willing to take greater risks in trying new, less familiar technologies.

The result was that electric utilities prevented the consuming public from realizing the benefits of competition by independent power producers, who could potentially bring down costs and bring long term societal benefits by increasing supply source diversity, experimenting with innovative technologies, reducing costs, increasing efficiency, or accepting lower profit margins.

In sum, the potential benefits from imposing regulatory constraints on monopsony power are conceptually similar to the reasons why the monopoly power of the incumbent utilities have long been constrained. However, the existence of monopsony power, and the benefits from constraining it, have not been as widely understood or effectively dealt with.

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Q. CAN YOU EXPLAIN WHY UTILITIES RESIST COMPETITION AND PREFER THEIR OWN GENERATING FACILITIES?

A. There are many factors that help explain why electric utilities have historically resisted competitive entry: (1) There is a natural tendency for utility company management to want to retain maximum direct control over system reliability and other outcomes for which they are ultimately accountable. (2) Management operates within the context of a growth-oriented U.S. corporate culture, which favors expansion of a firm's staff, assets, income, and earnings per share. (3) Management is expected to maximize profits and value for its stockholders, which leads to a strong bias in favor of expanding the rate base, due to the Averch-Johnson effect.[15]

With PURPA, Congress attempted to overcome this resistance by reducing barriers to competitive entry into the electric utility industry without disrupting the more successful aspects of traditional rate base regulation. It did this by providing an overarching federal regulatory structure for implementing state regulatory oversight of transactions between electric utilities and QF's, with a view toward encouraging QF investment.

[15] Named after the authors of a famous article published in 1962 in the American Economic Review, which demonstrated that under typical conditions, rational rate base regulated firms will tend to expand their capital investment beyond the optimal point of maximum economic efficiency. This tendency occurs whenever the allowed rate of return exceeds the utility's actual cost of capital by even a small margin. Theoretically the Averch-Johnson effect could be avoided if the allowed rate of return were set precisely equal to the cost of capital. However, this degree of precision isn't achievable in practice. As well, an allowed return which exceeds a barebones estimate of the cost of capital can be viewed as preferable, since it helps maintain the utility's financial integrity, strengthens its financial ratios, and protects its bond rating.

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However, PURPA did not change the attitudes or preferences of the incumbent utilities. These firms continue to prefer owning and operating their own generating resources for perfectly rational reasons. If the benefits of competitive entry are going to fully emerge, it is necessary for state and federal regulators to actively implement the provisions of PURPA in a way that fulfills the goal of encouraging competitive entry, and placing greater reliance on market forces to advance the interests of ratepayers and the public good.

Q. HAVE UTILITIES CONTINUED TO RESIST COMPETITIVE POWER PRODUCTION, DESPITE THE REQUIREMENTS OF PURPA?

A. Yes. In my experience, utility companies have consistently advocated proposals that have tended to discourage QF investment and justified continued expansion of their own rate base instead. While continued resistance to competitive entry is readily predicted and explained as a matter of economic theory, it's important to realize this is not a merely speculative or theoretical concern, but a fundamental aspect of the industry.

It is helpful for regulators to understand and recognize this aspect of the industry in deciding how to interpret and implement the various provisions of PURPA. Succinctly stated, in a typical retail rate proceeding, the utility will often seek rates that are higher than necessary or appropriate, but in a QF rate proceeding the reverse is true: the utility will often seek rates that are lower than necessary or appropriate. The Commission

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should keep this in mind, and try to strike an appropriate balance which serves the long-run best interests of the consuming public in South Carolina.

The historical record is filled with evidence that confirms the industry's preference for low QF rates, its resistance to QF investment, and its preference for putting generating units into their rate base rather than purchasing power from independent power producers. For example, the industry opposed FERC's rules implementing PURPA, arguing that it was inappropriate to require them to pay QF rates that were equal to their full avoided cost. Utilities fought this battle all the way to the U.S. Supreme Court, which unanimously rejected their arguments, concluding that FERC had not acted arbitrarily or capriciously in requiring utilities to buy QF energy at rates equal to full avoided cost.[16] The Court recognized this would not directly provide any rate savings to consumers, but it accepted FERC's reasoning that it was more important to provide a significant incentive for the development of cogeneration and small power production, and that ratepayers and the nation as a whole will benefit from decreased reliance on scarce fossil fuels and increased efficiency. Since that time, utilities have generally been more circumspect in their efforts to discourage QF development in preference for investing in their own facilities, but they have continued to do so.

[16] *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 103 S.Ct. 1921 (1983)

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Q. CAN YOU EXPLAIN HOW UTILITIES DISCOURAGE INVESTMENT BY INDEPENDENT POWER PRODUCERS?

A. Yes. For instance, utilities often resist negotiating with independent power producers. Rather than seeking "win-win" solutions, they refuse to co-operate, they are slow to offer information that would be useful in clearing up confusion or resolving disputes and they make it easier for a competitor to walk away than to reach agreement. They can also create unnecessary delays in the contract negotiation and interconnection process, making it more costly and difficult to get a project off the ground. Similarly, utilities often insist on QF contracts with much shorter durations than they themselves use when building and financing projects, or the insist upon contractual terms that they would reject if they were on the other side of the negotiation.

They may also seek to impose terms and conditions that will make it more difficult to obtain financing for QF projects, yet which offer little or no benefit for the retail customers on whose behalf they are procuring power. In order to finance a project, QF's will typically need to have already signed a long-term purchase power agreement at fixed or pre-specified prices. Those prices and other terms of the contract are crucial in determining whether banks and other investors will invest the capital needed to complete a project.

Utilities also tend to develop low estimates of their avoided costs and low estimates of what costs customers will incur if they produce the power, rather than a competitor.

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Tellingly, however, they rarely offer to back up the cost estimate for their own generating units with any sort of price guarantee or accept any of the risk of underestimating the costs. There have been many examples where utilities have offered rosy projections of how long it will take, and what it will cost, to build and operate a new generating plant. Once they obtain permission to go forward with the investment, which all but guarantees it will go into rate base, they rarely volunteer details concerning how the investment is turning out in practice. Only in the rare case where extreme schedule delays are experienced, or construction costs vastly exceed the original estimates, does the impact on ratepayers undergo intense scrutiny. More commonly, the gap between the original cost estimate per kWh and the actual costs passed through to customers is not publicly disclosed or thoroughly scrutinized.

All of these problems and risks are alleviated or avoided when the utility obtains power from independent power producers at a guaranteed long-term fixed price. When QF's enter a market pursuant to PURPA, the risks of schedule delays and construction cost over-runs are borne by the competitor. Similarly, when they sign a long-term purchased power agreement ("PPA") at a fixed price, QF's bear all of the risk of future inflation or cost escalations due to changing economic conditions, turmoil in global energy markets, and other unexpected events.

Yet, rather than seeking to encourage competitive risk taking which would benefit their retail customers, utilities prefer to build and operate their own generators. This

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preference is consistent with economic theory, including the Averch-Johnson effect (which predicts that regulated monopolies will seek to expand the size of their rate base investment beyond the point which is economically optimal from a societal perspective). This preference is not just a matter of theory. It is an empirical fact, clearly revealed by the way incumbent utilities have so consistently implemented the requirements of PURPA using tactics to discourage competitive entry. Specific examples I've observed include:

- Adopting an unduly narrow view of what costs can be avoided;
- Shielding their avoided cost calculations from public disclosure, making it harder for potential market entrants to evaluate the long-term investment risks and prospects in a given state;
- Disclosing few details concerning their input, assumptions and avoided cost calculations in their testimony and exhibits, which makes it harder for regulators to identify flaws in their avoided cost calculations or to draw meaningful comparisons between those calculations and those put forward in testimony in other jurisdictions;
- Using different fuel price forecasts to estimate avoided costs than the ones they use to evaluate and defend investments in their own generating units, with those differences consistently favoring more investment being placed into rate base and

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less reliance on purchases from independent power producers;

- Putting their own generating units (existing or proposed) at the "front of the line" during the planning process, and treating their own plants as a fixed element of the planning process, regardless of whether other options (like canceling construction or selling the plant) might be better for ratepayers. This has the effect of treating the QF investment as redundant or unnecessary, and biasing the analysis in favor of a larger rate base, even when this is not in the best interest of their retail customers;

- Effectively discriminating against QF's by not providing them with any compensation or credit for shouldering risks that would be borne by their retail customers when they build and operate their own plants;

- Developing QF rates using inconsistent and/or biased assumptions that are skewed against the QF; and

- Resisting proposals to improve the precision and sophistication of the tariff development process, if the effect of those improvements proposals might be to attract more competitive entry, or to encourage more QF investment.

Unfortunately, utilities' QF tariff filings under PURPA don't always receive the same level of scrutiny as their retail tariff filings. There are many possible explanations for

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this, including the fact that the issues are sometimes unfamiliar, and they arise in the context of highly specialized tariffs which have an immediate, direct effect on very few people.

Q. DO RETAIL CUSTOMERS BENEFIT FROM SETTING QF RATES AT ARTIFICIALLY LOW LEVELS?

A. No. Although low QF rates may be superficially appealing (on the assumption that lower QF rates will translate into lower retail rates through a fuel adjustment and purchased power mechanism), artificially suppressing QF rates does not benefit ratepayers. Any short term benefit from low QF rates is of limited value, because low QF rates discourage QF investment, thereby reducing the amount of energy that the utility will actually obtain at the lower rates. Taken to the extreme, if QF rates are so low that no QF investment occurs, no purchases will be made at the low rates, and there will be no savings available to flow through to retail customers.

Even if some QF developers end up selling some power at an artificially low rate (e.g. they are already committed to their projects before the low rates are established), the potential benefit to retail customers will be limited, because future QF investment will be discouraged and the potential for increased pressure on the utility to operate efficiently will be lost. Instead, customers will be forced to buy more costly power generated by the utility itself. Simply stated, over the long run, retail customers are harmed by low QF

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rates, because low rates shield utilities from competition, reducing pressures for them to minimize their costs.

Furthermore, low QF rates encourage unnecessary expansion of the regulated rate base, thereby shifting risks onto retail customers that could have been borne by QF investors instead. For example, when generating plants are built by utilities, customers bear nearly all of the risks associated with scheduled delays and construction cost overruns. Absent an extraordinary finding of imprudence, which rarely occurs, all of the risks associated with construction are ultimately borne by ratepayers. Even in cases where a plant is retired early, or construction is never completed, ratepayers will normally shoulder the burden of any resulting stranded costs.

In contrast, when independent power producers build plants, customers are shielded from these risks, because they only pay for power that is actually generated, and the price remains the same regardless of what delays or cost over-runs occur during construction. In sum, it is not in the public interest for the Commission to endorse unrealistically low avoided cost estimates, or to adopt low QF Rates. To the contrary, the public interest is best served by encouraging competition, by accurately and fairly implementing the provisions of PURPA and the associated FERC rules.

Q. ARE YOU ADVOCATING SETTING QF RATES AT THE HIGHEST LEVEL ALLOWABLE UNDER PURPA?

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A. No. A middle course is preferable. Retail customers are better served by regulatory decisions that set QF rates away from these extremes, at a point that is closer to, but somewhat below the long run incremental costs that are incurred by utilities when they build and operate their own generating plants. I believe this long-run incremental cost standard is also consistent with the requirements of federal law. It encourages competitive entry by small power producers, without imposing a long-run cost burden on customers, and without subsidizing QF development or running the risk of encouraging economically inefficient levels of QF investment.

Stated a little differently, the public interest is best achieved by establishing rates that leave ratepayers indifferent as to whether energy and capacity is obtained from QF's or from the utility itself under traditional rate base regulation. By setting QF rates equal to the cost of having the utility build and operate its own generating units, PURPA creates a level competitive playing field between utility-owned generation and QF power purchases. This encourages investment by QF developers to the extent they believe they can operate more efficiently or at lower cost, or they are more willing to experiment with new technologies, or they are willing to accept a lower return on their investment than the one paid on comparable investments put into the utility's rate base. This creates healthy competition, which exerts downward pressures on retail rates, pressures the incumbent utilities to minimize their own costs, and benefits retail customers over the long term.

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Q. YOU MENTIONED LONG-RUN COSTS AS THE APPROPRIATE STANDARD. WHY SHOULDN'T QF RATES BE EVALUATED STRICTLY ON THE BASIS OF SHORT-RUN ENERGY COST SAVINGS?

A. For one thing, PURPA requires that QFs be given the option of contracting at long-term avoided cost rates, in recognition that long-term price certainty is typically essential to securing investment in QFs, just as it is with investments in utility-owned generation.[17] I also believe that retail customers (and society as a whole) will be best served by making policy decisions primarily on the basis of long-run costs, rather than narrowly focusing on short-run phenomena, like the fuel savings that are achieved when the incumbent utility's generating units are operated less. Furthermore, the goals of PURPA can best be accomplished by taking a long-term view of the choice between QF and utility-provided power. More specifically, I believe the concept of "indifference" and the calculation of avoided costs should primarily be based upon consideration of the full incremental cost of building and operating generating facilities over their entire economic life cycle.

In the electric utility industry, short-run costs are sometimes less than long-run costs, due to lumpiness of capital additions among other factors. However, ratepayer are required to bear the full long-run cost of plants that are put into the rate base. If QF rates only considered a short-run measure of costs, like the variable operating costs incurred when

[17] *Hydrodynamics Inc.*, 146 FERC ¶ 61,193 (Mar. 20, 2014) at P 34; 18 C.F.R. § 292.304(d)(2).

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operating the utility's generating plants, while ignoring the other (fixed) costs utilities incur (and customers pay) for these plants over the long run, a severe mismatch occurs, and indifference is not, and cannot be, achieved. Stated another way, using a short-run view of avoided costs that fails to consider the full cost of building and operating new generating plants over their economic life cycle will discriminate against QF's, create a barrier to competitive entry, and discourage QF investment.

Accordingly, it has often been recognized that the appropriate measure of avoided costs is one that is equivalent to the total costs incurred when a utility builds, owns and operates new generating plants over their life cycle. Properly implemented, a long-run measure of costs ensures that QF's receive the same amount for their power as the utilities receive for power produced using their own generating plants – no more and no less.

It should also be noted that QF's typically sign long-term contracts to sell their output at "fixed or pre-specified prices" and this is type of contract is needed for them to obtain debt financing. For logical consistency, long-term contracts generally require the use of "long-term estimates of avoided cost."[18]

[18] Edison Electric Institute, PURPA: Making the Sequel Better than the Original, December 2006, Page 9.

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Avoided Cost Methodologies

Q. HOW ARE "AVOIDED COSTS" ESTIMATED?

A. There are three major methods that have been used to develop avoided cost estimates, including (1) the Proxy Unit method (also sometimes referred to as the Proxy Resource or Committed Unit method), (2) the Differential Revenue Requirement (DRR) method, and (3) the Peaker method.[19] The Commission has accepted the use of both the DRR and Peaker methods (SCE&G uses the DRR method and Duke uses the Peaker method) but there is no inherent inconsistency in doing this. To the contrary, all three of these methods are intended to measure the same thing (long run incremental costs), so all three methods can (and should) yield approximately the same total cost per kWh under normal circumstances (assuming each one is properly performed using similar inputs and assumptions).

Q. CAN YOU BRIEFLY EXPLAIN THE PROXY UNIT METHOD?

A. Yes. The Proxy Unit (or Proxy Resource) method is described in the PURPA Title II Compliance Manual as follows:

> This method bases the avoided cost on the cost of the host utility's next planned addition, typically a combined cycle/gas turbine (CCGT) generating unit. This approach essentially assumes that the QF substitutes

[19] PURPA: Making the Sequel Better than the Original, page 9. See also the PURPA Title II Compliance Manual, page 35 and Reviving PURPA's Purpose, Carolyn Elefant, Page 13

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> for a planned utility generating unit, or what is assumed to be the next generating unit. The proxy unit's estimated fixed cost (annualized over the expected life of the unit) determines the avoided capacity cost and the estimated variable cost sets the avoided energy cost. The type and size of the unit or units is determined in an Integrated Resource Process (IRP) or from the utility's planning process, where the planning process, for regulated utilities, follows a state commission-approved procedure. Because this is a relatively simple method to use, the proxy method is very common, although the results largely depend on the type of unit or units chosen as the proxy.[20]

This methodology has many advantages, including the fact that it is relatively straightforward and easily understood. Its flexibility is also an advantage: It can be implemented using data for a generating unit that is currently under construction, or has recently been constructed by the utility, a unit that has been identified for future construction in the utility's Integrated Resource Plan, a hypothetical or surrogate unit, or some combination or variant of these data sources. Later in my testimony I will be using the Proxy Unit method to provide an independent assessment of SCE&G's avoided costs, for comparison with the Company's proposed QF rates.

Q. ARE YOU ASKING THE COMMISSION TO ADOPT THE PROXY UNIT METHOD IN LIEU OF THE DRR METHOD?

A. No, not at all. All three of these methods are intended to measure the same thing, and the choice of a specific method in a specific context is largely a matter of administrative or calculational convenience. It should not have any significant impact on the conclusions

[20] PURPA Title II Compliance Manual, page 35.

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that are reached – assuming consistent assumptions and inputs are used in each instance.

In this instance, it was convenient to use the Proxy Unit method to develop some benchmark cost estimates for presentation to the Commission and to clarify some of the points I make in my testimony. The Proxy Unit method was ideal for this purpose because: (1) it is a relatively straightforward, simple method which is relatively easy to explain, implement and understand; (2) it can be developed using publicly available information, thereby improving transparency and reliability; (3) it offers great flexibility, which made it easier to develop multiple different calculations using a wide variety of different assumptions (e.g. fuel choices and cost scenarios); and (4) it is well suited for consideration of the information that must be provided by utilities pursuant to 18 C.F.R. Section 292.302(b) as I mentioned earlier in my testimony.[21] This is significant, since the FERC rules specifically require state regulators to consider this information in setting avoided-cost based rates, to the extent practicable.[22] Moreover, this avoided cost data is available for many different utilities, potentially facilitating comparisons with data submitted by other utilities. However, none of the conclusions I reach are contingent on the use of the Proxy Unit method, nor am I suggesting the Company, or the Commission,

[21] All of the information submitted by utilities pursuant to this regulation tends to be useful, including the cost of planned capacity additions and firm purchases on the basis of dollars per kilowatt, and the associated costs of each unit, expressed in cents per kilowatt hour. In SCE&G's case, this submission includes the cost of the recently canceled V.C. Summer nuclear generating units, which provides a useful point of reference for comparison with the proposed QF rates.

[22] 18 C.F.R. § 292.304(e).

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should switch to the Proxy Unit method.

Q. CAN YOU BRIEFLY EXPLAIN THE DIFFERENTIAL REVENUE REQUIREMENT METHOD?

A. Yes. The DRR method is described in the PURPA Title II Compliance Manual as follows:

> Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF.[23]

The DRR method, as typically discussed, is a fairly complex approach, requiring the use of two different computer models.

> A planning expansion model is used to develop generation expansion plans both with and without the estimated QF output. The resulting two expansion plans then are used as inputs to a financial planning model that yields the utility's projected revenue requirement both with and without the QF output (assuming that the QF's are a "free" resource). The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected QF output. This avoided revenue requirement includes avoided energy and capacity costs as well as other factors (e.g., taxes)[24]

SCE&G's witness, Dr. Lynch, explains that his avoided energy and capacity cost calculations were developed using a "difference in revenue requirements methodology"[25]

> The base case is defined by SCE&G's existing fleet of generators and

[23] PURPA Title II Compliance Manual, page 35.

[24] PURPA: Making the Sequel Better than the Original, December 2006, Page 11.

[25] Direct Testimony of Joseph M. Lynch, page 4.

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> the hourly load profile to be supplied by these generators. The change case is the same as the base case except that the hourly loads are reduced by a 100 MW profile, which is the maximum required by PURPA regulation 18 C.F.R. § 292.302(b)(1) for utilities with systems larger than 1,000 MW of generation such as SCE&G....
>
> The avoided energy cost is simply the difference between the base case costs and the change case costs. The avoided capacity cost is the difference between the incremental capacity costs in both its base resource plan and the change plan.[26]

As is typical of the DRR method, SCE&G compares two different scenarios. Its avoided cost estimates are based on the computed difference between these scenarios. However, the Company's approach is simplified, because it does not develop a comprehensive, detailed analysis of its revenue requirement under any of the scenarios. Instead, it analyzed various different potential generation expansion plans, then it separately analyzed energy costs associated with those expansion plans using the PROSYM model. At no point in its testimony, exhibits or workpapers does the Company pull all of these calculations together in order to show the actual revenue requirement corresponding to various combinations, nor does it demonstrate that the approach it is choosing to model is consistent with minimizing its revenue requirements (or minimizing rates charged its retail customers).

The Company was asked in discovery to produce "[c]opies of all work papers and source documents, utilized or relied upon in formulating SCE&G's request for a new PR-2

[26] *Id.*, pages 4-5.

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Rate." In response it provided various workpapers which do not actually compute its rate base or develop its operating expenses, revenues, and miscellaneous sources of income in a manner that is equivalent to the way its revenue requirements would be developed in a retail rate case. Instead, it adopts simplifying assumptions and inputs which, as I will explain later in my testimony, lead me to question the reliability of its calculations.

While the Company used a powerful computer modeling tool (PROSYM) which is capable of analyzing many different scenarios it didn't use the full power of computer modeling to analyze its revenue requirements in full detail. Furthermore, it relied on some assumptions that are completely unrealistic, it adopted some assumptions that are speculative or highly improbable, and it failed to evaluate some important strategies to most effectively deal with the cancellation of the nuclear units, as well as the growth of solar on the Company's system.

All of these problems are important in this case, having a direct impact on the conclusions the Company reached, and the avoided cost calculations it proposes to use for its new QF rates. I will discuss these problems in more detail later.

Q. CAN YOU BRIEFLY EXPLAIN THE PEAKER METHOD?

A. This is the method which Duke has historically used in both South and North Carolina. The Peaker Method is described in the PURPA Title II Compliance Manual as follows:

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> Under the peaker method, the value of the QF's capacity is determined by assuming that the QF will be operating as a utility peaking unit. If the utility requires capacity, this method sets the avoided capacity at the lowest-cost capacity option available to the utility, for example, a combustion turbine (CT). Avoided energy cost may be based on the utility's system-wide avoided energy cost, not the peaking unit's energy cost. This requires production cost modeling to determine the system-wide avoided energy cost, which increases the complexity of this method over the "proxy" unit approach.[27]

The Peaker method has at least one significant advantage: it develops energy cost estimates on an hour-by-hour, year-by-year basis. However, some of this advantage can be lost when the calculations are averaged and levelized across broad, potentially arbitrary "Peak" and "Non-Peak" categories and seasons (groups of months). The Peaker Method also has at least one significant disadvantage: it is not especially well-suited to fully utilize the information provided pursuant to 18 C.F.R. Section 292.302(b), particularly with regard to the incremental cost of nuclear and other baseload generating units, since this data isn't used in the Peaker Method.

Q. DO ALL THREE OF THESE METHODS ESTIMATE THE INCREMENTAL COST OF BUILDING AND OPERATING NEW GENERATING FACILITIES OVER THEIR ECONOMIC LIFE CYCLE?

A. They can and they should. Whether or not this is actually accomplished in practice depends on whether they are correctly implemented, with appropriate assumptions and

[27] PURPA Title II Compliance Manual, page 35.

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inputs.

It is easiest to see this with the Proxy Unit method, which specifically focuses on the life cycle cost of owning and operating a specific unit. Like any method, the costs that are calculated will vary – particularly on a per kWh basis – depending on the assumptions and inputs which are selected, and how they are used. For instance, if avoided costs are being calculated for use in paying QF's for power that will be generated during many hours of the year, the primary focus should be on a proxy unit that is cost-effective in serving long duration loads, like a Combined Cycle or Nuclear unit. If the analysis were limited to a peaking unit instead, the resulting cost per kWh could be higher than the full life cycle cost of owning and operating a baseload plant, because a combustion turbine has very high fuel costs, which outweigh its low construction costs if power is going to be provided during many hours of a typical day.

In the case of the Differential Revenue Requirement method, the opposite problem can arise, but the outcome will again depend on the inputs and assumptions that are actually used. There is nothing inherently invalid about the DRR method – but the results can easily be skewed against the QF, depending on what inputs and assumptions are used. In particular, with the DRR method it is imperative to show that the revenue requirement is being appropriately minimized in each scenario – consistent with the way retail ratepayers should be protected from monopoly power by ensuring that the revenue requirement used setting retail rates is not excessive or unreasonable.

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Under the DRR method, key inputs and assumptions should all be adapted to the circumstances, to ensure that the revenue requirement is minimized under each specific scenario that is considered. For instance, in the "change" scenario which includes a "free" block of 100 MW of power provided by a QF, appropriate inputs and assumptions should be used (or adjusted) to ensure that the full long-run benefit of having this block of power available is taken into account. If inappropriate or overly simplified inputs or assumptions are used, there may appear to be little difference between the two scenarios, and thus the value of the "free" block of power may be underestimated. When the revenue requirements in both scenarios are correctly analyzed, comparing two optimal long-run scenarios in which the revenue requirement is minimized consistent with the circumstances of that scenario, the comparison should reveal the true economic value of the power being provided by the QF. In turn, when this method is implemented correctly, one would expect the final conclusion to be fairly similar to the full cost of building and operating generating units capable of providing the hypothetical "free" block of power.

The Peaker Method will also achieve this benchmark when appropriately implemented, although it isn't intuitively obvious how it can accomplish this, since this method focuses on the capital cost of a peaker (combustion turbine or CT) rather than a base load plant. However, according to the theory underpinning the Peaker Method, assuming appropriate assumptions are used in running the production cost model (e.g. PROSYM), the marginal running costs of the system (output from the model) should exceed the running costs of a

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new baseload plant by just enough margin to compensate for the added cost of the baseload plant, relative to the cost of a new peaking unit.

> According to the theory underlying the Peaker Method, if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. It will also equal the avoided cost of a baseload plant, despite the fact that the capital costs of a peaker are less than those of a baseload plant. This is because the lower capital costs of the CT are offset by the fuel and other operation and maintenance expenses included in system marginal running costs, which are higher for a peaker than for a new baseload plant. Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.[28]

Although it isn't intuitively obvious, this reasoning is fundamental to the theory underlying the Peaker Method, which assumes combustion turbines with poor heat rates will be operated at the top of the dispatch stack during enough hours of the year to ensure that the difference in fuel costs (e.g. between a new peaking unit and a new nuclear generating unit) will compensate for the additional capital costs of the baseload unit.

Stated another way, the Peaker Method doesn't provide recovery of the high fixed costs of a baseload plant like a Combined Cycle unit or nuclear plant in the avoided capacity cost results. Instead, the capacity costs are limited to those of a CT, while the remainder

[28] North Carolina Utilities Commission, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 100, September 29, 2005, Page 17.

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of the fixed costs of owning and operating a baseload plant are supposed to show up in the energy costs. The avoided energy costs are based upon the "top of the stack" (typically, the least fuel-efficient generating unit that is running during any given hour), which are expected to exceed the cost of fuel for baseload units by an amount that should be large enough to recover the portion of the baseload plant investment that exceeds the investment in a peaking unit.

Q. CAN YOU BRIEFLY HIGHLIGHT SOME PRACTICAL ISSUES WITH RESPECT TO PRODUCTION COST MODELS, LIKE PROSYM?

A. Yes. SCE&G relies on computerized production cost modeling to estimate its avoided energy costs on an hour-by-hour, year-by-year basis. The great advantage of these models is that they produce cost estimates in extreme granular detail (literally 8,760 different cost numbers are generated for each year), and they can easily accomplish this level of granular detail for many different scenarios – simply by adjusting the inputs used in running the model for each scenario. For instance, a production cost model can easily develop precise estimates of how costs will be affected during various time periods and seasons, depending on what happens to fuel prices in future years. Similarly, it can provide this sort of highly granular cost information for scenarios reflecting other uncertainties, like the timing of when the V.C. Summer nuclear units were expected to be completed, or how much the Company's energy costs (and retail rates) could be reduced if some of the excess energy that becomes available when these units are finished were to

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be sold to other utilities.

Unfortunately, the Company did not provide the detailed, hourly PROSYM output with its testimony in this proceeding, nor did it provide this information in response to discovery. Instead, it summarized or aggregated this data across broad on-peak and off-peak time periods. This obscures some of the potential benefits of using PROSYM, which is capable of developing energy costs on a detailed, hour-by-hour, month-by-month, and year-by-year basis. Similarly, the Company didn't take full advantage of PROSYM's inherent "What if" capabilities to provide the Commission and other interested parties with energy cost estimates under multiple different scenarios (e.g. higher or lower fuel prices in future years, or varied rates of growth in solar energy).

This failure to take full advantage of PROSYM's capabilities is not something that can easily be rectified, especially given the time constraints that apply to this proceeding. This problem highlights one of the most significant disadvantages of using a production cost model: they are data-intensive and costly to license. Furthermore, extensive training is required before these models can be operated reliably. Because of these licensing and training barriers, the model effectively becomes a "black box" which cannot easily be penetrated by the Commission, ORS or other parties. Due to licensing and other barriers, other parties cannot readily test or modify the underlying inputs and assumptions that drive the avoided energy cost estimates produced by a model like PROSYM. This is a significant problem, since the inputs largely control the outputs of these types of

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computer models.

Avoided Energy Costs

Q. HAVE YOU DEVELOPED ESTIMATES OF THE COMPANY'S AVOIDED ENERGY COSTS?

A. Yes. I developed several long-run avoided energy cost estimates using the Proxy Unit method. Some of these estimates are based on a hypothetical nuclear plant, similar to the recently canceled V.C. Summer project, some are based on a hypothetical Combined Cycle plant, and some are based on a hypothetical Combustion Turbine. I also considered several different fuel cost scenarios, as I will explain later in my testimony.

When thinking about energy costs, maintenance, fuel and other operating costs that vary with energy output are what immediately come to mind. However, it's important to note that my energy-related cost estimates also include certain fixed capital-related costs. Dr. Lynch, in his direct testimony on behalf of SCE&G in this proceeding, alluded to this complication, in the context of the requirement under PURPA that QF rates consider both avoided energy costs and avoided capacity costs:

> Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.[29]

[29] Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Page 4 (citing Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies

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Ultimately, what is most important is the total price paid to the QF for the energy it provides – including the portion of the price which compensates for variable operating costs avoided, as well as the portion which compensates for the capital-related costs that provide the ability to produce electrical energy. To maintain consistency with the requirements of PURPA, and to draw a meaningful distinction between energy and capacity costs, it's important to realize that the share of total costs that are fixed (capital-related) relative to the share that is variable will depend on the technology that is used to generate the electricity. The costs of producing energy using hydro and nuclear involves mostly fixed costs, while technologies that burn coal or gas necessarily require a much higher proportion of variable costs (primarily due to the cost of the fuel that is burned).

In order to arrive at a meaningful and useful distinction between costs that are capacity related and costs that are energy related, it is useful and necessary to recognize that some of the capital-related costs of building and owning a generating unit are better thought of as energy-related. Thus, the most useful and meaningful distinction that can be drawn between capacity-related costs and energy-related costs is not identical to the distinction between fixed costs and variable costs, nor is it identical to the distinction between capital-related and operating expense-related costs.

Act of 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980)).

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Q. HOW DID YOU SPLIT FIXED COSTS BETWEEN THE ENERGY AND CAPACITY RELATED CATEGORIES?

A. I assumed the "capacity-related" portion of nuclear and combined cycle units are limited to the equivalent annual fixed cost of building and owning the combustion turbine. The remainder of the fixed costs of building and operating the nuclear plant and combined cycle plant are treated as part of the energy-related costs, rather than classifying them as capacity-related costs. This disaggregation of fixed costs is widely accepted – in fact, it is fundamental to the theoretical underpinnings of the peaker method.

The extra step involved in disaggregating fixed costs is particularly useful when examining the economics of a hydro or nuclear unit. In fact, the great majority of the capital investment in a hydro or nuclear plant is not attributable to the goal of meeting peak capacity (although hydro and nuclear plants also provide capacity that help achieve that goal). Rather, the bulk of the investment in a nuclear plant is attributable to the goal of safely producing energy with low fuel costs.

The water (and gravity) used to operate a hydro plant, and the uranium used to fuel a nuclear plant costs are less costly than coal, oil or natural gas – and this cost advantage is a key motivation for using these capital-intensive technologies. No one would invest in a nuclear unit just to provide capacity during peak hours. The added investment expended on baseload plants is only justified by the potential for minimizing fuel and other variable costs over the operating life of the plant. Consequently, any investment in excess of that

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required for a peaking plant is appropriately categorized as energy-related. The same logic applies to disaggregating the costs of the combined cycle plant, although the impact is not as significant.

After drawing this distinction, the levelized fixed annual cost estimates in 2017 dollars are summarized in the following table:

Cost per KW/Year	Nuclear	Combined Cycle	CT
Capacity Related	$ 82.36	$ 87.12	$ 87.12
Energy Related	565.60	48.86	0.00
Total[30]	$ 647.96	$ 131.23	$ 87.12

Q. ARE THERE ADDITIONAL COMPLICATIONS RELATED TO FLUCTUATIONS IN FUEL COSTS?

A. Yes. Aside from complications attributable to the existence of capital-related costs needed to produce electrical energy, the most important complication is the fact that future energy costs depend on the future level of fuel prices, which are volatile, and cannot be accurately predicted advance. In fact, because fuel prices are notoriously volatile, they are typically removed from the standard measures of inflation used by

[30] The details of the calculations used in developing these cost estimates are discussed later, in the section of my testimony concerning capacity-related costs.

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economists, stock market analysts, members of the Federal Reserve Board, and other knowledgeable observers when they are analyzing inflation.

The problem is especially acute with crude oil and natural gas prices. While these fuel sources have exhibited a tendency to trend higher and higher over the long term, they have also exhibited a tendency to fluctuate wildly over both short and medium time frames, making it very difficult to make optimal long-term investment decisions, or to anticipate the long term impact of any decisions related to energy usage. This is a problem that has been experienced by automobile manufacturers, airplane manufacturers, airlines and other firms that make long-term investments anticipating one level of energy prices, only to find those decisions to be sub-optimal (sometimes disastrously so) because energy prices ended up being different than they expected.

The problem with short term price instability was vividly illustrated as recently as 2016, when natural gas prices plunged by more than 20% during a few months early in the year, and then shot upward by nearly 40% over an even shorter time period later in the year.

In the following year, 2017, gas prices stabilized to some degree, albeit at very low levels by long term historical standards – in fact, the Wall Street Journal had a headline on the front page of its March 15, 2017 edition with the headline "Natural-Gas Glut Deepens." Prices subsequently bounced off the low of $2.88 experienced during March 2017, averaging $3.15 in May 2017, and thereafter fluctuating in a range from $2.82 to $2.98

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during most of the year. The notable exception was November 2017 when milder than expected weather resulted in prices dropping to the low of the year – $2.01. Yet, two months later, in January 2018, unexpected cold weather led to gas prices shooting up to $3.87 – the highest prices observed since September 2014.

Recent improvements in gas drilling and extraction technology have led to an increase in supply relative to demand, which has contributed to unusually low prices by historic standards – averaging just $2.63 in 2015, $2.90 in 2016 and $2.90 in 2017. At these price levels, natural gas is so inexpensive it is displacing other options – especially coal and new nuclear plants. In some markets, low gas prices are even leading some observers to question the continued viability of maintaining and operating older nuclear plants. However, it would be a mistake to draw strong conclusions about the relative merits of different technologies solely on the basis of a few years of unusually low natural gas prices. To the contrary, gas prices have repeatedly experienced extreme fluctuations over multi-year periods.

Generating plants are 30+ year investments, so the relative merits of each technology cannot meaningfully be evaluated strictly based upon current fuel prices. The decision to invest hundreds of millions of dollars in a new generating plant should be taken from a long term perspective, taking into account the risk that prices will change dramatically over the life cycle of the investment. In the case of a natural gas-fired generator, a significant risk exists that gas prices might suddenly double or triple, which would

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drastically change any conclusions one makes about the merits of the investment.

In fact, the instability of natural gas prices, and difficulties associated with predicting these prices for decades into the future is one of the principal disadvantages, or risks, associated with using this fuel source. These risks are important to keep in mind when evaluating the merits of long-term investments in gas-fueled generation relative to other options. Coal has some of the same risk characteristics as gas, but to a lesser degree, since coal prices tend to be more stable and because coal can be sometimes be purchased from coal mines pursuant to multi-year contracts at fixed prices.

The key point is that fuel price assumptions or projections are of critical importance when evaluating generating technologies or estimating energy costs using different fuel sources. In fact, the fuel cost assumptions will at least heavily influence, if not entirely determine, the conclusions that are drawn from an analysis of the relative cost-effectiveness of using different generating technologies.

Q. CAN YOU ELABORATE ON THESE PROBLEMS?

A. Yes. The following graph shows the long term upward trend in natural gas prices from 1990 through 2017. The light blue bars show average gas prices experienced during each of these years, using data obtained from Reuters (1990-96) and the Energy Information Administration (1997-2017). The dark blue line shows the linear trend reflected in that historical data, extended into the future. Finally, the pale yellow bars on the right side of

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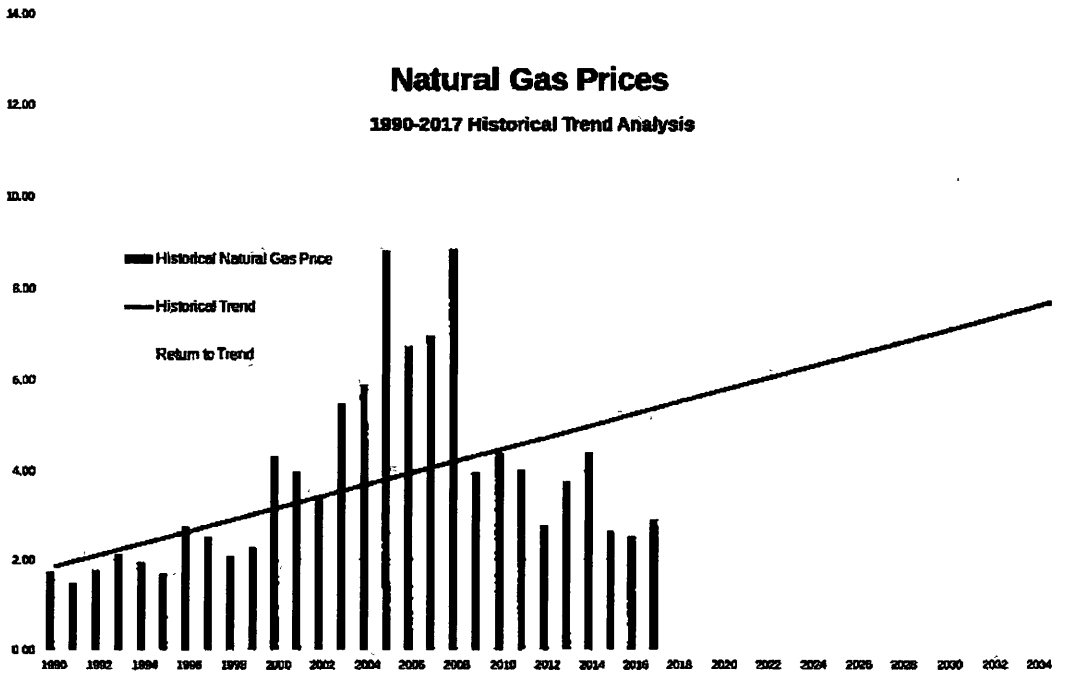
the graph shows what future would look like, if gas prices were to smoothly return to the historical trend line and follow the slope of the historical trend line thereafter.



Given the wide fluctuations observed in the historical data (light blue bars), it is apparent that gas prices cannot be accurately predicted years in advance of when it is actually used. This uncertainty greatly complicates any attempt to analyze the cost of producing electricity using different fuels.

This problem is particularly acute when comparing the cost of generating sources that burn fossil fuels with those that don't. Simply stated, electricity produced with fossil

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fuels is subject to price risks that other technologies, including nuclear power, hydro, biomass, solar, geothermal and wind, are largely immune to. Any attempt to decide whether fossil fueled electricity is a higher or lower cost option for ratepayers will be almost entirely dependent upon your assumptions or projections concerning future fossil fuel prices.

This difference in risk characteristics is of vital importance when trying to analyze the impact on ratepayers of obtaining power from a QF at a guaranteed long-term fixed price, compared to the alternative of building a new generating plants that burns fossil fuel (or purchased power from a merchant plant that uses fossil fuel). The fossil fuel option is subject to significant pricing risk which are not applicable to technologies with low variable costs, like hydro and solar. Since fuel prices are subject to rapid change, and they not cannot be reliably predicted years in advance, this pricing uncertainty should be considered when attempting to evaluate the pros and cons of different generation sources. SCE&G considered this problem when evaluating its nuclear construction program, but it ignored the problem when evaluating appropriate price to pay QF's.

All else being equal, a customer will prefer a guaranteed fixed price to a mere estimate of what they might end up paying. To leave a customer indifferent between a renewable QF energy source at a guaranteed fixed price, and a fossil fuel source it is necessary to add a risk premium to the former option before attempting to draw any meaningful conclusions about which technology is preferable from a customer perspective. This is true regardless

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whether one is considering the construction of a new gas fired generator, purchasing electricity on the wholesale market at prices to be determined when the electricity is delivered, or by running one of the utility's existing generators – if the power comes from a fossil fuel source, the seller will almost never be willing to accept the pricing risk. Instead, the retail customer is forced to shoulder the burden of the pricing risk. This difference in risk is significant and should not be simply ignored.

Q. CAN YOU PROVIDE A REAL-WORLD EXAMPLE SHOWING HOW PRICING RISKS CAN BE DEALT WITH?

A. Yes. In its 2015 evaluation of the economic viability of its V.C. Summer nuclear construction project, SCE&G considered several different scenarios concerning potential future gas prices – all of which were higher than the unusually low prices that have recently been observed.[31] SCE&G started with

> two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2015 Annual Energy Outlook (AEO). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor ... to forecast prices beyond three years in the future.[32]

[31] South Carolina Electric & Gas, Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, May 26, 2015.

[32] *Id.*, Page 3.

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The latter forecast, which it described as its "base line forecast" of natural gas prices, was the lowest of three forecasts it developed and used for its evaluation. SCE&G also evaluated the impact of natural gas prices being 50% higher (Scenario 2) or 100% higher (Scenario 3) than this baseline.[33]

Recognizing that "all forecasts of future gas prices are subject to error" SCE&G looked at multiple scenarios, with their Baseline Scenario 1 forming the bottom of the range, Scenario 2 and the EIA's 2015 forecast falling in the middle, and Scenario 3 moving well above the others. Strictly speaking, Scenario 3 was not the highest pricing scenario SCE&G considered, since it also considered the impact of adding an estimate of the cost of carbon to natural gas prices.

[33] *Id.*, Page 3.

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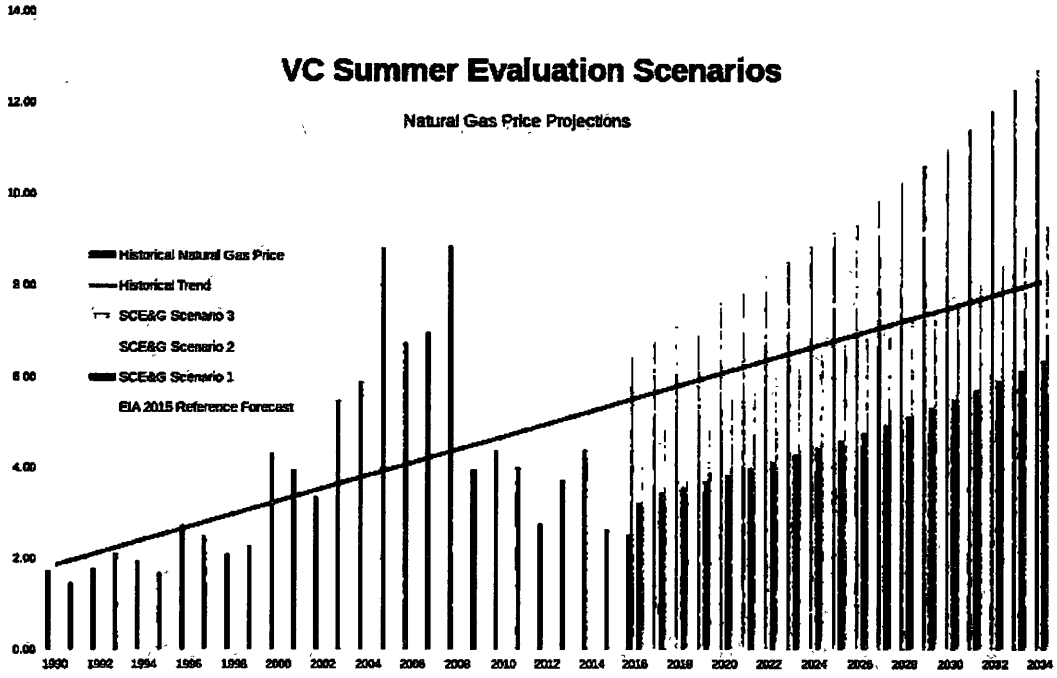

1 The three SCE&G scenarios are shown in the above graph, which also includes historical
2 data and the historical trend line through 2016.

3 When reviewing this graph, it is important to keep in mind that the V.C. Summer
4 evaluation was completed in June 2015, before most of the 2015 prices, or any of the
5 2016 prices were known.

6 The risks associated with higher natural gas prices were pivotal to the Company's
7 conclusion in 2015 that it should continue to invest in construction of the nuclear units,

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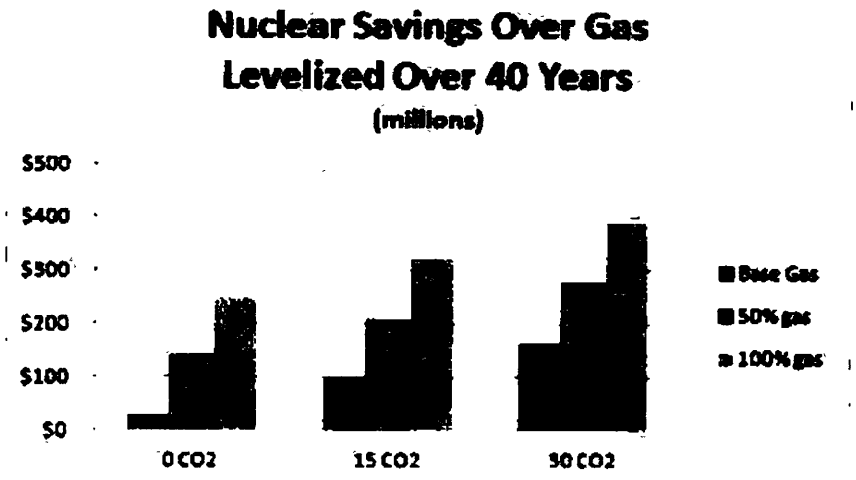
despite the enormous sums required to complete them. This is clearly shown in this graph, which summarizes some key results of the study:[34]

CHART H



The group of three bars at the far left assumed no future government action penalizing or restricting carbon dioxide pollution. Absent any consideration of these environmental and political risks, continuing with nuclear construction was just barely superior to canceling the nuclear units and burning natural gas instead. This corresponds to the "Base Gas" pricing scenario (shown in blue at the far left) which was expected to result in $28 million of annual savings. This was a relatively small amount in the context of a risky, multi-billion dollar investment.

In its report, the Company interpreted these results as favoring continued construction of

[34] *Id.*, Page 8.

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the units:

> This Chart highlights several critical points. First, completing the nuclear construction program is more economical than switching to a gas resource strategy across all scenarios modeled. In not one case is gas less costly than nuclear. The lowest level of nuclear advantage is a levelized annual advantage of approximately $28 million per year. This occurs using base gas price assumptions and CO2 prices at $0 per ton. In the 2008 Studies, the $0 per ton CO2 scenario with low gas prices resulted in nuclear being more costly than gas by $44 million.[35]

While not explicitly stated in the report, it was self-evident that, if gas prices turned out to be even a small amount lower than the Base Gas forecast, the natural gas option was going to be less costly than continued construction of the nuclear units. SCE&G had already spent $3 billion on the units at this point.[36] Although this past investment was being excluded from the analysis (on the theory that retail ratepayers were obligated to reimburse these costs regardless of whether or not the project was abandoned), billions of dollars of additional work still needed to be done. These "going forward" costs were the only ones being evaluated.

Given the inherent risks associated with nuclear construction, this going-forward investment only made sense if one believes the nuclear energy will ultimately save money compared to the energy it will displace. In turn, any conclusions about this tradeoff is necessarily a function of the assumptions one makes about future fossil fuel

35 *Id.*

36 *Id.*, Page 3.

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costs and risks. The Company fully understood the significance of these uncertainties and risks, as indicated by this passage in the report:

> ...the study shows that the comparative economics of the nuclear and natural gas resource strategies swing widely based on gas price forecasts and future CO2 cost assumptions. This shows that the economics of the gas resource strategy are very sensitive to swings in natural gas prices and CO2 costs. This confirms that a resource strategy dependent of natural gas generation significantly increases SCE&G's exposure to fossil-fuel volatility and environmental cost increases.[37]

In fact, the decision whether to abandon the project or go forward with construction was almost entirely dependent on what level of fuel costs were estimated to occur over the 60 or more years, and how the risks associated with that estimate. A net present value difference of $28 million per year was clearly not a sufficient basis for continuing to incur the nuclear scheduling, regulatory, and cost risks, unless those risks were outweighed by the risk of sharply higher fossil fuel costs at some point during the useful life of the plant.

The trade-off between construction risks and fuel price risks is one that has long been understood by utilities – since the industry has frequently encountered difficulties constructing new nuclear units on schedule or at the originally estimated cost. Problems with schedule delays and construction cost over-runs are risks that have been widely recognized since the late 1980's, as indicated by the many proposals that have been

[37] Id., Page 9.

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offered since that time with respect to reforming nuclear regulation and nuclear construction practices, in an effort to make nuclear power a less risky, more cost effective alternative to fossil fuels.[38]

Q. WERE ANY OTHER RISKS CONSIDERED BY SCE&G IN EVALUATING WHETHER TO CONTINUE WITH CONSTRUCTION OF THE NUCLEAR UNITS?

A. Yes. The primary other rationale offered by SCE&G was the potential benefit of achieving a more "balanced" generating portfolio – one that avoided placing excessive reliance on fossil fuels. A more "balanced" portfolio of generating resources would provide better protection from the environmental and legal risks associated with being heavily reliant on fossil fuels – risks which apply to both coal and natural gas. The Company quantified some of the associated environmental and political risks by studying alternative scenarios in which a "price of carbon" would eventually be imposed on

[38] See for example: E. Ray Canterbery, Ph.D, Don Reading, Ph.D, and Ben Johnson, Ph.D, "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." Southern Economic Journal, January 1996.

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burning fossil fuels. These risks (and associated scenarios) were reflected in the use of multiple rows this chart:

CHART I
Base Load Scenario

Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years ($MM)			
	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$28	$144	$248
$15 CO2 Price	$97	$210	$326
$30 CO2 Price	$166	$278	$392

In effect, the environmental and political risks associated with fossil fuels were quantified by evaluating scenarios which included a "price of carbon" of $15 or $50 per ton. These risks (together with the fuel price risks discussed earlier) were the underlying basis for why the Company felt it was important to avoid excessive reliance on fossil fuels. The logical connection is clearly reflected in this passage:

> A significant advantage of continuing construction of the two nuclear units is that once added to SCE&G's generation fleet, the Units will produce a well-balanced capacity portfolio. The following charts show the percent distribution of capacity under a plan of continuing nuclear construction and the alternative of replacing it with natural gas fired capacity.

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CHART A

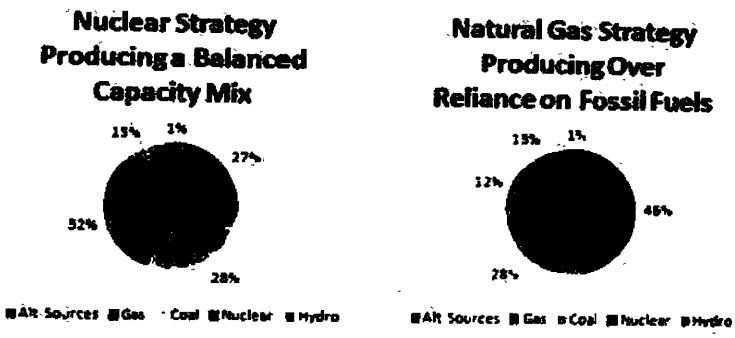

Chart A shows that the Natural Gas Strategy produces a generation system that in 2021 relies on fossil fuels for 73% of its generating capacity. The Nuclear Strategy creates a more balanced portfolio. Such a portfolio better protects customers from unexpectedly high costs in any one fuel source while allowing the utility to take advantage of opportunities in others.

Q. IN DEVELOPING ITS PROPOSED QF RATES IN THIS PROCEEDING, DID THE COMPANY EVALUATE THE BENEFITS OF A BALANCED GENERATING PORTFOLIO?

A. No. In developing its avoided cost estimates and its proposed QF tariffs, SCE&G ignored the potential benefits of achieving a more balanced generating portfolio as it increases the amount of QF power it purchases.

Q. DID SCE&G USE MULTIPLE SCENARIOS TO COMPARE THE RISKS OF FOSSIL FUELS TO THE RISKS OF QF POWER?

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A. No. I've seen no indication that SCE&G evaluated the impact of different future trajectories in fuel prices, nor did I see any indication it gave any consideration to the environmental and political risks associated with excessive reliance on fossil fuels. More specifically, I saw no evidence it used multiple fuel price scenarios to develop its "Base" expansion plan, nor did I see any evidence it systematically evaluated the impact of these risks in the context of any of its DRR "Change" scenarios.

This is not due to any limitation in the Commission-approved Differential in Revenue Requirements methodology. The DRR method is fully capable of evaluating these types of risks, assuming appropriate inputs and assumptions are used. All the Company needed to do was to analyze multiple different generation expansion plans, and then run PROSYM using multiple input scenarios corresponding to different risk scenarios (e.g. different fuel cost levels and carbon prices).

Had the DRR method been implemented in this manner, the Company could have provided the Commission with better, more useful information concerning the QF-related issues in this proceeding. It could have shown the Commission how the Company's Revenue Requirements will differ depending on the level of fuel prices which occur in the future, and how the previously mentioned political and environmental risks play out. By failing to evaluate multiple scenarios, the Commission lost the ability to evaluate the risks and that will be borne by ratepayers if adopts policies that discourage competitive QF investment in renewable energy, and favor monopoly investment in fossil fuels.

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In this proceeding SCE&G apparently just ignored the benefits of a more balanced generating portfolio. The failure to consider these risk differences is such a serious error that it is a sufficient basis, in and of itself, for rejecting the Company's proposed QF tariff revisions. Furthermore, the extreme inconsistency between the approach used in this proceeding and the one used in evaluating the nuclear construction program calls into question the Company's credibility. If it were concerned about maintaining its credibility, objectivity and consistency, the Company would at least have made sure to study the same risks it focused on when deciding to continue with building the nuclear units.

Q. CAN YOU BE MORE SPECIFIC IN EXPLAINING HOW FOSSIL FUEL RISKS COULD HAVE BEEN STUDIED IN THIS PROCEEDING?

A. Yes. Under the DRR method, "Base" and "Change" expansion plans are compared.

> As approved by the Commission in Order No. 2016-297, SCE&G uses a difference in revenue requirements methodology to calculate both the energy component and the capacity component of its avoided costs. ... The base case is defined by SCE&G's existing fleet of generators and the hourly load profile to be supplied by these generators. The change case is the same as the base case except that the hourly loads are reduced by a 100 MW profile, which is the maximum reduction required by PURPA regulation 18 C.F.R. § 292.302(b)(1) for utilities with systems larger than 1,000 MW of generation such as SCE&G. Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Page 4.

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This description is largely accurate, although somewhat misleading.[39] In particular, the Company's "base case" was not limited to the "existing fleet of generators." The "base case" also includes expected additions of new QF solar capacity, as well as two new combined cycle plants. These expected changes to the existing generating fleet were not disclosed by Dr. Lynch in his testimony, but they were included in every potential version of the Company's "Base" expansion plan.[40]

However the assumptions (which understate the amount of solar capacity that will be coming onto the grid) were however explained in the Company's 2018 Integrated Resource Plan.

> SCE&G's resource plan for the next 15 years is shown in the table labeled "SCE&G Forecast Summer and Winter Loads and Resources – 2018" ... line 7 the resource plan shows the amount of firm solar capacity expected to be added to serve the system summer peak. As shown on line 5, by 2020 this solar capacity accumulates to 865 MWs of solar capacity but only 35% of this capacity is assumed firm and therefore reflected in the resource plan.[41]

To be clear, in developing its Base expansion plan, the Company did study several different investment strategies or scenarios. For instance, it tested the impact of varying the timing of new rate base investments, and it experimented with different combinations

[39] It is worth noting that 100 MW is actually the maximum reduction allowed under PURPA, rather than being a requirement. Utilities are free to use a smaller increment in estimating avoided costs.

[40] See the tab "Expansion" at cells K14 through K24 in: EPLAN17_Summer-Winter_CC2023_(112017).xlsx,

[41] SCE&G 2018 Integrated Resource Plan, page 40.

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of combined cycle units and combustion turbines.

However, I saw no evidence that any of these strategies were evaluated using multiple fuel price scenarios. I also noticed that all of the strategies assumed acquisition of the Columbia Energy Center (part of the Dominion merger proposal) would be approved. No evaluation was made to determine the optimal expansion plan if the proposed acquisition of the Columbia Energy Center, or the proposed Dominion merger, were rejected. Furthermore, there was very little testing of the impact of engaging in firm energy purchases, rather than adding more generating units to the Company's rate base.

More potential expansion strategies should have been considered, and all of the strategies should have been "stress tested" or evaluated using several different sets of assumptions, particularly with respect to different fuel price scenarios. The optimization process used to select the "Base" expansion plan should have clearly demonstrated that the selected expansion plan had the lowest expected revenue requirement, after adjusting for differences in risk.

Q. CAN YOU GIVE A SPECIFIC EXAMPLE OF SCENARIOS THAT SHOULD HAVE BEEN STUDIED WITHIN THE DRR ANALYSIS, BUT WERE NOT?

A. Yes. I saw no evidence the Company gave any consideration to the tradeoffs between rate base investments and wholesale power market transactions, much less sought to achieve an optimal mix of rate base investments and power purchases. Yet, in past

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proceedings the Company used purchased power contracts to help minimize its revenue requirement, and provide added flexibility with respect to the timing of when the nuclear units would be completed.

In this proceeding the Company is attempting to modify its Base expansion plan, rather than using the same one that was used in last year's QF filing. It not only removed the nuclear units, but it developed a new expansion plan that replaces those units with fossil fuel generating plants owned by Company. To help minimize the revenue requirement, it should have studied the effect of using firm purchased power contracts accommodate an optimal portion of the energy and capacity needs that were previously being met by the nuclear units. Without evaluating the purchased power option, there is no valid basis for arguing or assuming that the new "Base" expansion plan is appropriate for use in the DRR method. The problem is that lacking any use of purchased power contracts (particularly the purchase of firm blocks of energy only during peak hours, when energy is most needed), it failed to confirm whether the newly defined "Base" expansion plan minimizes the revenue requirement. In turn, without properly minimizing revenue requirements in the "Base" case, any comparisons that are made to the QF-related "Change" case will not be consistent with one of the most foundational requirements of the DRR method.

In considering this concern, the Commission should keep in mind that evaluating the pros and cons of investing in new capacity or purchasing output from another firm is

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something firms routinely do all the time. Sometimes referred to as the "make or buy" decision, this is not an exotic choice that could easily be overlooked. Nor is the decision whether to generate power or to purchase from another firm a purely hypothetical option that has little applicability to the electric utility industry in general, or the Southeastern United States in particular. SCE&G is fully aware of the fact that some generating plants in the Carolinas are currently being operated as "merchant plants" selling their electrical output to the wholesale buyers. At the very least, the Company should have investigated whether any of these firms would be interested in negotiating the sale of portions of their output to SCE&G. Similarly, there are numerous merchant generators in the PJM market that might be willing and able to sell firm power to SCE&G.

Admittedly, purchases of firm blocks of power from merchant plants might have a higher expected cost than adding more fossil fuel plants. However, the expected cost is not the only factor to consider, as discussed earlier. A purchase power strategy might be preferable from a retail customer perspective, because wholesale transactions would offer more flexibility and less of the "portfolio" risks alluded to earlier. With wholesale transactions, the Company would not be locked into a multi-decade commitment to a specific type of fuel, or a specific heat rate. If it were to instead enter into shorter term contracts, it would have the flexibility to scale back its use of natural gas over time, or to change suppliers over time, moving to newer plants in the "out" years, if they have a better heat rate.

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This added flexibility would provide benefits that are somewhat like the benefits of a "CD ladder." Instead of buying a 20 or 30 year bond, an investor may instead buy multiple CDs with staggered maturity dates. This strategy offers greater flexibility, enabling the investor to "cash out" some of the CDs, in order to change their portfolio if this is warranted by changing circumstances.

To be clear, wholesale power purchases won't eliminate the risks associated with fossil fuels, since most sellers will insist on a floating price that is linked to the unit's actual fuel costs, or to a standardized measure of fuel costs, like the Henry Hub index of natural gas prices. Nevertheless, power purchases do offer some additional flexibility, which translates into the potential for reducing the fuel-related risks shouldered by retail ratepayers. Purchased power offers some a higher degree of flexibility, which can potentially enable the purchaser to minimize some of the risks of over reliance on fossil fuels. For instance, rather than being committed to burning natural gas for 20+ years, the Company can focus on PPAs with a duration of 10 years or less – providing the opportunity to switch to a different energy source if gas prices escalate more than expected.

In replacing the nuclear units, customers will benefit from an expansion plan that maintains a high degree of flexibility, rather than locking into a specific fuel source and heat rate, yet the Company's avoided cost analysis completely ignores the risks associated with fossil fuels, and the risks of over reliance on natural gas in the generation portfolio.

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No justification has been offered for this sudden lack of concern about these risks, which have not diminished or disappeared. To the contrary, the potential for sharply high natural gas prices continues to exist, and the environmental and political risks associated with carbon dioxide also loom on the horizon.

It is fundamentally inappropriate to ignore these risks when comparing scenarios that increase reliance on natural gas with ones that rely more on renewable energy sources like hydro, wind and solar power. Completely ignoring the difference in risks skews the analysis against QF energy, negating consideration of the benefits of being able to purchase power at a guaranteed fixed price.

Q. WHAT FUEL PRICES DID YOU USE TO DEVELOP YOUR AVOIDED ENERGY COST ESTIMATES?

A. I evaluated multiple scenarios, similar to the way SCE&G evaluated its V.C. Summer units. One scenario assumed natural gas prices gradually return to the historical trend line, then follow the trend line, as shown in this graph:

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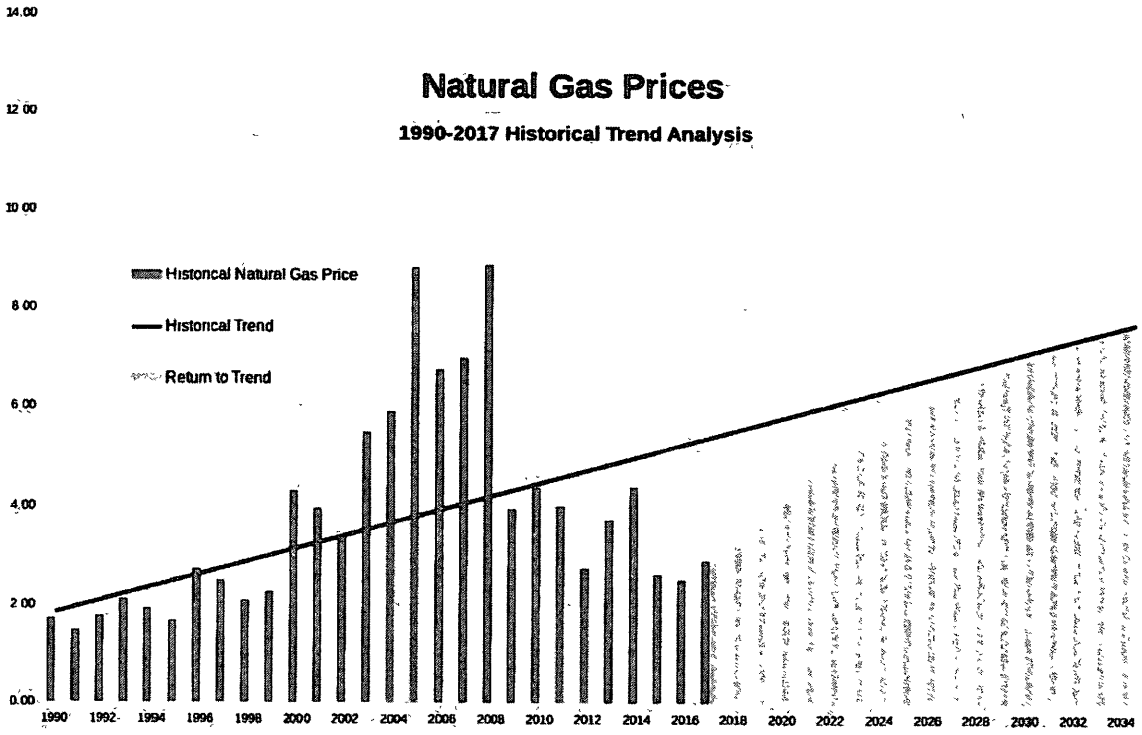

Another scenario was based upon the EIA's 2017 baseline fuel price forecast. As shown in the following graph, the EIA's 2017 forecast is similar to the trend-based scenario, but the EIA forecast is based upon a very detailed analysis of fundamental economic factors, shifting supply and demand conditions, changes in technology, growth exports of Liquefied Natural Gas, and the like. The EIA forecast is generally consistent with the return-to-trend analysis, but their forecast are sometimes a little above, and sometimes a little below, the smoother "Return to Trend" price assumptions.

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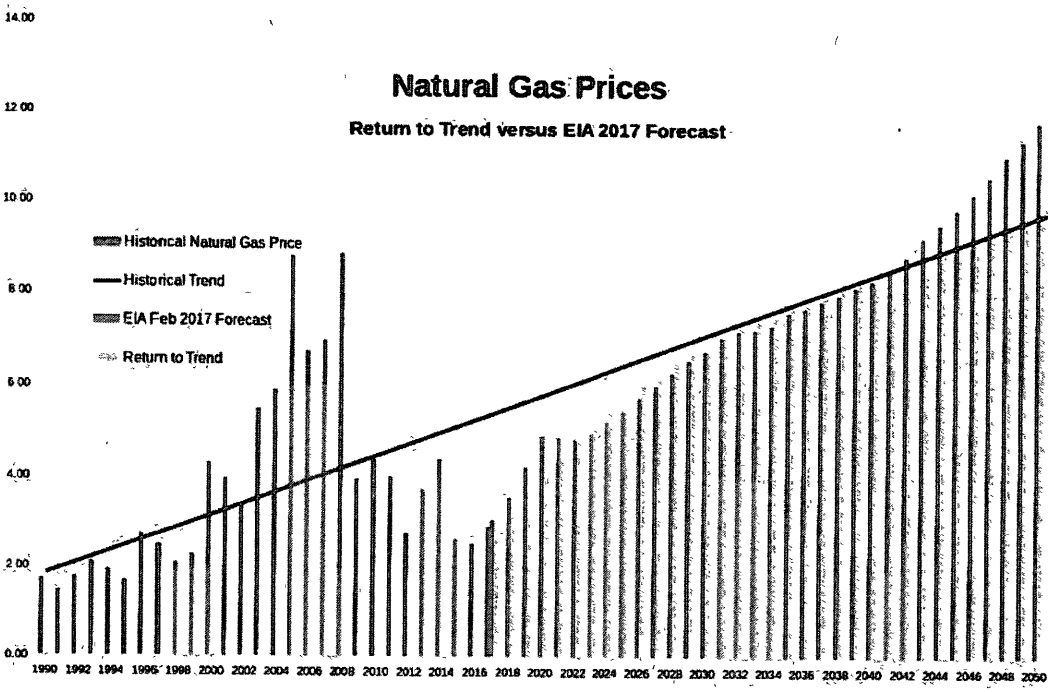

I bracketed these scenarios with a lower price scenario and a higher one, similar to the approach SCE&G used in its 2015 Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, as discussed above. The lowest price scenario was derived from SCE&G's Scenario 1 and the highest price scenario was derived from SCE&G's Scenario 3. I adjusted both scenarios to lower prices in the initial years, to reflect the 2015, 2016 and 2017 historical data, which wasn't available when SCE&G prepared its V.C. Summer evaluation. All four scenarios are shown in the following graph:

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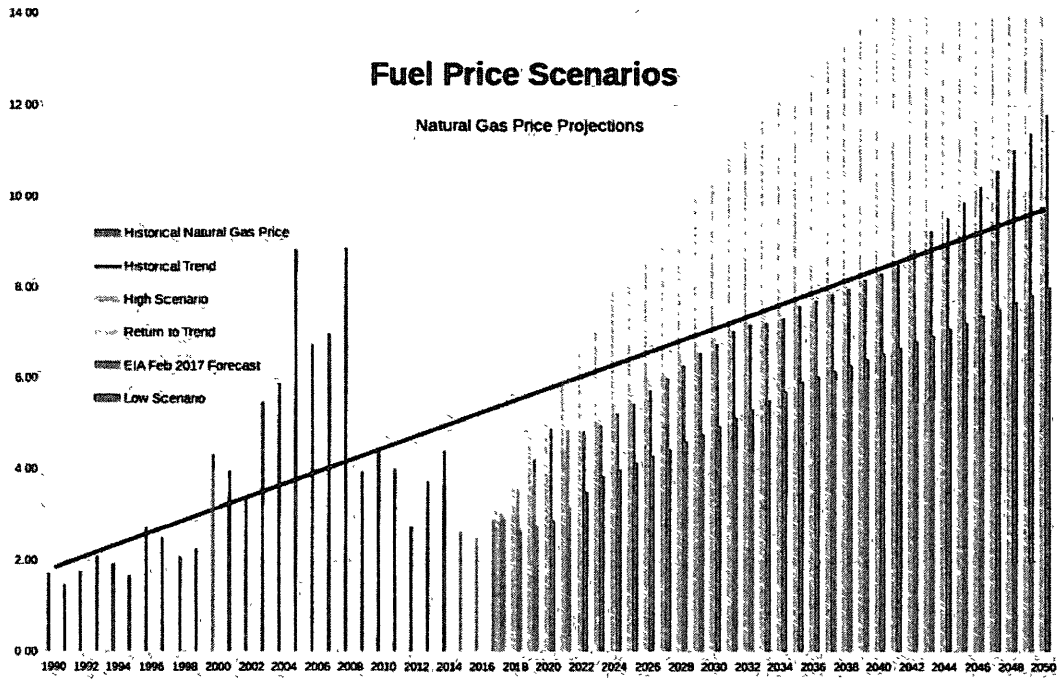

Q. DID YOU MAKE ANY OTHER ASSUMPTIONS RELATED TO FUEL COSTS?

A. Yes. First, I assumed fuel prices would eventually grow at the overall inflation rate (2%) except in the "High" scenario, where I assumed gas prices would increase 0.5% per year faster than the overall rate of inflation. Second, I assumed a heat rate of 6,500 BTU/kWh for the combined cycle unit and 9,750 BTU/kWh for the combustion turbine unit. These are forward-looking estimates which are consistent with what can be achieved with newly constructed generating units. Less efficient heat rates (and correspondingly higher

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avoided energy costs) would be applicable some of the Company's existing fleet of generating units. Third, I provided an allowance for non-fuel-related variable Operating and Maintenance costs of $2.50 per MWh for the combined cycle unit, $11.00 per MWh for the combustion turbine and $2.35 per MWh for the nuclear unit in 2016 Dollars, before applying a 2% per annum inflation factor. Fourth, I assumed nuclear fuel costs of 1.00 cents per kWh in 2016 Dollars, before applying a 2% per annum inflation factor. This is consistent with, or slightly lower than, the estimates reported by SCE&G in their June 2016 FERC avoided cost report under Subpart C, Section 210 of PURPA.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING RECOVERY OF FIXED ENERGY RELATED COSTS OVER DIFFERENT TIME PERIODS AND SEASONS?

A. As I will discuss later in my testimony, capacity-related fixed costs are appropriately attributed to peak hours and seasons. To some extent, the same logic holds for energy-related fixed costs, which should also be recovered disproportionately during daytime hours, when energy usage is relatively high.

In the Peaker Method, this is typically accomplished by disaggregating the production modeling output during different time periods and seasons, and by focusing on marginal energy costs, rather than average energy costs. Since marginal costs tend to be high during hours when energy usage is high, the Peaker Method allows fixed energy-related

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capital costs to be recovered on a granular, hour-by-hour basis, following the hourly variation in marginal energy costs. It should be noted, however, this procedure doesn't necessarily ensure that fixed costs are recovered in their entirety.[42]

A variety of different methods can be used to deal with this problem in the context of the DRR method. For my purpose here, I used a similar approach to achieve at least a minimal degree of granularity, and to ensure that all the energy-related fixed costs are taken into account. I first classified fixed costs in excess of the fixed costs of the Combustion Turbine as energy-related, and then took steps to ensure that energy-related fixed costs were largely recovered during times when energy usage is high, rather than at night, when energy usage tends to be lower.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING HOURS OF OPERATION?

A. Coal plants have traditionally been classified as baseload plants, and dispatched before gas-fired combined cycle plants, which have historically been classified as mid-range plants, while combustion turbines are classified as peakers and expected to be dispatched last. However the dispatch sequence can vary with changes in fuel prices and the age of each specific plant. In general, generating plants tend to be dispatched more frequently

[42] In practice, the results of the Peaker Method can sometimes understate costs, since there is no guarantee the energy cost estimates and capacity cost components will be internally consistent, or sum to the full incremental cost of building and operating a new generating plant – as they are theoretically supposed to.

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when they are first added to the system and less frequently as they get older, as newer, more fuel-efficient units are introduced to the resource stack. Similarly, gas prices have recently been very low relative to coal prices, causing less efficient coal plants to be dispatched higher in the generation stack (after newly built gas-fired combined cycle plants).

Although somewhat simplified, the approach I used is consistent with the way these different technologies are typically used over their economic life cycle, and it provides a straightforward way of comparing the cost of these different proxy units. However, it is helpful to realize the actual number of hours any given plant will be dispatched will vary as fuel prices change, and it will tend to decline as the plant ages.

I assumed a nuclear unit would be dispatched at the bottom of the generating stack, and its energy-related costs would be recovered during all 8,760 hours per year. I assumed a combined cycle unit would be dispatched in the middle of the stack (below the combustion turbine) and its energy-related fixed costs would be recovered over 5,110 hours per year.[43] Finally, I assumed a combustion turbine would be dispatched last, since it has the highest variable costs. In actual practice, a CT may almost never be dispatched, in which case its energy-related fixed costs will be recovered over very few hours, and

[43] Spreading the energy-related fixed costs over 5,110 kWh per KW of capacity is similar to assuming the Combined Cycle unit will be dispatched approximately 58% of the time, which is reasonably consistent with the overall system load factor.

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the resulting level of avoided energy per kWh might be quite a bit higher than what I have presented here.

Q. WHAT CONCLUSIONS DID YOU REACH CONCERNING AVOIDED ENERGY COSTS PER KWH?

A. Avoided energy costs vary widely, depending upon the technology and the future course of natural gas prices. Looking first at a Combustion Turbine, the levelized avoided energy costs (including fuel and variable O&M) will range from less than 4 cents per kWh to more than 11 cents per kWh, depending on the time frame and assumed level of gas prices. This is shown below:

Combustion Turbine Energy-Related Cost per kWh/Year	Natural Gas Price Scenario			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.98 ¢	5.13 ¢	4.65 ¢	5.53 ¢
2022 - 2026 Levelized	5.13 ¢	6.40 ¢	6.55 ¢	8.80 ¢
2027 - 2031 Levelized	6.09 ¢	7.79 ¢	7.99 ¢	11.05 ¢

The sensitivity to the different fuel price scenarios isn't as extreme with the Combined Cycle plant, since it has a better heat rate (burns less fuel) and because the avoided

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energy costs include some energy-related fixed costs (which don't vary with fuel prices). This greater stability can be seen below:

Combined Cycle Energy-Related Cost per kWh/Year	Natural Gas Price Scenario			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.03 ¢	3.78 ¢	3.45 ¢	4.02 ¢
2022 - 2026 Levelized	3.72 ¢	4.54 ¢	4.62 ¢	6.07 ¢
2027 - 2031 Levelized	4.27 ¢	5.38 ¢	5.49 ¢	7.47 ¢

Together, these avoided energy cost estimates provide a benchmark for comparison with the Company's proposed QF energy rates. As shown, this comparison reveals that the proposed QF rates are significantly less than costs that will be avoided if QF power is purchased to meet retail customer needs, rather than running the Company's existing fleet of generators. Most of the existing generators have heat rates that fall in between the heat rates I used for the Combustion Turbine and Combined Cycle cost estimates.[44]

[44] If a new generating unit is expected to be dispatched less than approximately 1,700 hours a year, the benefit of the lower installed cost of the CT outweighs the burden of its higher heat rate and fuel costs.

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Proposed QF Tariff Changes

Q. THE COMPANY IS PROPOSING SEVERAL QF-RELATED CHANGES IN THIS PROCEEDING. CAN YOU BRIEFLY DESCRIBE THESE CHANGES?

A. Yes. The Company is proposing major changes to its QF tariffs that would individually and cumulatively have the effect of sending fewer, less precise price signals to independent power producers, and discouraging QF investment.

The first proposal is to stop paying competitors for the use of their energy-generating capacity and to eliminate any compensation for the reliability benefits that QF generators provide during peak usage times. Regardless of the technical arguments for and against this proposal, it is worth noting that it would be intensely and unlawfully discriminatory, since SCE&G would continue to be paid for the use of its energy-generating capacity, unlike its competitors. In addition, SCE&G would continue to be fully compensated for the reliability benefits its generators provide during peak usage times, while its competitors would not receive any compensation for the analogous benefits they provide.

The second proposal is to: "limit the availability of its PR-2 Rate to solar QF's only and to offer separate rates for solar and non-solar QF's in its PR-1 Rate."[45] This seemingly innocuous proposal would have several ill effects. Whatever the intent, establishing an arbitrary distinction between solar and non-solar technologies could have the unintended

[45] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 7.

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consequence of creating barriers to competition between these two categories. Furthermore, segregating competitors on separate tariffs that can potentially have different terms and conditions, as well as different rates, may have the effect of skewing the competitive environment in favor of the firms operating on one tariff or the other. This particular proposal also has the effect of creating regulatory uncertainty at the worst possible time – when rapid innovation is taking place that will blur the lines between solar and non-solar technologies.

Making PR-2 a solar-only tariff would also deprive other kinds of QFs of the benefit of standard rates (the PR-1 standard offer tariff, which is not solar-only, is limited to very small generators (100 kW or less)). This would discourage significant investments in non-solar technologies like hydro, biomass and wind.

The proposed "solar-only" rates and methodology are also a bad fit for projects that generate electricity using solar technology but combine it with utility-scale lithium-ion batteries or some other method of storing electricity. This is in part because the Company's assumptions about solar QFs' output profile—assumptions on which the calculation of much lower avoided energy and zero avoided capacity costs are based—simply don't hold when a solar project can use storage to shift the times when it puts power on the grid. These hybrid investments enable competitors to avoid sending power onto the grid at times when a surplus exists, or the power is not as valuable to users, storing it on site, so they can send market the power at a later time, when it is more

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valuable. This has the potential to benefit firms that invest in these innovative technologies, as well as society as a whole – providing users with the benefit of low-cost, abundant solar energy even when the sun isn't shining. The existing tariffs do not provide strong enough price signals to optimize these types of investments, but at least they provide some incentive for investing in storage. In contrast, the proposed solar rates provide no incentive whatsoever for investing in storage, since they pay all QF's based upon a generic profile, rather than reflecting the actual timing of the energy provided by each individual QF.

The third proposal is to reduce the frequency with which QF rates are updated and refined. This would further enhance the Company's monopoly power, and enable it to more tightly control the process by which QF rates are established, including how often and when rate changes can occur:

> SCE&G also proposes to its update PR-2 Rate going forward only on an "as needed" basis instead of twice a year.[46]

The decision whether a rate change is "needed" would be decided by the Company, rather than ORS or the Commission. Needless to say, it is easy to imagine circumstances where the independent power industry might see a compelling need for refinement or updating of the QF rates while the Company might prefer the status quo and thus refuse to acknowledge that new QF rates are "needed."

[46] *Id.*

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Q. DO ALL OF THESE PROPOSALS HAVE SIMILAR EFFECTS?

A. Yes. Regardless of the specific details or underlying rationale, if they are approved, they will have similar economic impacts:

- Independent power producers will be discriminated against.
- Competitive risk-taking and innovation will be discouraged.
- The Company's monopoly power will be enhanced.
- Customer exposure to fossil fuel-related risks will increase.
- Renewable energy sources will be suppressed.
- Customers will not gain the full benefit of robust competition.

Q. ARE THERE SOME FUNDAMENTAL REASONS WHY THE COMMISSION SHOULD ENCOURAGE COMPETITION?

A. Yes. Experience has repeatedly demonstrated that, regardless of the goal, government control over economic sectors rarely works as well as market forces to achieve the same goals. Pervasive system-wide failures in places like the Soviet Union, Cuba and Venezuela have vividly demonstrated how poorly government control over the economy works in practice. The experience with more limited controls over specific sectors of the economy is not as bleak, but nevertheless it points to the benefits of effective competition.

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Some observers might point to China as evidence to the contrary, but in reality it provides yet another example confirming the same truth. Under Chairman Mao, China fell farther and farther behind Taiwan, although that island had far fewer natural resources. In more recent years, enormous economic gains have been experienced in China precisely because intense monopoly control over the economy by the Communist Party was relaxed, and independent firms were allowed to compete. A proliferation of individual firms (often owned and controlled by individual local governments) began to vigorously compete with each other (and with overseas firms).

As competition increased and monopoly control diminished, competition has begun to play a larger role in determining investment decisions and economic outcomes. While a high degree of government control still exists in China, most people have has benefited as competition has expanded. Individual firms and local communities are being allowed to make independent investment decisions, and they are allowed to share in more of the benefits of their success (and forced to bear more of the burdens of their failures). This has led to much higher levels of investment, innovation and risk-taking throughout the Chinese economy, which explains why we are seeing such rapid growth and improvement in living standards.

While this discussion may seem like a digression, it actually goes to the heart of why I believe the Commission should reject all of the Company's anti-competitive proposals in this proceeding. The public interest is advanced when it is feasible to increase reliance

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on competition and market-driven economic outcomes, as it is in this proceeding. Among other reasons, competitive processes tend to be more flexible and capable of quickly adapting to changes circumstances and technologies, and they are more capable of inspiring and fostering innovation, creativity, and hard work. More fundamentally, when many different minds are simultaneously trying to solve a problem, and are willing to take different risks, more ideas are generated, more ideas are tested, and there are more opportunities to learn what works and what doesn't.

Conversely, when a single monopoly decision maker controls all of the investment decisions in a particular sector or market, these benefits tend to be lost, and there is a much greater risk of catastrophic failure. Where economic power is intensely concentrated, a single bad decision or judgment call – however well intentioned – can have far-reaching consequences for all concerned.

This is not intended as a criticism of public utility regulation, or a suggestion that regulated monopolies can be completely replaced with competition. My entire 40+ year career has been focused on helping regulators do their jobs as well as possible. Based upon my experience, I am fully convinced that the electrical distribution system (and, to a lesser degree, the transmission system) is a natural monopoly, and that on the whole, rate base regulation has been a highly successful way of handling these natural monopolies.

However, many economists (myself included) have long argued that we can and should

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improve upon this success story by introducing competition where this is feasible. PURPA is one of cases where government policy makers decided to allow competitive risk taking and innovation, while continuing to regulate remaining parts of the industry. The Commission should use this opportunity to increase competitive pressures in the electric utility industry, and to reduce the need for ratepayers to bear the risks of new generating capacity.

Q. GIVEN THE LIMITED TIME FRAME OF THIS PROCEEDING, SHOULD THE COMMISSION DEFER TO THE COMPANY'S JUDGMENT, ESPECIALLY SINCE THESE ARE HIGHLY TECHNICAL ISSUES?

A. No. This fuel proceeding is being conducted on a highly expedited schedule which does not provide enough time to investigate or even discuss all of these issues raised by SCE&G's filings in complete detail. And in light of this schedule it would be highly inappropriate to give the Company the benefit of the doubt concerning these issues. In my opinion, it would be far preferable to address these issue in a stand-alone proceeding with reasonable time frames and an opportunity for all parties to fully develop the record. This is especially true since the Company's proposed changes are coming at a pivotal time in the transition toward renewable energy sources – a time when rapid innovation and massive investment risks are being undertaken by new entrants. It would be a serious mistake to rush the adoption of these types of changes without adequate study, especially since these changes would shift some policies 180 degrees away from the direction we

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should be heading.

For instance, the Commission should be moving in the direction of requiring stronger, more precise price signals to help guide competitive investment decisions. Yet, the Company is proposing the opposite: to eliminate the capacity rate, and to make the rest of solar rate structure even less granular than it is now.

Q. WHY ARE STRONGER, MORE PRECISE PRICE SIGNALS PREFERABLE?

A. Prices are vital to the success of competitive markets. They help guide both customers and suppliers. They encourage increases in supply where it is most needed, and they indicate where investment should be reduced or eliminated.

The Company's proposals to weaken price signals will have the effect of blocking these societal benefits. In fact, by eliminating all price signals that indicate when power is most valuable, and by eliminating all payments for the reliability and capacity benefits offered by solar QF's, the proposed solar-only tariffs would discourage solar investments, reduce the incentive for innovators to improve the reliability of their generating system, and eliminate any incentive for competitors to find ways to inject their power into the grid during times when it is most valuable.

Removing price signals, updating QF rates less frequently, and making them less precise are all movements in precisely the wrong direction. Adopting any of these changes at

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this time would be a particularly unfortunate step for the Commission to take at a time when we are seeing many billions of dollars of new investments flowing into renewable energy technologies worldwide. South Carolina is currently at the leading edge of this worldwide trend, and it is currently benefiting from innovations and investment risk taking by independent power producers who have been attracted by the current regulatory system, which allows them to freely enter the market and compete with the incumbent utilities.

To continue to get the full benefit from these trends, it is important to not erect new barriers to competitive entry, to not create a lot of unnecessary regulatory uncertainty, and to not adopt policy changes that are biased against competitive investments and in favor of rate base investments. Discouraging competitive risk taking will eventually lead to new generating units being put into its rate base, and customers will inevitably shoulder some of the risks associated with those investments. Risks that are partly borne by customers include many of the adverse consequences of poor technology choices, schedule delays, cost over-runs, unexpected price changes, and failed innovations. In contrast, none of these risks are borne by customers when power is obtained from independent power producers, who are paid for output at long-term fixed prices.

It is all too easy to overlook these risks, because they are simply "baked in" to the incumbent utility's retail rates. The adverse risk outcomes are rarely as visible as the problems encountered with V.C. Summer Units two and three. A more typical example

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is what happened with Duke Energy's Cliffside 6 coal fired generating unit. This costly unit was planned and constructed based upon fuel forecasts that have subsequently proven to be inaccurate. With changes in the relative price of coal and natural gas, the huge investment in advanced coal technology used at the Cliffside plant no longer appears to be as attractive as it must have seemed when it was chosen in lieu of much less costly, ordinary natural gas-fired combined cycle units.

Technology innovations and investment decisions that seem attractive at the time they are made will often seem less attractive in hindsight. I am not criticizing Duke Energy for betting on a high technology coal plant just before an unexpected era of very low gas prices that wiped out any benefit from this risky investment, any more than I am criticizing SCE&G for betting on nuclear power. My point is simply to remind the Commission that there is a sharp difference between what happens when customers bear these risks and what happens when a QF does.

The Commission can encourage competitive investment by providing independent power producers with stronger, more precise QF price signals. Improved price signals will help them make better decisions concerning where to risk their capital, what specific technologies to use, and what innovation risks to take. This will also put them in a better positions to decide how to respond to future changes in economic conditions and market opportunities, before they emerge. To be clear – I am not suggesting the Commission should become involved with these types of decisions. Rather, I'm suggesting the

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Commission should remove the regulatory barriers to sound decision making. Strong, accurate price signals encourage better decisions, which improves the investment climate and leads to better societal outcomes.

Q. CAN YOU RELATE THIS DISCUSSION OF MORE PRECISE PRICE SIGNALS TO THE COMPANY'S RATIONALE FOR PROPOSING TO LOWER SOLAR RATES AND ELIMINATE CAPACITY PAYMENTS?

A. Yes. The Company claims avoided costs are different for solar and non-solar QF's:

> SCE&G must separate solar QF's from non-solar QF's in order to pay each type of QF the correct avoided costs. As more and more solar generation facilities interconnect with SCE&G's system, the benefit of each additional solar generation facility to the Company's system is diminished. SCE&G performed a study titled "Avoided Energy Cost Methods Study for Solar QF's" ("Methods Study") to measure this effect and it is attached to this testimony as Exhibit No. __ (JML-3).[47]

To the extent there is merit to this line of reasoning, the best solution is not to set different rates for solar power, or to arbitrarily assume all solar generators have the same output profile (they don't) or to pay the same rate to solar generators every hour of every day despite the fact that the avoided costs vary widely depending on the time of day and day of the year.

The correct approach is to go 180 degrees in the opposite direction – to make the QF rate

[47] *Id.*

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structure more precise, so that differences in output from different technologies, or different generators are automatically reflected in the payments they receive. By moving in the direction of more pricing precision, so that QF rates reflect hour-by-hour differences in the value of power to a greater extent, each QF will receive a different aggregate level of payment, depending on when its output is delivered to the grid. This reform would more precisely match QF rates to avoided costs, and would ensure greater fairness to different types of generators. It would also provide better, more precise price signals to help guide investment decisions, especially with respect to solar plus storage. If the QF is paid more to inject power into the grid at times when the power is most valuable, this will support better decision making concerning how much to invest in generation and how much to invest in storage in solar + storage configurations.

More precise QF price signals will become increasingly beneficial to society as solar grows into a larger share of the overall generation mix. It is readily predictable that in future years, power generated at during the noon hour will not be as valuable as power generating an hour or two later in the day. Power consumption sometimes tends to dip during the lunch hour, while solar output tends to reach its maximum during the middle of the day. The air conditioning load also tends to extend farther into the afternoon beyond the point of maximum solar output, due to the cumulative effect of heat accumulation within buildings over the course of the day. Accordingly, an accurate analysis of avoided costs in five or ten years will show lower costs in the middle of the

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day than later in the afternoon. With accurate QF rates reflecting this evolving cost pattern, solar generators would have an incentive to add storage as the "duck curve" emerges. With strong, precise price signals, both society and the QF would benefit by taking advantage of the opportunity to store power in the middle of the day, and send it to the grid when it is more valuable, later in the afternoon or early evening.

Q. EARLIER IN YOUR TESTIMONY YOU MENTIONED HOW FIXED COSTS RELATE TO ENERGY COSTS. CAN YOU ELABORATE ON THESE CONCEPTS, AS THEY RELATE TO IMPROVED PRICE SIGNALS?

A. Yes. With a more sophisticated rate design that closely aligns with hourly and seasonal variations in avoided energy and capacity costs, all types of QF's will be treated fairly, each type of QF will be paid the right amount, and all types of competitors will be provided with an appropriate – but not excessive – incentive to invest in storage technologies. All of this will further improve societal outcomes – most obviously by enabling abundant, low cost solar energy to be used in the late afternoon, early evening, and early morning, if the energy is needed, or is more highly valued, during those times.

Q. IF AVOIDED CAPACITY COSTS ARE MOSTLY FIXED COSTS, CAN YOU EXPLAIN HOW THESE COSTS BE TRANSLATED INTO DIFFERENT RATES AT DIFFERENT TIMES AND DURING DIFFERENT SEASONS?

A. Yes. However, before answering this question in detail, I should mention that the

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relationships between fixed costs and prices, as well as the specific problem of how best to recover "capacity-related" avoided costs under PURPA are surprisingly complex issues, which can easily become confusing. The pricing issues are intertwined with subtle distinctions between capacity costs and fixed costs which can best be explained by first explaining how joint and common costs are recovered under competitive conditions. In turn, this competitive example provides clear guidance concerning the optimal way of recovering capacity-related costs during different hours of the day, and days of the year.

Although the issues are quite complex, they are well worth exploring in detail, since they are of pivotal importance to the future of the solar industry. In the context of a regulated monopoly, it wasn't always necessary to be concerned about setting precise price signals, or resolving the best way to recover fixed costs through per-kWh prices. Typically, the benefits of administrative convenience outweighed any need to be concerned about setting optimal, or even very accurate prices. However, with QF prices, the rates set by this Commission will influence billions of dollars of investment. Improving these price signals will help improve those investment decisions, avoid excessive amounts of investment (the boom and bust phenomena that occurs in some markets) and help avoid or overcome the problems SCE&G identified in the studies it submitted in support of its proposed QF tariff changes.

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Q. YOU'VE MENTIONED SEVERAL TYPES OF COSTS. SOME OF THESE TERMS ARE LESS FAMILIAR THAN OTHERS. CAN YOU PROVIDE SOME DEFINITIONS?

A. Yes. In economics, the most fundamental and important types of costs are fixed cost, variable cost, total cost, average cost, marginal cost, incremental cost, and stand-alone cost. All of these are integral parts of economic theory – along with other, more specialized cost concepts, including sunk, direct, joint, and common costs. All of these cost concepts are significant to the issues in this proceeding.

Fixed costs do not change with the level of production, during the planning period or "run" under consideration. **Variable costs** change directly (but not necessarily proportionately) with the level of production. It should be noted that the exact same item might be a fixed in the short-run and a variable in the long-run. Together, fixed and variable costs constitute **total cost**, which is the sum of all costs incurred by the firm to produce a given level of output. Dividing the total cost of producing a given volume of output by the total number of units produced, one can calculate **average total cost.**

Short-run costs are those which arise in situations where most costs are fixed. In contrast, **long-run costs** are those calculated under the assumption that many, if not all, costs are variable, and relatively few costs are fixed or sunk. The classic long-run concept is sometimes known as a "scorched earth" approach – that is, no pre-existing plant is considered in the analysis. Instead, the firm is free to build precisely the size and type of

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plant which best fits the assumed output level. However, even in the long-run some aspects of the production process are typically assumed to remain inflexible – like the technology the firm uses, or the state or region where the firm operates.

Incremental cost is the change in total cost resulting from a specified increase or decrease in output. In mathematical terms, incremental cost equals total cost assuming a specific increment of output is produced, minus total cost assuming the increment is not produced. Incremental cost is often stated on a per-unit basis, with the change in cost divided by the change in output. Incremental cost can vary widely, depending upon the increment of output under consideration. If the entire increment from zero units to the total volume of output is considered, incremental cost is identical to total cost. Similarly, where the increment ranges from zero to total output, incremental cost per unit is identical to average cost per unit for that volume of output. Because a wide variety of different increments can be specified, a wide variety of different incremental costs can be calculated. Thus, in considering any estimate of incremental cost it is crucially important to determine whether or not the specified increment is relevant to the issues at hand.

Marginal cost is the same as incremental cost where the increment is extremely small (e.g., one unit) and the cost function is smooth and continuous. In mathematical terms, marginal cost is the first derivative of the total cost function with respect to output (the rate of change in total cost as output changes).

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Common costs are incurred when production processes yield two or more outputs. They are often common to the entire output of the firm but can be common to just some of the outputs produced by the firm. An increase in production of any one good will tend to increase the level of common costs; however, the increase will not necessarily be proportional. The costs of producing several products within a single firm may be less than the sum of the analogous costs that would be incurred if each of the products were produced separately (this is referred to as economies of scope).

Joint costs are a specific type of common cost—they are incurred when production processes yield two or more outputs in fixed proportions. A classic example arises in the joint production of leather and beef. Although cattle feed is a necessary input for the production of both gloves and hamburgers, there is no economically meaningful way to separate out the feed costs that are required to produce each. If the quantity of leather and beef is reduced, there will be a savings in the amount of cattle feeding costs, but it is impossible to say how much of this change in cost results from the change in the quantity of leather, and how much from the change in the quantity of beef.

Q. WHY ARE JOINT COSTS RELEVANT TO THIS ISSUES IN THIS PROCEEDING?

A. In the electric utility industry, the cost incurred in creating the capacity (or ability) to generate, transmit, or distribute electrical energy are joint across time. To draw a

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comparison, there is a clear parallel between the cost of cattle feed and the cost of generating capacity. Expenditures that increase the quantity of beef invariably tend to increase the quantity of hides that are available, as well. The specific quantities may not be identical, and it is conceivable that some of the hides might get thrown away, but the production proportions themselves tend to be inextricably linked and highly stable (it is not easy to vary the proportion of beef and hides). Similarly, an investment that results in the capacity to generate a certain number of kWh of electrical energy from 2 pm until 3 pm on Mondays will very likely result in the ability to generate the exact same number of kWh of energy from 2 pm until 3 pm on Tuesdays, and the rest of the week, as well.

In fact, the problem of joint costs across time is so pervasive, it is easily overlooked. Once money is spent on the ability to generate electricity on a hot summer afternoon, the same capability exists and is available during cool spring afternoons, and cold winter mornings, as well. Depending on the specific technology, there may be limitations and differences in the engineering proportions, but the joint cost concept still applies. For instance, due to temperature differences, a combined cycle plant may provide more energy generating capacity during a cold winter morning than during a hot summer afternoon – the proportions are not precisely one-to-one, but they are nevertheless relatively fixed, and cannot easily be varied.

The fact that fixed costs do not (by definition) vary with output, and because of the existence of a pervasive joint cost problem across different time periods, QF rates involve

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a situation where many costs cannot accurately and easily attributed to a specific hour of the year, or a specific kWh. While it is sometimes argued that all capacity related costs should be attributed to the single highest peak hour of the year, upon further thought, most knowledgeable observers realize this is not, and cannot be, the correct pricing solution. By this logic, a supplier would attempt to charge an extremely high price during the one highest peak hour of the year, and it would charge nothing during the remaining hours. Upon reflection, it is obvious that many customers would not be willing to pay this extremely high price (it would be something on the order of $60 per kWh), and so many users would conserve, or stop using electricity during that one hour. If even a few users react this way, usage would drop sharply, and this hour would no longer be the peak hour – the highest rate of usage would simply occur during a different hour.

Q. WHAT DOES ECONOMIC THEORY TELL US ABOUT HOW JOINT COSTS ARE RECOVERED IN COMPETITIVE MARKETS?

A. Joint costs create a challenging puzzle for economic theory: it is not immediately obvious how joint costs are recovered in competitive markets, since they do not show up in the marginal costs which normally explain how prices are determined. The solution to this puzzle, which was discovered in the early 1900's, sheds light on how more precise capacity rates can be developed, as well as yielding some useful insights into why the Company's argument against making capacity payments to solar generators is flawed.

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Decades before the joint cost puzzle was solved, economists had figured out that prices tend to equilibrate to a level that is equal to marginal cost. In fact, in situations where firms are accepting a market-determined prevailing price, marginal cost is the key to understanding how that prevailing price is established. Among other insights gleaned from this analysis is that average cost is much less important than marginal cost.

A classic example is a wheat farmer. A wheat farmer has no control over the weather, and no control over the price of wheat, which is decided through nationwide forces of supply and demand. Hence, he concentrates on optimizing those aspects of his production function that he can control (deciding how many acres to plant, what crop rotation system to use, what seed to plant, how much fertilizer to use, how much to irrigate) in an attempt to maximize profits.

Like all competitive firms, wheat farmers make these types of decisions based on an analysis (whether explicit or implicit) that is tightly linked to marginal cost, rather than average cost. The firm increases each factor of production beyond the point of diminishing returns, until the point where the marginal revenue product associated with each input is equal to marginal resource cost of that input. While each firm makes these decisions independently, their individual decisions collectively lead to a convergence of industry-wide prices and marginal costs. In fact prices will exactly equal the industry-wide level of short-run marginal cost if the industry is in short-run equilibrium, and prices will equal long-run marginal cost if the industry is in long-run equilibrium. In

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equilibrium, every firm's marginal cost will exactly equal every other firm's marginal cost, despite wide differences in their individual circumstances, like the fertility of their soil, the types of equipment they use, and other details of their production function, and despite the lack of any coordination in their individual production decisions.

Because joint costs do not directly vary with the output of any one product, they are an exception to this general pattern, and it is not self-evident how they are recovered from customers. Among other insights that can be gleaned from solving the joint cost puzzle is that the general equilibrium conditions that were just described are not achieved exclusively by costs being adjusted to match prices. To some extent, the process also works in the reverse direction: prices also tend adjust to the level of marginal costs incurred by the typical firm. Decisions made by both producers and consumers are important in establishing prices in competitive markets. Succinctly stated, the interaction of both supply and demand determines what costs are incurred by producers and what prices are paid by consumers.

Q. WHAT IS THE SOLUTION TO THE JOINT COST PUZZLE?

A. The solution is straightforward, but not obvious: in competitive markets, relative levels of value – or benefits – largely determine the share of joint costs recovered from each of the joint products. If two products are jointly produced, the most valuable product, or the one that receives the largest benefit from the joint production process, will pay the largest

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share of the joint costs. The least valuable product, or the one that receives the smallest benefit from joint production, will pay the smallest share.

Recall that joint costs are incurred when production processes yield two or more outputs in fixed proportions. Two classic examples are the production of beef and hides and the production of cotton and cottonseed. The costs of raising and slaughtering cattle are part of a joint production process that produces both meat and hides, in relative proportions than cannot easily be adjusted by the cattle farmer. Similarly, cotton and cottonseed oil are both part of a joint production process, in proportions that cannot be easily adjusted.

The cost of fattening and slaughtering cattle are paid by consumers of both beef and hides, while the cost of growing and harvesting cotton are recovered from consumers of both cotton and cottonseed oil, in proportions that depend on the relative value of each of the joint products (not their respective marginal costs). For example, if hamburger is not highly valued (because consumers don't particularly like hamburger, or they prefer chicken or seafood), but leather is highly valued, a surprisingly large fraction of the cost of cattle feed may be borne by the purchasers of leather goods. Similarly, if the purchasers of gloves are willing to pay more for leather gloves than for cloth gloves, they may end up paying a relatively large share of the cost of cattle feed while the purchasers of cotton gloves may pay a relatively small share of the cost of growing cotton (and consumers of cottonseed oil may pay a larger share than might otherwise be expected).

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Once the solution to the joint cost problem is explained, many people find it intuitively logical and reasonable. The purchasers of both leather gloves and hamburgers both benefit from the joint cattle feeding and slaughtering process, so it makes sense that both will contribute to the joint production costs. Similarly, the demand for both beef and leather products is strong, so it seems logical that market forces would lead consumers of both sets of products to contribute toward the joint costs of raising and slaughtering cattle.

Different customers pay different amounts, depending on how much benefit they derive from the joint production process. Those consuming the most highly valued products (for which demand is strong) will pay the largest share of the joint costs, while those consuming the least valuable products (for which demand is weak) will pay the least. This principal applies not only to the distinction between beef and hides, but also to different types of beef, or different sections of the hide. A customer that purchases hamburger will end up paying less per pound toward the joint costs of cattle production than one who purchases standing rib roast or filet mignon.

Q. WHAT ARE THE IMPLICATIONS OF THIS ANALYSIS FOR THE ISSUES IN THIS PROCEEDING?

A. Electrical energy production is a joint product when viewed across time. Capacity used to generate electricity during the peak daytime hours is also available for use during other hours. Under competitive conditions, when costs are joint across time, they will not be

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borne exclusively by users in any single time period. We can go beyond this to also note that the joint cost recover will not be equal in every hour of the day or year. To the contrary, more of these fixed costs will be borne by users in the peak hours – when demand for electricity is strongest, and most users value it especially highly. A smaller share of the capacity costs will be incurred late at night, and during the off-seasons like spring and fall, when the weather is mild and the demand for electricity is relatively low.

The joint cost recovery pattern observed in competitive markets is highly significant, and it can appropriately be used by the Commission to help guide the way it sets QF capacity rates. Following the standard solution – recovering more capacity costs at times when demand is high, yet also recovering a small share of these costs at times when demand is low – provides economically sound price signals that will help guide competitive investment decisions.

Q. CAN YOU CLARIFY WHY A SOLAR GENERATOR SHOULD BE PAID MORE THAN THE SHORT RUN MARGINAL COST OF ENERGY?

A. In markets where joint costs are not significant, prices tend to equilibrate to marginal cost. However, in markets (like electricity) where joint and common costs are pervasive, total costs cannot be recovered using pure marginal cost based prices. Instead, prices must include a markup above marginal cost, to provide a mechanism for the recovery of joint and common costs. The cost recovery pattern is clear and consistent across all types

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of markets where joint costs exist: recover the variable direct costs incurred by producers – short run marginal costs – plus a contribution toward their otherwise unrecoverable indirect, joint and common costs. The amount of that contribution will vary depending on market conditions, the strength of demand for different products or services, and the level of marginal costs incurred by a specific firm relative to other firms. Producers are paid based upon the value of what they produce, not based upon their internal cost characteristics. A firm with high marginal costs (and low fixed or joint costs) might receive very little markup above their marginal cost. Another firm with very low marginal costs but high fixed costs, would be paid an equivalent price for their production, but that price would involve a large markup above their marginal cost.

In competitive markets, there are market forces that push prices toward short-run marginal cost. However, there are other market forces that will push prices toward a long-run equilibrium level that exceeds this level, if this is necessary to ensure that each price includes an adequate contribution toward joint and common costs, so that a typical firm can recover its total costs, including the costs associated with long-term capital investments. In competitive markets, demand conditions help determine the extent to which the firm's costs are recovered from specific products or services, and the extent to which its costs are recovered from specific customers or customer groups.

More specifically, if purely marginal cost-based prices would not be sufficient to ensure adequate total cost recovery, prices will instead equilibrate (in the long-run) toward levels

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that exceed marginal cost by the amount necessary to enable the typical firm to recover its joint and common costs. Significantly, this demonstrates that competitive prices are not purely a function of marginal cost.

By analogy, under competitive conditions, the fact that a particular firm has marginal costs of zero would have no relevance to the revenues it would obtain. The price it is paid is based on the interaction of supply and demand for the market as a whole. If the product it produces is valuable, it will be paid for that value, even if its marginal cost is zero. Consider again the example of cotton and cotton seed. A firm that spins cotton into cotton cloth may consider the seeds a mere byproduct – something that costs them nothing, since they came for free with the cotton they purchased from farmers. Nevertheless, if other firms find a valuable use for cotton seeds (converting them into oil), the amount paid for the seeds will be purely a function of their value when turned into oil – and the payment received by the cotton mill will represent pure markup over their marginal cost, which is zero in this example.

The same principle applies to the production of electricity. A solar generator should be paid for the value of the electricity it provides, as well as the reliability benefits it offers by producing power at times when electricity is highly valued and needed by users. In turn, this provides a cost recovery mechanism that enables the generator to recover some the fixed costs of its investment – with the highest revenues being generated during hot summer afternoons, and lower revenues during a cool fall afternoon. Similarly, with

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appropriately structured QF capacity rates, firms that invest in storage technology will have the option to shift some of their output from hours when electricity is less valuable to hours when it is more valuable. Accurate, time-sensitive price signals will encourage a market-driven response to those price signals, encouraging investments in storage, and helping independent power producers with storage to determine how to use their storage capacity to gain the maximum benefit for them and for society.

Q. ARE YOU SUGGESTING THAT MARGINAL COSTS ARE IRRELEVANT?

A. None of this discussion in any way suggests that marginal (variable) costs are irrelevant. Recall that under competitive conditions both supply and demand are important. Producers respond to prices, and prices are determined by market forces, with the interaction of supply and demand determining the relative share of joint costs that are provided from the joint products. In this context, that means that users of electricity during different hours will make different contributions above marginal cost.

In general, the amount paid during specific hours will vary depending on the strength of demand during those hours, and the amount received by specific producers will depend on their willingness and ability to meet market demand during those hours. It is during hours with the strongest demand – and in that sense, the greatest benefits from the joint production process – when the greatest share of joint costs will be borne. In turn, this determines what share of the joint costs are recovered from different users, but all users

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of electricity end up contributing to the recovery of the joint costs.

To the extent different types of users have different usage patterns, they will make different contributions. For instance, an industrial user that consumes a lot of electricity late at night, and especially if it is willing to be interrupted during peak hours, will pay relatively little per kWh for its electricity, compared to a retail store that only operates during daytime hours and uses a lot of air conditioning on hot summer afternoons, when the demand for electricity is high.

Similar disparities exist on the production side of the supply and demand equation. Different competitors may use different technologies to produce essentially the same product, in which case they will have different cost functions, and incur different levels of marginal cost. The revenues received by firms with low marginal costs and high levels of fixed or joint costs can still compete with firms that have a higher level of marginal costs and lower fixed or joint costs. In both cases, prices may involve a markup above marginal cost to recover fixed or joint costs, but the magnitude of that markup may will depending on their particular cost function and circumstances.

In the electrical context, we can anticipate that generators with high marginal costs will only operate during hours when demand is strong, and the going price exceeds their marginal costs. They may cease production entirely during some months of the year when demand is weak, or at night, when prices fall below their marginal cost.

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Q CAN YOU ELABORATE ON THE IMPLICATIONS OF JOINT COST RECOVERY PATTERNS FOR THE ONE OF THE KEY ISSUES IN THIS PROCEEDING: WHETHER QF RATES SHOULD INCLUDE PAYMENT FOR THE VALUE OF CAPACITY THEY PROVIDE?

A. Yes. The Company argues against making any payment to solar generators for the capacity benefits they provide – including electricity that is delivered to the grid on hot summer afternoons, when it is highly valued by users, and their capacity is very beneficial in helping to meet the need for electricity. Their reasoning is as follows:

> Since SCE&G's Reserve Margin Study shows that SCE&G needs as much capacity in the winter as it does in the summer, a resource has to provide capacity in the winter as well as the summer in order to avoid the need for capacity and thereby have capacity value. Because solar does not provide capacity during the winter period, the Company is unable to avoid any of its projected future capacity needs and, therefore, the avoided capacity cost of solar for these winter months is zero.[48]

Before discussing how this relates to joint cost recovery, I would first point out that this fundamental premise is wrong. SCE&G does not have an equal need for capacity in the winter and in the summer. This can easily be confirmed by studying a few graphs.

[48] *Id.*, Page 16.

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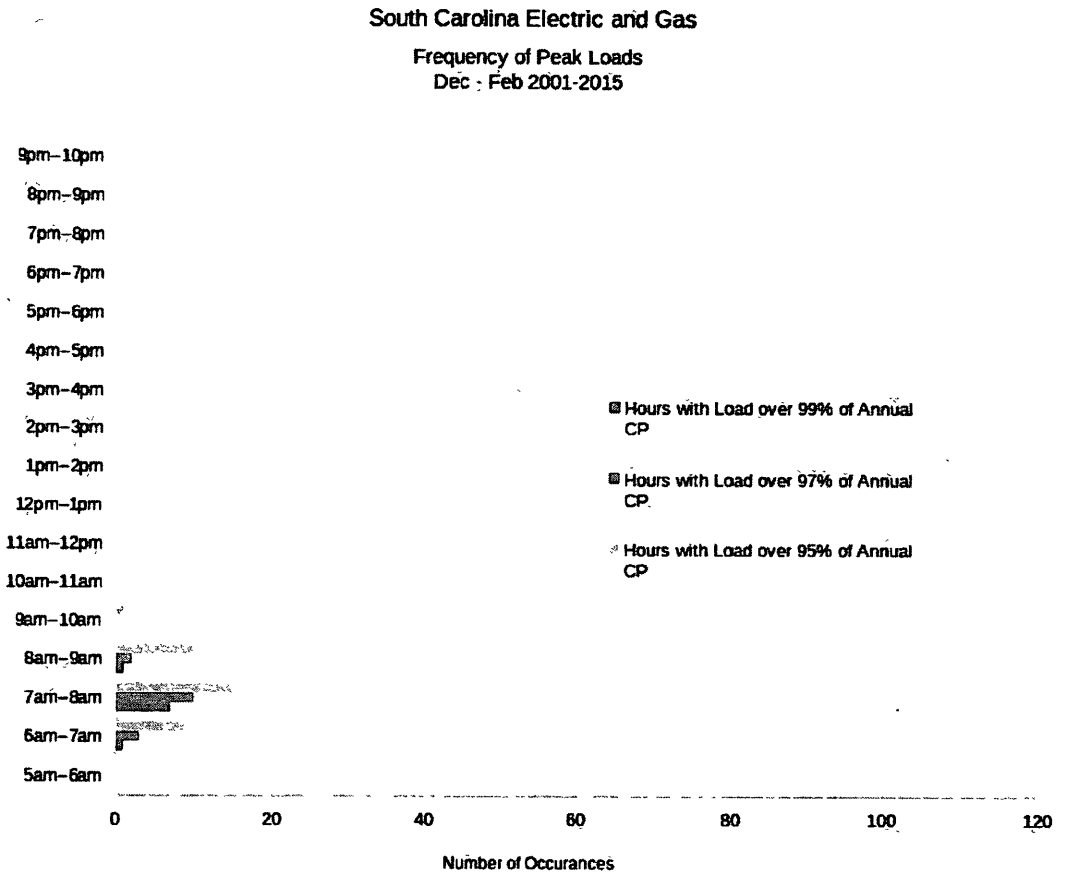
This first graph shows the number of hours when peak levels of usage occur during winter months.



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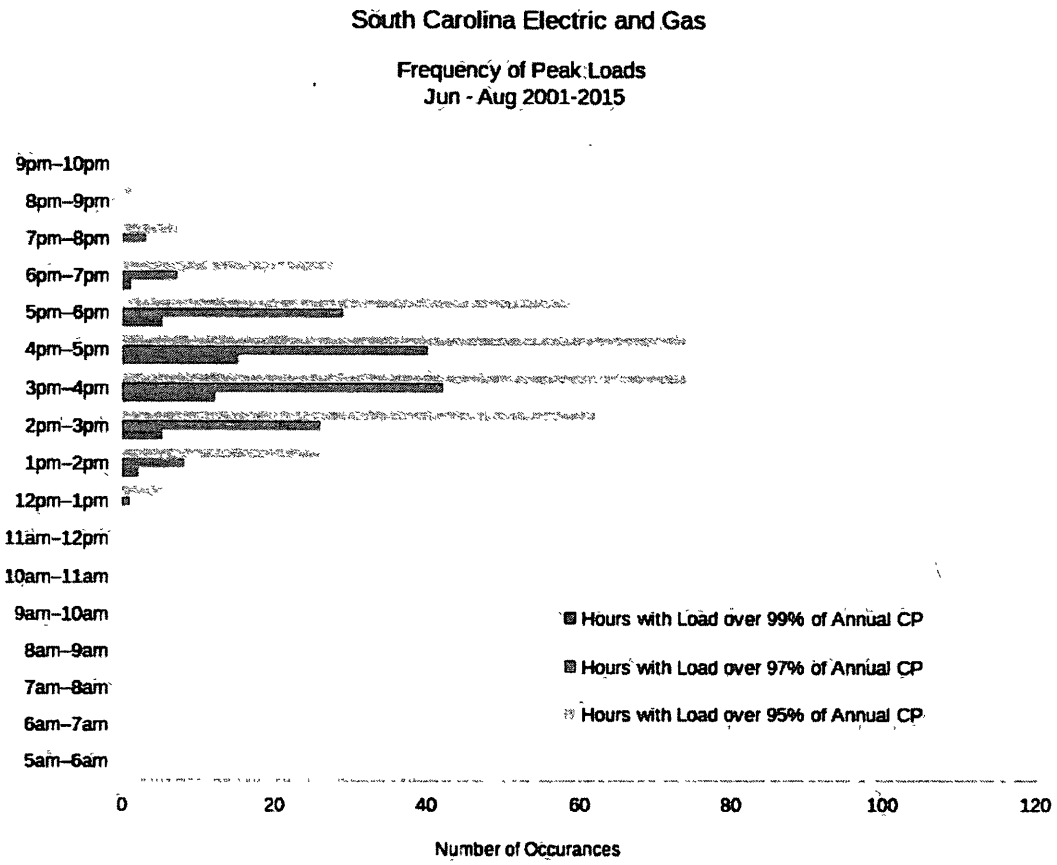
This second graph shows the analogous data for summer months.



Comparing these graphs, it is clear that peak levels of energy usage occur much more frequently in the summer months than in the winter months. The same conclusion can be reached by focusing on the most extreme peaks. This third graph shows extreme winter peaks:

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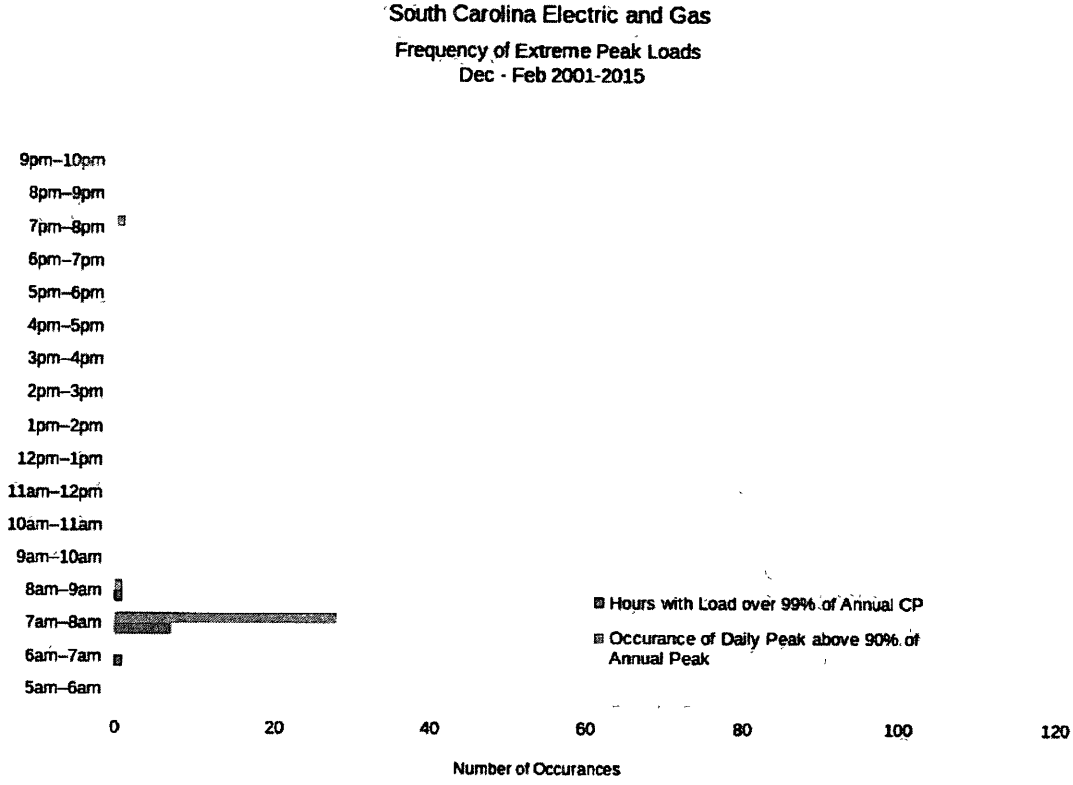

However, the fourth graph (on the following page) shows a much greater intensity and frequency of extreme peaks during the summer.

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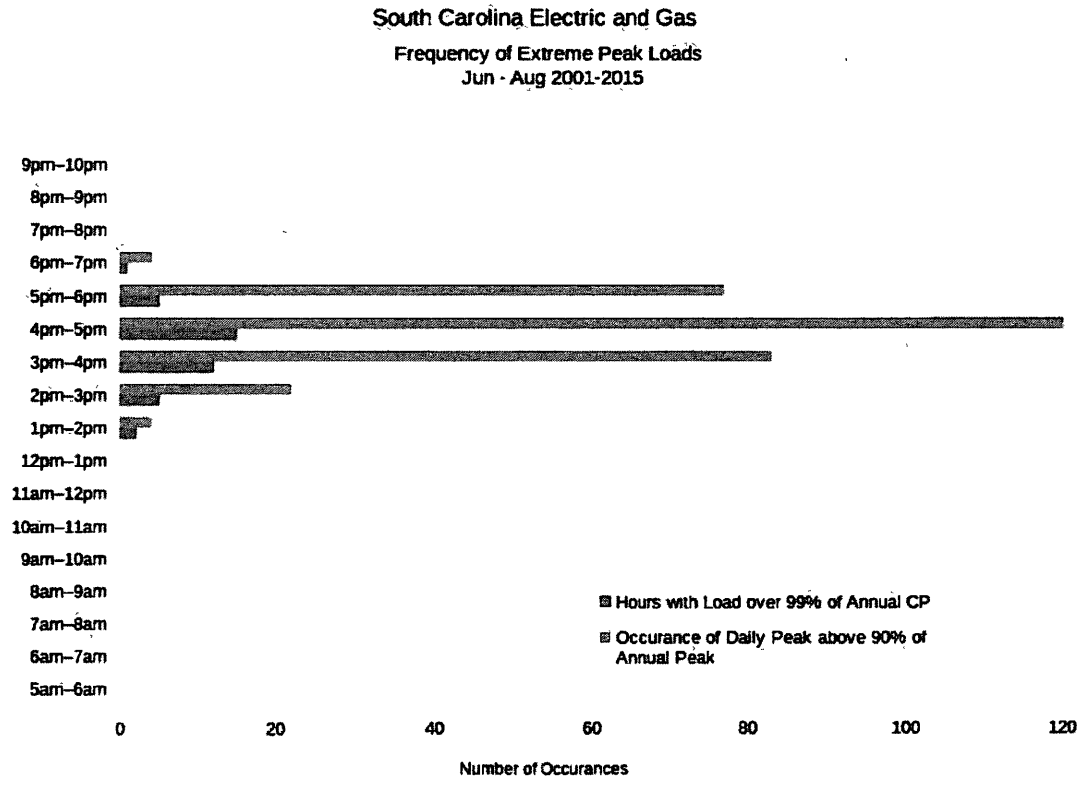
The Company is primarily a summer-peaking utility, the demand for electricity is generally stronger in the summer than in the winter, and both common sense and economic theory tell us that capacity costs should mostly be recovered from customers who are using electricity during high demand periods in the summer – not from users late at night, or during mild spring and fall days. The principles of joint cost recovery tell us not to take this reasoning too far, however. It would not be logical, fair, or appropriate to demand that the recovery of fixed capacity costs be 100% concentrated during the most extreme peak hours on summer afternoons, as shown on this fourth graph:



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Demand is very strong during these hours, and the value of energy generating capacity is very high during these particular hours, most of which are times when solar output is very high. Nevertheless, it is important to recognize that users benefit from generating capacity that is available during many other, lower usage, hours as well. The logic of joint cost recovery tells us that a reasonable share of the annual fixed costs of capacity should also be recovered during many other hours of the year – including the early morning hours of December through February, when extreme peaks also sometimes occur.

Q. SHOULD SOLAR AND NON-SOLAR GENERATORS BE PAID DIFFERENT PRICES?

A. No. In competitive markets, users pay for what they value. This is fair to the users and fair to the producers. No one penalizes a firm for using the "wrong" technology – except to the extent their technology decision results in them producing a product that is less valuable than if they made a different choice. The engineering characteristics of individual firms or technologies are irrelevant except to the extent they impact the way they choose to operate, or the value of energy they produce, which can vary depending on the hours when it is produced. Some types of generators (like nuclear) can operate 24 hours a day, but a lot of their energy is produced late at night, when demand for electricity is low. Other generators (like solar) can only operate during the daytime hours, but their production occurs when demand is strong. Both types of generators

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should logically be paid for the value of what they provide, when they provide it.

Q. IF A SOLAR GENERATOR CAN'T PROVIDE ENERGY DURING THE EARLY MORNING HOURS OF THE WINTER, DOES THIS JUSTIFY PAYING NOTHING FOR THEIR CAPACITY DURING THE REST OF THE YEAR?

A. No. Under joint cost recovery principles, there is no logical reason to require a supplier to provide service during winter mornings in order to receive payment for the reliability and capacity benefits they provide during summer afternoons.

Each generator should be compensated for the value of what it brings to the market. Generators that operate during both the summer and winter peaks quite properly should receive higher payments than those that only operate during one season or the other, since because they provide benefits during both seasons. But, it is not logical, or reasonable, or consistent with economic theory to refuse to pay a generator for a valuable service they are providing during the summer merely because they aren't also providing a similar service during the winter.

Q. CAN YOU COMMENT FURTHER ON THE NEED TO MEET EARLY MORNING PEAKS IN THE WINTER?

A. Yes. The need for generating capacity during the early morning hours in the winter is a very small part of a much bigger picture. Capacity needs exist throughout the year, and

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those needs can and should be met on a pooled basis, using an entire portfolio of resources. This is analogous to the way securities become more valuable when they are combined with other types of securities, in an overall portfolio. A growth stock may not provide any immediate income, but that doesn't mean it doesn't belong in the portfolio. No single security meets every need, yet each one can bring a different form of value to the portfolio. Similarly, generators should be evaluated in terms of the contribution they provide to the overall portfolio of generating resources. In this regard, this passage in the Company's testimony is revealing:

> Since SCE&G's need for capacity spans the entire year, it is necessary to spread avoided capacity costs throughout the year to reflect the Company's reliability risk as explained in the Reserve Margin Study.[49]

Some generators, with high marginal costs, may be operated during few hours of the year, yet they still bring value to the overall portfolio. It is reasonable for retail customers to pay the fixed costs of these rarely used generators, because they provide a backup source of power, and enhance overall reliability. Similarly, it is self-evident that generators that operate during hundreds or thousands of daytime hours are contributing very substantial value to the overall generating resource portfolio, notwithstanding the fact they do not operate at night, or during the early morning hours.

[49] *Id.*, Page 23.

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Q. ARE THERE INEXPENSIVE WAYS OF MEETING EARLY MORNING PEAKS IN THE WINTER?

A. Yes. While the need is real, it is actually a fairly easy problem to solve, because the peaks are of such short duration, and they occur so infrequently, (as can be seen in winter graphs above). The cost of meeting this need can be held far below the full annual cost of building and operating a generating unit. One potential solution is hinted at in this passage from the Company's Reserve Margin Study:

> ...very cold weather can make SCE&G's winter peak spike for an hour or two. A peak clipping resource available for a few hours may be better suited to address this risk than a generating unit.[50]

For example, large industrial customers might agree to an interruptible rate, which will provide them with a financial incentive to risk being interrupted a few hours per year, but only on cold winter mornings. This type of narrowly targeted "demand management" resource would likely be a very low cost option, since the frequency of interruption would be low, and there would be plenty of warning before any interruption – the risk only occurs during a handful of early morning hours during extreme cold snaps.

This is not the only option, however. Peaking units that are primarily in the portfolio for reliability purposes could also be operated during this small number of hours. Similarly, the need could be met by purchasing blocks of firm energy and capacity on the wholesale

[50] SCE&G 2017 Reserve Margin Study, Page 2.

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market, where the purchases are narrowly targeted to winter mornings. This option is likely to be very cost effective, since SCE&G is located in close proximity to the PJM power market. This is an extremely large, very liquid wholesale power market, which is primarily summer-peaking. Peak generators that obtain most of their revenues and profits from the summer months are in a good position to sell firm capacity during early winter mornings, without detracting from their main revenue stream.

Finally it is worth noting that the Company's Fairfield Pumped Storage unit can also fulfill this need. The reservoir can be filled overnight, and the water used to generate electricity during the early morning hours, when people are waking up and turning up their thermostats. This brief surge in demand is relatively sudden and relatively brief. That makes it an ideal match to the capabilities of the pumped storage unit, which offers a large amount of peak capacity, provided it is only operated for a short period of time. After a few hours, all of the water will run out.

Q. WHAT CONCLUSIONS SHOULD BE DRAWN FROM THIS DISCUSSION?

A. The Company's arguments for paying solar generators less than non-solar generators should be rejected. All QF's should be paid the full amount of energy and capacity costs they help avoid. Differences in payments to different generators should be based upon the differences in the hours when they operate, paying less for hours when demand is weak and more during hours when demand is high.

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Consistent with this reasoning, the Company's arguments for not paying capacity rates should also be rejected. All QF generators provide valuable capacity benefits when they operate during daytime hours. Those benefits are especially strong during hot summer afternoons, when the demand for energy is strong, which also happens to be a time when solar output is high. To refuse to make any capacity payments or to recognize any of the capacity costs that are avoided when QF generators operate during these hours is highly discriminatory and fundamentally wrong.

The mere fact that particular generators do not operate during a small number of unusually cold, early-morning winter hours is not a valid basis for refusing to pay QF's for the capacity benefits they provide throughout the rest of the year.

Avoided Capacity Costs

Q. HAVE YOU DEVELOPED ESTIMATES OF THE COMPANY'S AVOIDED CAPACITY COSTS?

A. Yes. I developed some benchmark avoided capacity cost estimates using the Proxy Unit method. The first estimate is based on a hypothetical nuclear plant, similar to the V.C. Summer project. The second estimate is based on a hypothetical Combined Cycle plant. The third estimate is based on a hypothetical Combustion Turbine.

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Q. BEFORE DISCUSSING YOUR COST ESTIMATES IN DETAIL, CAN YOU BRIEFLY SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S AVOIDED CAPACITY COSTS?

A. Yes. These calculations show that SCE&G's current rates are already well below the long run fixed costs of building and operating any of these three types of generating units over their economic life. It would not be reasonable to make any further reductions to these rates. Rather than reducing the QF capacity rate to zero, it would more be appropriate to increase the rate at least modestly, to be more consistent with the long run incremental cost of new capacity, while paying the capacity rate to QF's only during hours when their energy is making a valuable contribution toward meeting the Company's peak loads. This would better encourage QF development within SCE&G's service area, which would be consistent with the intent of PURPA and FERC's rules, would help lower retail rates over the long run, and help advance the public interest.

Q. CAN YOU BRIEFLY EXPLAIN HOW YOU ESTIMATED THE COST OF CONSTRUCTION FOR A NEW NUCLEAR GENERATING UNIT?

A. In my avoided cost analysis I assumed an installed cost of $5,350 per kW for a newly constructed nuclear unit. I developed this number by looking at publicly available information concerning construction costs, including cost estimates for the V.C. Summer

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nuclear plants prior to the time when SCE&G cancelled them.[51] I started with the $7.6 billion cost estimate for the V.C. Summer units, which was provided in the Company's June 2016 PURPA filing. However, I also considered the most recent available cost estimate published by the Energy Information Administration ("EIA") for new nuclear construction, which I adjusted to 2017 dollars using an annual inflation rate of 2.0% and to reflect local cost conditions using their state-specific cost adjustment factor.

Nuclear	Cost per kW in (2017 Dollars)
Proxy Unit	$ 5,350
EIA – Advanced Nuclear [52]	$ 5,652
SCE&G – Summer June 2016 Estimate	$ 5,307

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBINED CYCLE UNIT?

A. I started with an installed cost per KW in 2017 dollars of $1,050. This is slightly higher than the $993 figure SCE&G used as an input in its avoided cost calculations. The $1,050

[51] The Company's June 30, 2016 avoided cost filing in compliance with Subpart C, Section 210 of PURPA indicates the Company's next planned generating unit is VC Summer #2, which is projected to add 625 MW of capacity in 2020, 22 MW of capacity in 2021, and 23 MW in 2022. VC Summer #3 is expected to add 648 MW of additional nuclear capacity in 2021 and another 22 MW of capacity in 2022, for a grand total of 1,340 MW.

[52] See Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 ("2016 EIA Report"), Page 7. These calculations apply EIA's 4.9% location adjustment factor for South Carolina (Page A-20) and adjust for inflation at 2% per year.

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figure is consistent with multiple publicly available data sources:

Combined Cycle	Cost per kW (2017 Dollars)
Proxy Unit	**$ 1,050**
EIA – Advanced CC[53]	$ 1,126
Duke – Dan River CC[54]	$ 1,007
Duke – Buck CC[55]	$ 1,060
Brattle – Dominion [56]	$ 1,041
SCE&G – Workpapers[57]	$ 993

53 See 2016 EIA Report, Page 7. We applied the EIA's -10.4% location adjustment factor for South Carolina (Page A-14) and adjusted for inflation.

54 Duke completed its Dan River Combined Cycle plant in 2012. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $912, which is equivalent to approximately $1,077 in 2017 dollars.

55 Duke completed its Buck Combined Cycle plant in 2011. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $941 per KW, which is equivalent to approximately $1,060 per KW in 2017 dollars.

56 See The Brattle Group and Sargent & Lundy, Cost of New Entry Estimates for *Combustion* Turbine and Combined Cycle Plants in PJM, May 2014 ("Brattle Report"), Page 43.

57 See for example CC2023_ICT2023_0CO_BG.xlsm, tab Base PLAN, cell B12.

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Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBUSTION TURBINE?

A. I used an installed cost of $650 per KW in 2017. This is slightly lower than the $697 figure SCE&G used as an input in its avoided cost calculations in this proceeding. It is also lower than the $734 estimate SCE&G provided in its June 30, 2014 PURPA avoided cost filing. My decision to use the $650 figure is primarily based upon the most recent cost information published by the Energy Information Administration. However, I also considered two cost estimates provided by SCE&G, and two other publicly available data sources:

Combustion Turbine	Cost per kW in 2017 Dollars
Proxy Unit	$ 650
EIA – Advanced CT [58]	$ 645
Brattle – Dominion [59]	$ 885
Pasteris SOM – EMACC [60]	$ 763
SCE&G – 2023 CT [61]	$ 734
SCE&G – Workpapers [62]	$ 697

58 See EIA Report, Page 7. We applied the EIA's 6.8% location cost adjustment factor for South Carolina (Page A-18) and adjusted for inflation.

59 Brattle's estimate of the overnight cost of constructing an Advanced Combustion Turbine in Dominion's service area was $931 per KW in 2018/19. (Brattle Report, Page 41.)

60 See Brattle CONE CT Revenue Requirements Review, July 25, 2014, Page 12.

61 SCE&G June 30, 2014 PURPA avoided cost filing.

62 See for example CC2023_ICT2023_0CO_BG.xlsm, tab Change PLAN, cell G12.

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Q. HOW DID YOU TRANSLATE THE INSTALLED COST INTO ANNUAL EQUIVALENTS?

A. First, I added an allowance for the cost of construction financing. I then developed an allowance for depreciation based on an economic life of 30 years for the combined cycle and combustion turbine units, and 70 years for the nuclear unit. These are reasonable input assumptions, which are more realistic, more conservative and more appropriate than the corresponding life estimates used in SCE&G's avoided cost analysis of 60 years for a combustion turbine, 75 years for other fossil-fueled plants, 150 years for hydro and 80 years for nuclear.[63]

I developed an estimate of income taxes using a composite state and federal tax rate of 24.95%, and I applied a weighted cost of capital of 7.18% (a pre-tax cost of capital of 8.75%), consistent with the following calculations:

Capital Source	Ratio	Cost Rate	Weighted Cost	Tax Factor	Pre-Tax Weighted Cost
Equity	50.00%	9.50%	4.75%	1.3324	6.33%
Debt	50.00%	4.85%	2.38%	1.0000	2.43%
Total	100.00%		7.18%		8.75%

63 See for example CC2023_ICT2023_0CO_BG.xlsm, tab FCR-SCEG, cells D21, F21, H21 and J21, respectively.

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These capital-related ownership costs were initially developed for each individual year, then levelized across the entire economic life of the plant. The latter step is similar to the way most home mortgages are structured to provide uniform, level payments, even though the cost of the mortgage (the interest) varies from year to year. The end result was a uniform levelized capital cost of $451.86 per kW per year for the nuclear plant, $106.14 per kW per year for the combined cycle plant and $65.70 per kW per year for the combustion turbine.

Q. DID YOU CONSIDER ANY OTHER FIXED ANNUAL COSTS?

A. Yes. Before converting these levelized amounts into per-kWh costs, it was necessary to add an allowance for fixed O&M and corporate overhead costs. I assumed annual Fixed Operating & Maintenance expenses would be $95.00 per kW for the Nuclear plant, $10.00 per kW for the Combined Cycle Plant and $7.00 per kW for the Advanced Combustion Turbine (in 2016 dollars). The assumptions are consistent with estimates developed by the Energy Information Administration and data from various utilities, which I have reviewed in the course of my consulting work. Applying an annual inflation factor of 2% and levelizing each figure results in an annual cost per kW in 2017 of $119.64, $12.59 and $8.82, respectively.

I also applied a 95% availability factor, to compensate for forced outages and times when the unit is unavailable for energy production due to scheduled maintenance (and refueling

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in the case of a nuclear unit). An allowance for corporate overhead costs was also needed; I provided a 5% allowance for this category of costs. All of these costs were developed on a year-by-year basis, then uniformly spread across the economic life of the plant. The resulting levelized costs totaled $647.96 per kW for the nuclear plant, $131.23 per kW for the combined cycle plant and $82.36 per kW for the combustion turbine.

Q. HOW DO THESE AVOIDED COST ESTIMATES COMPARE TO THE COMPANY'S CURRENT QF CAPACITY RATES?

A. The current rates are 1.965 cents per kWh during the critical peak hours in the summer and 0.675 cents per kWh during the critical peak hours in the winter. Both rates are significantly lower than the long run avoided capacity costs associated with building and operating new generating plants. The exact comparison is shown in the following table:

SCE&G Proposed QF Capacity Rates vs.
Benchmark Avoided Capacity Costs (price per kWh)

	Summer (Jun – Sep)		Other (Oct – May)	
	Proposed QF Rate	Avoided Cost	Proposed QF Rate	Avoided Cost
Critical-Peak	$ .01965	$ .2698	$ .00675	$ .0807

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Recommendations

Q. WHAT ARE YOUR RECOMMENDATIONS FOR RESOLVING THE QF ISSUES IN THIS PROCEEDING?

A. The Commission should reject all of the proposed QF tariff changes, including the following:

- Reducing the capacity rate on the PR-2 tariff to zero;
- Reducing energy rates despite circumstances where heat rates have increased, providing stronger opportunities for avoiding high energy costs.
- Removing time-related price signals, which discourage investments in storage.
- Eliminating standard offer rates for non-solar generators larger than 100 kW.
- Basing rates on a generic solar profile, thereby removing incentives to invest in locations or technology that have the potential for achieving a better profile.
- Basing rates on a sub-optimal "Base" expansion plan that does not minimize revenue requirements.

The Company has not identified (and I am not aware of) an urgent need to update or revise the existing rates, which can continue in effect until these issues are properly addressed. I recommend that the Commission establish a process to fully consider the issues discussed in this testimony, and to encourage the Company to work collaboratively with ORS and other interested parties in an effort to reach a consensus on as many of the

technical issues as possible. The goal should be to develop stronger, more precise hourly price signals, consistent with the earlier discussion in my testimony. This can be accomplished by modifying the inputs and assumptions used in the DRR analysis, to more accurately analyze and minimize the revenue requirements under each scenario.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, WHICH WAS PREFILED ON MARCH 23, 2018?

A. Yes.

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Appendix A

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients have employed your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory commissions,

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public counsels, attorneys general, and local governments, among others. We have also worked for a wide variety of different private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission

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Virginia State Corporation Commission

Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

National Association of State Utility Consumer Advocates

New Hampshire Office of Consumer Advocate

New York State Department of State – Utility Intervention Unit

Ohio Consumer Counsel

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Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

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City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

Canada—Department of Communications

Hillsborough County Property Appraiser

Provincial Governments of Canada

Sarasota County Property Appraiser

State of Florida—Department of General Services

United States Department of Justice—Antitrust Division

Utah State Tax Commission

Regulated Firms

Alabama Power Company

Americall LDC, Inc.

BC Rail

CommuniGroup

Florida Association of Concerned Telephone Companies, Inc.

LDDS Communications, Inc.

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Louisiana/Mississippi Resellers Association
Madison County Telephone Company
Montana Power Company
Mountain View Telephone Company
Nevada Power Company
Network I, Inc.
North Carolina Long Distance Association
Northern Lights Public Utility
Otter Tail Power Company
Pan-Alberta Gas, Ltd.
Resort Village Utility, Inc.
South Carolina Long Distance Association
Stanton Telephone
Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

Other Private Organizations

AARP
Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Clark Canyon, LLC
Clearwater Paper Company
Coalition of Boise Water Customers

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Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
North Carolina Sustainable Energy Association
Skokomish Indian Tribe
South Carolina Solar Business Alliance
Tamarack Energy Partnership
Twin Falls Canal Company
World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the

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position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. I have been actively involved in more than 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Initially I prepare reports for the internal use of the Florida Public Counsel, but in the subsequent years I've prepared reports for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 300 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and

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in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and approximately 60 electric utilities. I have also worked on consulting engagements involving more than 35 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the International Association of Assessing Officers (IAAO), the Michigan State University

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Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA) and North Carolina State University.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly*, February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly*, December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times*, February 13, 1982, p. 19.

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"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly*, November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making*, December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review*, Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change*, edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth

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Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

WITNESS: In my surrebuttal testimony, on pages two through seven, I respond to the portion of Dr. Lynch's rebuttal testimony where he disputes Mr. Brian Horii's characterization of, quote, "dramatic changes," end quote, to the company's approach to its QF rates. I agree that these changes are very significant and need further study.

The company should not be given carte blanche approval of these dramatic changes, especially since they have not been fully disclosed or explained, and neither ORS nor the other parties have been given an adequate opportunity to investigate and fully respond to these changes. It was simply not feasible for ORS and the other parties to identify, fully investigate, or analyze all of these dramatic changes, including changes to the expansion planning model and related changes to the generation expansion plan, within the time constraints of this proceeding.

On pages seven through ten of my surrebuttal, I show that Dr. Lynch was wrong to imply that my testimony in this proceeding merely restates suggestions and recommendations I made last year. However, I admit there is one recommendation which

is largely repeated from last year's testimony, where I urge the Commission to establish a process that encourages the company to work collaboratively with ORS and other interested parties to work through the technical details of the QF issues. I believe everyone would benefit from a more flexible and collaborative process which provides ample opportunity for discovery, information sharing, and discussion of the QF issues.

On pages 10 through 11 of my surrebuttal, I show there is no disagreement concerning the requirements of PURPA. The disagreements concern whether and how these requirements are being fulfilled. Dr. Lynch is correct in opining that QF rates should be set equal to the utility's actual avoided cost, but he's wrong to completely exclude capital-related costs, including property taxes, insurance, salaries, depreciation, interest, and return on equity, since these are also avoided by QF purchases.

On pages 12 through 14, I show that applying the same DRR expansion planning model used last year, updated to reflect the company's current circumstances, including cancellation of the nuclear units, would have shown that substantial

capacity costs are avoided when power is obtained from solar QFs. I also show that the changes to the company's expansion model in this proceeding are not appropriate or adequate. I concede that further analysis is needed, but I am confident that an appropriate, unbiased modeling effort will confirm that adding more solar enables the company to avoid costs that are not included in the proposed QF rates but should be.

On page 15 of my surrebuttal, I clarify my position concerning PROSYM and my disappointment that the company did not provide the hourly output from this model, since the additional detail would be helpful in clarifying and resolving some of the issues in this proceeding.

On pages 15 through 16, I explain some of the relevance of my avoided cost estimates, and particularly how they demonstrate the importance and significance of the avoided-capacity-cost issue.

On pages 17 through 18, I note that Dr. Lynch had admitted, quote, "future natural gas prices are uncertain," end quote, and he didn't dispute the fact that the company put great emphasis on avoiding these risks when defending continued

construction of its nuclear construction program. I also note he has not disputed the fact that the company is ignoring these same risks in this proceeding. Now, to be clear, I'm not proposing to increase QF rates to reflect the reduction in risk achieved by QF purchases. Rather, I am offering this line of reasoning as an additional factor to consider when deciding whether to exclude capital-related costs or to estimate avoided costs using a new expansion planning model that has not been adequately explained or investigated by ORS and the other parties.

On pages 18 through 25, I discuss whether or not avoided-cost-based prices can provide good competitive outcomes. I explain that, in competitive markets, winners and losers emerge over time, driving down costs and helping to achieve what is called the wisdom of crowds. I explain the relevance of this process in the context of PURPA, which envisions a hybrid market structure which encourages risk-taking by competitors, helps diversify our energy supply, and reduces exposure to fossil-fuel risks. I go on to discuss the important role of prices in the competitive process, using the specific example of the duck

curve. Now, the simplest solution – if you want to call it that – to the duck curve is to discourage or prevent QF investment in solar energy. While this may seem attractive, from the perspective of a system planner or a monopolist, it would not be economically efficient. The competitive solution is to encourage QF investment in solar and storage until avoided costs are driven so low that further QF investments aren't worthwhile. With granular prices that convey accurate cost information to all market participants, the quantity of electricity produced and the quantity consumed during each hour will adapt to changing cost conditions as they evolve over time. This process will encourage an efficient rate of adoption of new technologies, including storage, and it will avoid inefficient investment decisions.

With this competitive process, buyers and sellers interacting in the marketplace will function like an invisible hand, increasing efficiency, encouraging innovation, and improving economic well-being throughout society.

On pages 25 through 27, I explain how this competitive process can drive down costs and prices, even during hours when the sun isn't

shining. As solar energy becomes more abundant, avoided costs will initially decline in the middle of the day, creating an opportunity to shift usage away from higher-cost hours and providing an incentive for QFs to invest in storage. This will have the effect of driving down costs and retail rates, even when the sun isn't shining. To fully accomplish this, the actual pattern of avoided costs cannot be submerged within a year-round, all-hours QF rate, as the company has proposed.

On pages 27 through 28, I explain why it is appropriate to include a markup above short-run variable costs, or running costs, and to provide compensation for the capital-related costs that need to be incurred in order to have the ability to generate electricity. While these capital-related costs are not part of the PROSYM output, they can and will be avoided as more solar energy is provided by QFs.

On pages 29 through 31, I rebut Dr. Lynch's testimony concerning summer and winter peaks. First, I note that the winter peaks don't require new generating units since they are relatively infrequent and brief. The most efficient way to meet this need is to pursue demand-side options

like the Standby Generator Program, the Interruptible Load Program, and a winter-peak clipping program. Second, I discuss language from the company's IRPs which explains why it is primarily a summer-peaking utility – underlying facts and logic that continue to be valid and applicable. Third, I show that Dr. Lynch is wrong when he claims that adding solar capacity only has an impact on capacity in the summer. While solar capacity offers its greatest benefits and avoids the most cost during the summer, it also offers winter – excuse me – it also offers benefits and avoids costs during the fall and spring and, to a small degree, during the winter.

On pages 31 through 35, I rebut Dr. Lynch's attempt to defend paying different rates for solar and non-solar QFs. I show that the QFs have different operating characteristics, yet they can all be appropriately compensated using a single technology-agnostic tariff reflecting hourly and seasonal cost patterns. I go on to explain why this approach is better than attempting to tailor different rates to match the characteristics of each technology or requiring QFs to negotiate rates. Forcing QFs to negotiate rates would create

regulatory uncertainty and discourage investment in South Carolina. Avoiding regulatory uncertainty and barriers to entry is particularly important in the context of emerging technologies like solar-plus-storage.

On pages 36 through 40, I discuss the rapidly growing importance of solar-plus-storage and I show that none of the company's proposed changes in this proceeding align as well with solar-plus-storage as the current QF tariff. The proposed all-hours rate for solar is obviously not compatible with storage, since a QF would receive less revenue from a solar project that uses storage than from one that doesn't include any investment in storage. The negotiated-rate option is not a viable alternative, either, because of many problems, including a problem with circularity. There are many possible storage configurations, each with different characteristics. Without a reasonable degree of regulatory certainty with respect to rates, it becomes impossible to meaningfully evaluate investments that allow power to be generated in one time period and sent to the grid in another. Telling a QF that rates are subject to negotiation is no better than saying the potential benefit from

investing in storage investments is completely unknown. Adding that sort of regulatory uncertainty on top of all the other risks and uncertainties associated with new technologies will greatly discourage or preclude QF investments in storage – a result that is not in the best interest of the company's retail customers or the State of South Carolina, as a whole.

That completes my summary, and I appreciate your indulgence in listening for so long.

[PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED SURREBUTTAL TESTIMONY {W/CORR'N} OF BEN JOHNSON, Ph.D., FOLLOWS AT PGS 799-838]

The correction noted herein reflects the testimony given during the hearing in this matter.

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SURREBUTTAL TESTIMONY OF

Dr. Ben Johnson

ON BEHALF OF THE

SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

Before the

PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2018-2-E

Introduction

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida.

Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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Q. WHAT IS THE PURPOSE AND SCOPE OF THIS TESTIMONY?

A. I am responding to the rebuttal testimony of Joseph M. Lynch, on behalf of South Carolina Electric & Gas Company ("SCE&G" or the "Company") concerning the proposed rates to be paid to Qualified Facilities ("QF"). I focus almost exclusively on pages 34-46 of his testimony – his response to my direct testimony. My failure to comment on other parts of Mr. Lynch's testimony should not be construed as agreement with the statements he makes, or the conclusions he reaches in those parts of his testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I've largely followed the same sequence used by Dr. Lynch.

Q. IS IT FAIR TO CHARACTERIZE CHANGES PROPOSED BY SCE&G IN THIS PROCEEDING AS "DRAMATIC"?

A. Yes. Dr. Lynch disagrees with the conclusion reached by Brian Horii, testifying on behalf of the Office of Regulatory Staff ("ORS"), that SCE&G is implementing a "dramatic change in approach" in this proceeding.[1] Yet, his only basis for disagreeing is his vague claim that the Company is still "using the same difference in revenue requirements ("DRR") methodology previously approved by the Commission." In reality, the DRR

1 Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 2.

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method is simply one of three broadly accepted methods for estimating avoided costs. Numerous methodological details determine how the DRR method is implemented. The Company has undertaken a "dramatic change in approach" in how it is implementing the DRR method. These changes have not been fully identified, nor has there been an opportunity to fully investigate and analyze them.

The Company should not be given a *carte blanche* to make changes to its methodology, merely because it claims the revised methodology stays within the broad boundaries of the DRR method. To the contrary, all changes to its methodology, including changes to its expansion planning model, should be fully disclosed and explained, and the parties should be given an adequate opportunity to investigate and respond to those changes – and to propose alternative changes of their own.

Significantly, Dr. Lynch does not claim the version of the DRR method the Company used in this case is identical to the version approved in past proceedings. In fact, a close comparison of the workpapers provided in this proceeding (particularly the ones related to its avoided capacity costs) with the analogous workpapers provided in past proceedings suggests there are many significant differences. While there hasn't been an opportunity to fully examine those differences, they clearly are of sufficient magnitude and significance to justify the description that a "dramatic change in approach" has been proposed by the Company in this proceeding. These changes go far beyond merely updating inputs within the context of the previously approved methodology – something

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that could have been accomplished by simply updating some of the cells contained in the workpapers the Company used in preparing last year's filing.

It was simply not feasible for the parties to fully investigate and analyze these dramatic changes to the Company's approach – including changes to the expansion planning model and related changes to the generation expansion plan – within the time constraints applicable to this proceeding. The Company had many months to develop its proposals, and it gained additional time when it obtained permission to postpone its QF rate filing from December 2017 until February 2018. In contrast, the non-Company parties were provided less than 45 days to examine the Company's QF rate proposals and supporting workpapers, and to prepare their responsive testimony.

Last year, I noted that the fuel proceeding is not the "ideal forum" for fully exploring and resolving some of the policy concerns and methodological issues affecting QF rates. That observation remains true, and the need for more time to work through the details of the QF-related issues is even more apparent given the "dramatic changes" in approach being proposed by the Company.

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Q. THIS PROCEEDING CONTAINS HUNDREDS OF PAGES OF TESTIMONY. ARE YOU SUGGESTING THERE WASN'T AN ADEQUATE OPPORTUNITY TO INVESTIGATE AND DISCUSS THE QF ISSUES?

A. Yes. I realize this is counter-intuitive, given the sheer volume of material filed by the parties. In reality, some QF issues have been discussed extensively, while others have barely been touched.

In a typical rate case, or in complex corporate litigation involving highly technical, complex issues like the ones being dealt with here, the schedule would provide an opportunity for the parties to engage in multiple rounds of discovery, including follow-up questions or depositions. This would ensure that all parties have an opportunity to fully understand the workpapers, supporting studies and other evidence being relied upon by the other parties. This level of understanding and disclosure was precluded by the circumstances of this proceeding.

One indication of the problem is the fact that there is remarkably little overlap in the details discussed in the simultaneous testimony filings by the non-Company parties on March 23. For instance, a large part of Mr. Horii's testimony is focused on the Company's 2017 Reserve Margin Study, which I decided not to discuss, because I didn't have time to examine the supporting data, nor an opportunity to ask questions about it.

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Similarly, neither Mr. Horii nor I had a chance to fully examine changes the Company made to its expansion planning model, or to analyze how those changes affected the PROSYM inputs and outputs. I briefly touched upon a few aspects of these changes in my testimony, but due to time constraints I was not able to fully investigate them. The lack of more discussion of the impact of these changes on the avoided energy cost estimates does not imply a lack of relevance or significance. Rather, it demonstrates one of the problems with the Company's "dramatic change in approach" in this proceeding.

Q. CAN YOU EXPLAIN HOW CHANGES TO THE COMPANY'S EXPANSION PLANNING MODEL AFFECT THE AVOIDED ENERGY COSTS?

A. Yes. The "Base" and "Change" expansion plans are fundamental to the DRR method. The generating units that are assumed to exist, and the extent to which demand side management will be used to accommodate peak demands, the extent to which firm capacity will be purchased, and the extent to which new generating units will be acquired, affects the inputs used in running PROSYM. In turn, these inputs help determine the hourly PROSYM outputs, which determine the proposed avoided energy rates.

Yet, changes to the expansion planning model are not even mentioned by Mr. Horii. I confirmed this by searching for the word "expansion" and I only found this word used in the context of his past experience and qualifications. This is not a criticism of Mr. Horii, nor a suggestion he might have failed to recognize the importance of this issue. Rather, I

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am using this example to demonstrate that it was not possible for the non-Company parties to fully investigate and respond to the "dramatic changes" included in the Company's filing.

Accordingly, I continue to believe it would be better to explore these issues in a procedural context that provides ample opportunity for discovery, and which encourages the parties to work collaboratively, in an effort to reach a consensus on as many of the technical issues as possible.

Q. DR. LYNCH IMPLIES YOUR TESTIMONY MERELY RESTATES SUGGESTIONS AND RECOMMENDATIONS FROM YOUR TESTIMONY IN THE COMPANY'S 2017 PROCEEDING. IS THIS TRUE?

A. No. Of course, my testimony is largely consistent with my testimony last year, and I have repeated some of my criticisms and suggestions. However, my testimony in this proceeding has emphasized changes to the Company's circumstances since last year – including cancellation of the nuclear construction program and the associated increase in fossil fuel-related risks – and proposed changes to the Company's tariffs. More specifically, I recommended against these proposed changes:

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- Reducing the capacity rate on the PR-2 tariff to zero;
- Reducing energy rates despite circumstances where heat rates have increased.
- Removing time-related price signals.
- Eliminating standard offer rates for non-solar generators larger than 100 kW.
- Basing rates on a generic solar profile.
- Basing rates on a sub-optimal "Base" expansion plan that does not minimize revenue requirements.

With the possible exception of the last item, these are all new recommendations, related to the dramatic changes proposed by the Company in this case. As to the final item, last year I expressed some concerns regarding the importance of correctly optimizing the "Base" expansion plan in the DRR method. However, this problem is much more serious in this proceeding, because the Company has made extensive changes to its expansion plan in an apparent reaction to cancellation of the nuclear units. This strongly suggests the need to revisit this issue.

Admittedly, some of my recommendations are similar to last year, like this one:

> I recommend the Commission require the Company to collaboratively work with ORS and other interested parties to develop higher, more accurate QF rates. This can be accomplished by modifying the inputs and assumptions used in the DRR analysis, to more accurately analyze and minimize the revenue requirements under each scenario.[2]

While this recommendation was not implemented, I think the subsequent experience confirms it had merit. I believe everyone would have benefited from a more flexible, collaborative effort to discuss and resolve QF rate issues without narrow time constraints.

2 Direct Testimony of Ben Johnson, Docket No. 2017-2-E, Page 93.

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Among other benefits, a more open and collaborative process, with ample opportunity for discovery, information sharing and discussion, would have provided the solar industry with a better opportunity to understand the Company's concerns about the impact of rapid growth in solar generation, and it would have provided the Company with a better opportunity to understand the solar industry's suggestions for how accommodating this growth can help reduce the revenue requirement and reduce risks for retail rate payers.

Perhaps this lack of two-way communication is one reason why the Company developed its DRR calculations using expansion plans that effectively ignore solar capacity that is already in the Company's interconnection Queue, as well as capacity that will soon be added to the Queue. Accordingly, I offered a similar recommendation near the end of my direct testimony in this year's proceeding:

> I recommend that the Commission establish a process to fully consider the issues discussed in this testimony, and to encourage the Company to work collaboratively with ORS and other interested parties in an effort to reach a consensus on as many of the technical issues as possible. The goal should be to develop stronger, more precise hourly price signals, consistent with the earlier discussion in my testimony. This can be accomplished by modifying the inputs and assumptions used in the DRR analysis, to more accurately analyze and minimize the revenue requirements under each scenario.[3]

This year's recommendation mentions the need for stronger, more precise hourly price signals, because this issue is growing in importance, and it would benefit from being discussed outside the time constraints of a fuel proceeding. The impact of increased solar

3 Direct Testimony of Ben Johnson, Docket No. 2018-2-E, Pages 128-129.

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generation on avoided cost patterns can be anticipated now, using the same computer modeling tools traditionally associated with the DRR approach. It is simply a matter of asking the right questions, and studying the detailed, hourly output from those tools, rather than ignoring that detail and rolling the numbers up into a few broad averages. This would improve QF price signals and help avoid costly mistakes in the generation expansion plan which might otherwise burden retail customers.

Q. DR LYNCH ARGUES THAT PURPA DOESN'T REQUIRE "ANY ELECTRIC UTILITY TO PAY MORE THAN THE AVOIDED COSTS FOR PURCHASES". DO YOU AGREE?

A. Yes. This is consistent with the portion of PURPA I quoted on page 12 of my direct testimony, which requires that QF rates not exceed ""the incremental cost to the electric utility of alternative electric energy."[4] This statutory requirement is consistent with the interpretation recently offered by the North Carolina Utilities Commission that "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."[5]

None of the witnesses in this proceeding are suggesting that QF rates should be set at a level that exceeds the incremental cost of obtaining electrical energy from alternative

4 16 U.S.C. § 824a-3(a).

5 North Carolina Utilities Commission, December 31, 2014 Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, Page 21.

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sources. All of the disputes involve how to correctly estimate those costs. In particular, Dr. Lynch proposes to exclude any consideration of the capital-related costs of alternative energy sources. Regardless of the underlying reasoning or logic, this is clearly an extreme position – one that is not consistent with the requirements of PURPA. The Company incurs substantial capital-related costs in order to maintain the ability to use alternative energy sources. Obvious examples include property taxes, insurance, and the salaries of the people who maintain and operate the Company's generating units.

Since these are fixed costs that do not vary directly with how and when each generating unit is operated, they are not included in the PROSYM output Mr. Lynch used to develop his proposed energy rates. Since PROSYM focuses only on running costs, and the proposed QF energy rates exclude costs that are not in the PROSYM output, it is clear that none of these capital-related avoided costs are reflected in the proposed QF rates. Yet, under PURPA, capital-related fixed costs are part of the "avoided" or "incremental" cost of providing electrical energy.[6]

In sum, there is no disagreement concerning the requirements of PURPA. The disagreements concern whether, and how, these requirements are being fulfilled. Dr. Lynch is correct is opining that "QF rates should be set equal to the utility's actual

6 Avoided cost "includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities." See https://www.ferc.gov/industries/electric/gen-info/qual-fac/orders/order-69-and-erratum.pdf

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avoided cost" but he is wrong in excluding capital-related costs, including property taxes, insurance, salaries, depreciation, interest and return on equity.

Q. DO YOU AGREE WITH THE CLAIMS DR. LYNCH MAKES AT PAGE 36 CONCERNING "INCREMENTAL SOLAR"?

A. No. He argues that "incremental solar beyond the 865 MWs of solar capacity already under contract does not alter [SCE&G's] resource plan and, therefore, the difference in revenue requirements is zero."[7] This bold assertion is not supported by any of the workpapers or other documentation provided by the Company. We were provided dozens of files related to the development of its "Base" expansion plan, yet none of these files consider the impact of adding additional solar capacity. Not only has the Company not adequately modeled solar growth, some of the changes it made to its "Base" expansion plan are sub-optimal given the growth of solar. For instance, the Company has not included additional DSM or power purchases that are specifically targeted at unusually cold winter mornings. Because the "Base" expansion plan excludes or ignores these types of opportunities (as with the modeling that was done in this proceeding), the avoided costs that are calculated using the DRR method will be underestimated.

In general, solar provides energy during daytime hours throughout the year. This makes it feasible to avoid the running costs and capacity-related costs of alternative energy

7 Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 36.

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sources. To accurately model the full extent to which costs can be avoided, it is necessary to refine the resource mix to ensure there is enough flexibility to take full advantage of the benefits of solar, while also recognizing its limitations – solar energy isn't produced before the sun rises or after it sets.

The expansion planning model used by the Company in last year's proceeding estimated the reduction in revenue requirements associated with adding more solar in a simplified way, by assuming the Company would avoid incremental purchased power costs. That opportunity for cost savings was somewhat constrained by the assumed addition of the nuclear units, but (appropriately) the model assumed larger power purchases if the nuclear units were postponed or canceled. If the Company had simply used that same approach to its current circumstances (reflecting cancellation of the nuclear units) it would have shown additional solar reducing the need for purchased power, thereby avoiding a significant amount of capital-related costs.

Admittedly, last year's modeling effort could be improved upon. In particular, it would be better to refine the model by taking into account the opportunity to purchase power on a targeted basis that focuses on specific hours (like early morning hours around sunrise, and early evening hours around sunset) when demand tends to be strong enough to justify some power purchases, but solar (in the absence of storage) cannot fully meet the need. Logically, this sort of targeted purchase should be less costly than purchasing power on an unrestricted "on demand" or "as needed" basis, since it leaves the seller free to sell

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firm energy to other buyers during other hours of the day.[8] Similarly, in the context of additional solar, the model could be further improved by including inexpensive Demand Side Management or other "peak clipping" resources that are narrowly targeted at unusually cold winter mornings.[9] This type of narrowly targeted resource is less costly than purchasing peaking capacity. Including it in the resource plan would further reduce the revenue requirement and will improve the accuracy of the avoided capacity cost calculations.

While further analysis is needed, I am confident that incremental solar beyond 865 MWs of solar capacity will significantly affect the optimal resource plan, and the resulting difference in revenue requirements will be substantially more than zero. Stated another way, an appropriate, unbiased modeling effort will confirm that adding more solar provides the Company with opportunities to reduce its revenue requirements, thereby avoiding costs that are not included in the PROSYM output, but should be reflected in the QF rates.

8 The potential cost savings from this type of purchase will become more significant if the daily peak shifts to the late afternoon or early evening.

9 SCE&G 2017 Reserve Margin Study, Page 2.

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Q. AT PAGE 37 DR. LYNCH STATES A DISAGREEMENT WITH YOUR TESTIMONY CONCERNING PROSYM. CAN YOU BRIEFLY RESPOND?

A. Yes. Dr. Lynch apparently misunderstood my testimony. I did not claim it was inappropriate to use PROSYM. Rather, I provided a balanced discussion of some of the advantages and disadvantages of this type of model. To the extent I criticized the Company's decisions concerning PROSYM, I was simply expressing my disappointment that the Company did not provide the Commission or interested parties with more of an opportunity to examine the PROSYM output. To fully understand and explore some of the issues discussed in my testimony – particularly the impact of additional solar and the need for stronger, more precise hourly price signals, it would be helpful to have detailed hourly output from all of its PROSYM runs available for analysis and discussion.

Q. AT PAGES 37-38 DR. LYNCH OFFERS SOME COMMENTS CONCERNING YOUR COST ESTIMATES. CAN YOU BRIEFLY RESPOND?

A. Yes. Dr. Lynch is apparently confused about the relevance of these cost estimates. I provided them not as an alternative to calculations developed using PROSYM or the DRR method, but rather as a way communicating more clearly the potential magnitude and significance of the issues discussed in my testimony. For example, Dr. Lynch acknowledged that, under PURPA, avoided capacity costs:

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> are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.[10]

Yet, he failed to provide any allowance for these costs in his proposed QF rates, and he did not develop any estimates of avoided capacity costs which could be used to rectify this omission. My cost estimates demonstrate this is a very serious omission, and they clarify that the omission can be disaggregated into two categories – the portion of the capital-related costs that relate to the ability to provide energy during peak hours (typically estimated based upon the cost of owning a Peaker) and the portion that relates to the ability to burn fuel more efficiently than a peaker (benefiting from the lower heat rate of an intermediate or base load generating unit). Both types of capital-related costs are required in order to have "the capability to deliver energy." The former category is primarily relevant to a small number of peak hours, while the latter category is potentially relevant to a wider range of hours across the year. Both types of avoided cost have been excluded from the Company's QF rates in their entirety (but should not have been).

In sum, my avoided cost estimates are relevant because they help explain and quantify this categorical distinction, and they quantify and communicate the potential significance of the failure to estimate these costs, or to include them in the proposed QF rates.

10 Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 4 (citing Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980)).

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Q. AT PAGES 38-39 DR. LYNCH OFFERS SOME COMMENTS CONCERNING YOUR TESTIMONY ABOUT FUEL-RELATED RISKS AND THE CANCELED NUCLEAR UNITS. CAN YOU BRIEFLY RESPOND?

A. Dr. Lynch has not offered any disagreement with any of the factual information I provided in this section of my testimony.[11] While he defends his natural gas price assumptions (which I did not criticize), he also admits "future natural gas prices are uncertain" which is the key point. Importantly, he does not dispute the fact that the Company put great emphasis on fuel risks when defending continued construction of its nuclear construction program, nor has he disputed the fact that the Company is now ignoring these same risks when developing its proposed QF rates.

It is worth noting that he did not dispute my conclusion that, when considering ratepayer "indifference," there is an important difference between the risks customers are exposed to when electricity is generated using fossil fuels, and the much lower risk exposure associated with the Company's hydro facility or purchases from a QF at a known price that is fixed in advance. As I explained in my direct testimony:

> All else being equal, a customer will prefer a guaranteed fixed price to a mere estimate of what they might end up paying. To leave a customer indifferent between a renewable QF energy source at a guaranteed fixed price, and a fossil fuel source it is necessary to add a risk premium to the former option before attempting to draw any meaningful conclusions about which technology is preferable from a customer perspective.[12]

11 Direct Testimony of Ben Johnson, Docket No. 2018-2-E, Pages 51-88.

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To be clear, I am not asking the Commission to increase the QF rate to reflect this difference in risk. Rather, I am offering this risk difference as an additional factor to be considered when the Commission is resolving other disputed issues in this proceeding – for example, whether to exclude capital-related costs, and whether to estimate avoided energy costs using the previously approved methodology and expansion planning model rather than the new model used by the Company in this proceeding.

Q. AT PAGE 41 DR. LYNCH DISAGREES WITH YOUR DISCUSSION ON PAGES 88-95 CONCERNING STRONGER, MORE PRECISE PRICE SIGNALS. CAN YOU BRIEFLY EXPLAIN THIS DISAGREEMENT?

A. Yes. He explains his disagreement as follows:

> PURPA requires SCE&G to purchase the power produced by any and all QFs that desire to sell power at the Company's avoided cost. SCE&G is prohibited by law from turning away less efficient QFs so the use of avoided costs is not a good vehicle to enhance competitive markets.[13]

His disagreement is primarily contained in the latter half of his second sentence – whether more precise avoided cost-based prices provide a good vehicle for improving competitive outcomes. I will explain in considerable depth why he is mistaken about this, because this particular dispute goes to the heart of some of the most misguided aspects of the Company's proposed changes to its QF tariffs: the proposal to segregate

12 Ibid, Page 56.

13 Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Page 41.

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solar production from other forms of energy production, the proposal to eliminate capacity payments, and the proposal to change from Time of Day pricing to a uniform "all hours" kWh rate.

To be clear, I agree the Company does not have the option to refuse power generated by competing firms. Nor, should the Company be allowed to keep competing firms out of the market by reducing the price below avoided cost. Federal law requires the Company to purchase QF power at prices that are determined by state regulators – not by the monopolist. QF rates are supposed to be based upon avoided cost, to ensure that over the long term retail customers pay no more than what they would have paid if all of their power had continued to be supplied by the utility.

Similarly, I agree that PURPA does not require someone to decide which competitors are less efficient, nor does it provide any mechanism to "turn away" these less efficient firms. Instead, the competitive process is supposed to determine which firms succeed and which ones fail, just as it does in other parts of our market-directed economy. Consider what happens in a competitive agricultural market. All farmers receive a similar price for their production, and all are free to produce as much as they want. Hence, success or failure largely depends on their decisions – which crops they plant, the timing of when they plant, how frequently they fertilize, what fertilizers they use, the extent to which they irrigate, how and when they harvest their crops, and so forth. Every firm makes slightly different decisions, and some decisions are better than others.

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In competitive markets, winners and losers emerge over time, with inefficient firms earning less than their cost of capital, and eventually going out of business. The most efficient firms expand and thrive, and other firms attempt to emulate their success – adopting their innovations and trying to match their decision-making prowess. This is fundamentally different from what happens in a monopoly market, where the monopolist is shielded from competition by legal or other barriers to entry, which enable it to potentially expand and thrive, regardless of how badly mistaken some of its decisions turn out to be, and regardless of how much those mistakes harm consumers and society as a whole.

PURPA envisions a hybrid market structure, where electrical distribution (and to a lesser extent transmission) continues to function as a monopoly, but competition is encouraged in power generation. Independent power producers are allowed to enter the market and produce as much electricity as they want – provided they use small generators and specific technologies, like hydro, solar, biomass, geothermal, and wind. This creates a more competitive environment, it helps diversify our energy supply, and it reduces exposure to the risks associated with fossil fuels.

While PURPA relies on competition to achieve many of its goals, it retains a crucially important role for monopoly regulation – determining the prices to be paid by the monopolist to its competitors. The pivotal question, then, is what is the point of regulating QF rates? I believe answering this question explains why avoided costs

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provide a good vehicle for encouraging entry into the power generation market, and achieving the intended goals of PURPA without adverse consequences to retail customers or society as a whole.

Q. WHAT ROLE DO PRICES PLAY IN COMPETITIVE MARKETS?

A. Their most fundamental function is to provide information to market participants. Prices help consumers decide how much they can afford to consume and they help them optimize their consumption decisions – how much to purchase of one item rather than another. Prices play a similar role for producers – helping guide their decisions concerning how much to produce of one item or another, how and where to invest their capital, and what inputs to use in the production process.

I believe – and I think most economists would agree with me – that the information embedded in prices is crucially important in explaining why well-functioning markets are so successful at achieving societal goals. In fact, history has repeatedly demonstrated that a well-functioning market can be more successful at accomplishing many societal goals than a system with greater centralized control, even when that system is attempting to directly advance those same goals. This has repeatedly been demonstrated when countries have arbitrarily constrained specific prices, in an attempt to make them more "affordable." The inevitable end result is that too little is produced, rationing becomes necessary, and people end up worse-off than if prices had continued to serve their

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informational function, encouraging more production of the items that are most desired by consumers. Similar problems occur throughout centrally planned economies – bureaucratic control over economic decision making inevitably breaks down, despite the best efforts of the decision makers, if price signals fail to adequately and accurately guide production and consumption decisions.

Experience has repeatedly shown that freely functioning markets with strong, accurate price signals help achieve societal goals, because of their vital role in helping to achieve the "wisdom of crowds." With effective competition, buyers and sellers interacting in the marketplace function like an "invisible hand," increasing efficiency, encouraging innovation, and improving economic wellbeing throughout society.

Q. CAN AVOIDED COST-BASED QF RATES PLAY A SIMILAR ROLE?

A. Yes. Utility regulation often works best when it emulates the most beneficial, successful attributes of competitive markets. I believe the Commission would be well-advised to consider the example of well-functioning prices in competitive markets, and in particular the crucially important role that accurate price signals provide to market participants.

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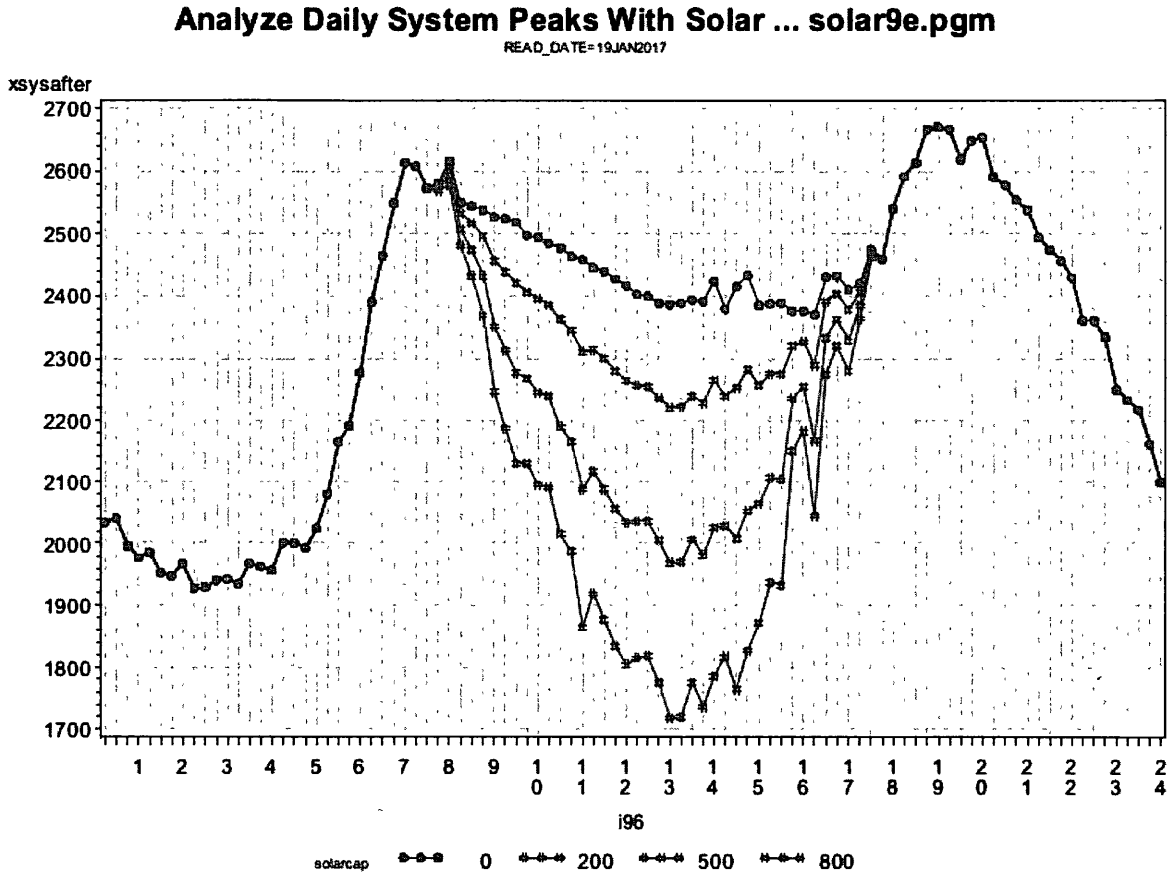
To demonstrate why this is true, consider the potential problems associated with a "Duck Curve" as illustrated in the graph below, from the Company's filing.[14]



The demand for electricity is illustrated by the top line, including the blue portion which shows the amount of electricity customers use during daytime hours, absent solar production. An initial peak occurs around 7 am, and a slightly higher peak occurs around 7 pm. The lowest level of demand occurs in the middle of the night around 3 am. A

14 Exhibit No.___(JML-3), Page 2 of 10.

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broad, shallow dip in demand occurs during the day, since this is January, there is no need for air conditioning, and the need for heat diminished as the day warms up.

The light red lines in the middle of the graph simulate what happens to the rest of the system as 200, 500 and 800 MWh of solar energy, respectively, are provided during the hour of maximum solar production. To be clear, these numbers do not represent the amount of installed solar capacity. To achieve this much solar energy on a typical winter day would probably require more installed capacity – perhaps as much as 1,800 MW, in the case of the lowest line.

As more solar energy is brought into the resource mix, potential "problems" emerge. Some of the output of the existing baseload units will be displaced by lower-cost solar energy. This will drive down (and be reflected in) the avoided cost calculations, causing those units to be operated below their optimal rate of output (typically near 100% of capacity). This isn't necessarily a problem, except from the perspective of the owner of those units, since it reduces the economic viability and usefulness of those legacy investments. Similarly, there may be problems with the "ramp rates" and other operating characteristics of some of the older baseload units, since they don't have a lot of operational flexibility – making those investments appear less attractive than when they were first made.

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In a monopoly-controlled market, the easiest way to avoid all of these "problems" is to simply not add much solar capacity. This "solution" avoids making the legacy investments appear less useful and obviates any need to take these investments out of the rate base after 30 or 35 years, rather than continuing to use them for 40 or 50 years. While this "solution" may appear attractive from the perspective of a system planner or a monopolist, it would not be economically efficient. In contrast, the competitive solution would continue to add solar energy until avoided costs are driven so low that further investments aren't worthwhile. In effect, granular prices convey accurate cost information to all market participants, so the quantity of electricity produced and the quantity consumed can adapt to actual costs as they evolve over time. This encourages an efficient rate of adoption of new technologies, including storage, and it avoids inefficient investment decisions.

Q. CAN STRONGER, MORE PRECISE RATES DRIVE DOWN AVOIDED COSTS DURING HOURS WHEN THE SUN ISN'T SHINING?

A. Yes. Consider again the example in the graph above. In the absence of solar production, the lowest cost time to produce power is in the middle of the night, when demand is low. However, at least on this particular day it costs more to produce power at 8 am or 7 pm than it does in the middle of the day. Furthermore, this hourly cost pattern will change as more solar energy is produced. The changing patterns will be reflected in the hourly

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avoided cost estimates produced by PROSYM avoided cost estimates, but some sense of the changes is conveyed by the pattern of light red lines in the above graph.

As more solar is added to the mix, and costs are driven down in the middle of the day, it will become increasingly worthwhile to shift some of that electricity from the middle of the day to later in the evening, or the next morning. This can be accomplished through hourly price signals which reflect the changing pattern of costs over time. For instance, as low cost solar energy becomes more abundant, price-sensitive consumers (especially large, energy-intensive industrial consumers) may respond by shifting some of their usage from morning and evening hours (when costs are higher) into the mid-day hours (when costs are lower). Some industrial customers may decide to install storage to given them even more flexibility in responding to these cost differences.

The end result is to drive down costs even when the sun isn't shining. As solar energy becomes more abundant, avoided costs will initially decline in the middle of the day – creating an opportunity to shift some usage away from hours when costs are higher. While the hourly patterns will be different in the summer, the same principles apply – if appropriate prices are adopted, QF competition can effectively drive down costs and retail rates even when the sun isn't shining.

To fully accomplish this, the actual pattern of avoided costs cannot be submerged within a year-round "all hours" QF rate, as the Company has proposed. With granular price

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signals, QF's are given an opportunity (and incentive) to respond to hourly cost patterns which apply within each season. With stronger and more precise price signals, the opportunity and incentive for QF responses to those signals become stronger, and the benefits to society become larger. Well designed, granular prices benefit competitors and society, by encouraging better investment decisions, more efficient operational decisions, and more effective competition.

Granular pricing may sound administratively challenging, but in reality the PROYSM computer model already develops 8,760 hourly avoided cost estimates for each scenario and each year that is modeled. The Company did not include any of this hourly cost detail with its testimony, and it hasn't provided it to the parties in this proceeding, but this information can be used to develop granular QF rates.

Q. CAN YOU PLEASE RESPOND TO THE COMMENTS DR. LYNCH MAKES AT PAGE 41 CONCERNING JOINT AND COMMON COSTS?

A. Yes. Dr. Lynch is mistaken if he thinks I used the term "markup" to imply a payment above avoided cost. Rather, I was using the word "markup" to convey the idea that prices may need to be higher than short-run variable cost, or running costs included in the PROSYM output. This is necessary to ensure recovery of fixed costs – the portion of total avoided costs that is not included in the PROSYM output. The essence of this reasoning was explained in this passage:

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> in markets (like electricity) where joint and common costs are pervasive, total costs cannot be recovered using pure marginal cost based prices. Instead, prices must include a markup above marginal cost, to provide a mechanism for the recovery of joint and common costs. The cost recovery pattern is clear and consistent across all types of markets where joint costs exist: recover the variable direct costs incurred by producers – short run marginal costs – plus a contribution toward their otherwise unrecoverable indirect, joint and common costs.[15]

The remaining discussion in my testimony is rather technical, showing how joint and common costs are recovered under a variety of different circumstances, and perhaps Dr. Lynch found it somewhat confusing. However, nothing in that discussion was intended to suggest or imply that a markup above avoided cost is needed. I was attempting to explain why QF's should be paid more than just the short-run variable costs they cause to be avoided (the fuel that is not burned when QF energy displaces energy that would otherwise have been purchased or generated using one of the utility's existing generating units). Under PURPA all of the costs that can be avoided should be considered – not just fuel costs. Clearly, this includes capital-related costs that need to be incurred in order to have the ability to burn fuel or generate electricity. While these capital-related costs can be viewed as fixed or unavoidable in the short-run, they are nevertheless highly relevant to this proceeding, since they can and will be avoided as more solar energy is provided by QF's.

15 Direct Testimony of Ben Johnson Docket No. 2018-2-E, Pages 105-106.

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Q. CAN YOU PLEASE RESPOND TO DR. LYNCH'S COMMENTS AT PAGE 41 CONCERNING SUMMER AND WINTER PEAKS?

A. Yes. Dr. Lynch's reasoning is reproduced below:

> If SCE&G has to build a combined-cycle unit to meet its winter peak, but which also satisfies the need for summer capacity, then the fixed costs are incurred. In contrast, adding solar capacity, which only has an impact on capacity in the summer, does not avoid any of those fixed costs.[16]

There are three reasons why this line of argument is flawed.

First, there is no evidence that SCE&G will ever have any need "to build a combined-cycle plant to meet its winter peak" or that this would be an appropriate, cost-effective choice. To the contrary, there are better, less costly options for accommodating the infrequent, relatively short duration peaks that sometimes occur during cold weather. These options are much more logical, and less costly, than building a new combined cycle plant. Many of these options are classified as demand side solutions – which is particularly apt, since the Company's concern with meeting its winter peaks is primarily a demand-side issue (uncertainty concerning how customers will respond to severe winter weather conditions). Demand-side options include the Standby Generator Program, Interruptible Load Generator Program, Real Time pricing, Time of Use rates, and a Winter Peak Clipping Program.[17]

16 Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Pages 41-42.

17 SCE&G 2018 Integrated Resource Plan, pages 15-16.

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Second, the Company is summer-peaking, not winter-peaking. This was explained in the Company's 2017 Integrated Resource Plan:

> SCE&G usually peaks in the summer as seen in the following chart. This is reasonable for several factors. First, the climate in SCE&G's service area is generally hotter in the summer than colder in the winter in the sense that kWh sales are about 15% higher in the summer than winter. Second, the penetration of air-conditioners among SCE&G's customers approaches 100% since there are no real substitutes for electric air-conditioners at present. Finally, a large number of electric customers heat their homes and/or businesses with natural gas. Results of the peak demand forecast methodology used herein show that the general pattern of higher summer peaks relative to winter peaks will continue.[18]

Similar language appeared in earlier editions of the Company's IRP.[19] While some of this language was removed from the 2018 IRP, the underlying facts and logic continue to be valid and applicable, and the Company's system continues to be primarily summer-peaking. This was visually demonstrated by the four graphs included in my direct testimony at pages 111-114. It is worth noting that Dr. Lynch has not disputed any of the data shown in these graphs, nor did he attempt to rebut the conclusions I drew from these graphs, including this one:

> The Company is primarily a summer-peaking utility, the demand for electricity is generally stronger in the summer than in the winter, and both common sense and economic theory tell us that capacity costs should mostly be recovered from customers who are using electricity during high demand periods in the summer...[20]

18 SCE&G 2017 Integrated Resource Plan, page 3.

19 See, for example, SCE&G 2015 Integrated Resource Plan, pages 3-4.

20 Direct Testimony of Ben Johnson, Docket No. 2018-2-E, Page 114.

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Third, although solar capacity is particularly beneficial during the summer – because that is when peak capacity needs are the greatest – solar capacity is also beneficial (and helps avoids capacity costs) during other parts of the year. Most obviously, solar capacity has a beneficial impact on system capacity during spring and fall daytime hours. Capacity is needed during daytime hours in these shoulder seasons, because this is when coal-fired and other base load generating units are often scheduled for routine maintenance, inspections, and overhauls. This is also the time of year when nuclear capacity is sometimes unavailable, due to refueling. Accordingly, it is simply not correct to assume, as Dr. Lynch does, that "adding solar capacity ... only has an impact on capacity in the summer."[21]

Q. CAN YOU PLEASE RESPOND TO THE TESTIMONY AT PAGE 42 WHERE DR. LYNCH DEFENDS PAYING DIFFERENT RATES TO SOLAR AND NON-SOLAR GENERATORS?

A. Yes. Dr. Lynch never attempts to refute the reasoning I offered, that different technologies can all be paid the specific costs they actually avoid, using the same QF tariff, provided it reflects hourly and seasonal cost patterns. If a solar QF provides power during hours (like summer afternoons) when avoided costs are high, the rate it receives should reflect that benefit. Similarly, if some of its power is provided during hours when avoided costs are lower (like mid-morning on a winter day) the QF rate should be lower, to reflect that fact.

21 Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Pages 41-42.

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There is no need to discriminate between different technologies. Wind, hydro, biomass, cogeneration, and other qualified technologies all have different operating characteristics, yet they can all be appropriately compensated using a single technology-agnostic tariff, if the tariff adequately reflects the hourly and seasonal pattern of avoided costs. This is already being accomplished with the existing QF tariff, although further improvements and refinements could be achieved by increasing the degree of granularity – as I just discussed.

Q. WHY IS A TECHNOLOGY-AGNOSTIC APPROACH BETTER?

A. One reason is that there are many different technologies, each with different characteristics. Attempting to anticipate all of the potential technologies that could be used by a QF, and tailoring a specific rate to match the characteristics of that technology is a cumbersome approach that is fraught with difficulties. Assumptions that are appropriate for one hydro plant may not be as accurate, or appropriate, when applied to a different hydro plant. The same is true for cogeneration plants, wind generators, and other technologies. Each plant will have its own unique characteristics – some of which won't be determined until the project is actually constructed and operated. In the case of a cogeneration plant, for example, the volume and timing of electrical output may be intertwined with the unique operating characteristics of the "host" manufacturing or other industrial process.

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A second problem with technology-specific rates is that this approach will inevitably tend to be backward-looking. The characteristics of new technologies are – by definition – not well known or well understood. Requiring technology-specific rates to be adopted or negotiated before a QF is allowed to experiment with a new technology will inevitably impose additional regulatory uncertainty and costs, which will discourage innovation and competitive risk taking.

A third problem with technology-specific rates is the high risk of inadvertently discriminating for or against particular technologies, and the competitors interested in pursuing those technologies. A technology-agnostic approach is more likely to provide a "level playing field."

Q. DO ALL SOLAR QF'S HAVE THE SAME CHARACTERISTICS?

A. No. For instance, the pattern of hourly output will depend on whether the facility tracks the sun, or a fixed array is used. Output can also vary depending on other factors, including the specific geographic location. Comparing data from different weather stations, it is apparent that every location has its own unique micro-climate. Although differences are often very subtle, they do exist. For instance, some potential QF locations may have more cloud cover than others, or the cloud cover might be more frequently experienced in the morning in one potential QF location, and more frequently in the afternoon in a different location.

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Q. ARE INDIVIDUAL NEGOTIATED RATES THE BEST WAY TO DEAL WITH DIFFERENT QF CHARACTERISTICS?

A. No. Negotiated rates can sometimes be useful in dealing with unique circumstances, but they are not a viable alternative to well-designed, technology-agnostic standard offer tariffs. Granular standard offer rates that reflect hourly and seasonal avoided cost patterns are well suited to all technologies. They allow each QF to receive payment consistent with its actual output characteristics and the corresponding level of avoided costs. Standardized, granular rates also allow the QF to anticipate how their revenues will vary depending on each project's specific technology, location, and other details that are within the QF's control. In contrast, with negotiated rates some of the responsibility for analyzing these issues will lie with the utility. This will make the negotiations more complicated, and potentially more acrimonious. In addition, a circularity problem could arise: the offered rate may depend on the project location, technology and design, but decisions concerning the optimal location, technology and design may depend on what rate will apply (and what revenues will be generated) under each potential variation.

It is also important to remember that utilities may not be eager to co-operate with QF's during the negotiating process, and they won't always be focused on finding "win-win" solutions. Experience demonstrates that utilities can sometimes be uncooperative or slow to offer information. If a utility chooses to be intransigent, it may be easier for the QF to walk away from the negotiation to pursue opportunities in another state, rather than

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continuing to pour time and energy into seemingly futile negotiations. The "walk away" option may sometimes seem attractive from the utility's perspective, but it is not attractive from an economic development or public policy perspective.

Q. NEGOTIATED PURCHASED POWER AGREEMENTS ARE COMMON. DOESN'T THIS SUGGEST NEGOTIATED RATES ARE BETTER THAN STANDARD OFFER RATES?

A. No. Even when rate negotiations are successful, those negotiations may reflect the existence of a standard offer rate, or the application of a well-understood and long-established methodology used in preparing the standard offer rate. Even if the QF isn't willing to accept the standard offer rate, it provides a useful reference point. This allows the negotiators to focus on quantifying appropriate adjustments to the standard offer rate, in order to reflect the project's unique characteristics and circumstances.

Without the existence of a standard rate option, QF's may be forced to choose between the time consuming and costly arbitration process (under PURPA, the Commission functions as an arbitrator when negotiations break down) or walking away from the project and investing in another state. Forcing QF's to negotiate rates would make it more costly and burdensome to build QF projects in South Carolina – creating regulatory uncertainty and discouraging investment. Avoiding these uncertainties and barriers to

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entry is particularly important in the context of emerging technologies, like solar + storage.

Q. WHY IS SOLAR + STORAGE IMPORTANT?

A. Solar + Storage is becoming increasingly viable from both an economic and technical perspective. Academic researchers have been pursuing technological advances, and large investments are being made by manufacturers attempting to drive down costs and expand the market for large-scale batteries. The potential exists for significant cost reductions over the next five to ten years, as a result of intense competition between different manufacturers and different technologies, together with increased economies of scale and continued movement down the "experience curve."

This article excerpt provides some sense of the status of competition between different storage technologies:

> Flow batteries have made strides recently in bringing down costs and improving efficiencies, but they are going to have a tough time competing with the entrenched market leader: lithium-ion batteries.
>
> More than half of the 1,280 MWh of worldwide battery installations on the power grid since 2010 have been li-ion batteries, according to Department of Energy data. Looking at just 2015 and 2016, that share rises to 60%. In the United States, li-ion has an even bigger market share at 78% since 2010 and 97% since 2015.
>
> ...
>
> But it seems that just about every other week, researchers announce advances they say will make flow batteries cheaper, safer and more

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> competitive when stacked up against li-ion batteries. There have [also] been more real-world advances, such as Primus Power's recent announcement that it has begun production of a flow battery that the company says can last for 20 years and costs 50% less than conventional li-ion battery systems.
>
> ...
>
> Analysts Eric Selmon and Hugh Wynne concede that li-ion batteries compete with several other commercially deployed battery technologies that have performance characteristics better suited for utility-scale storage.
>
> Flow batteries and sodium sulfur batteries, for instance, have longer discharge times and life spans. [but] li-ion batteries have the momentum of economies of scale and a rapidly declining cost curve behind them.[22]

Discussion at a recent industry conference suggests many experts believe we are already past a "tipping point" that will lead to widespread, large scale deployment of energy storage systems:

> "I think we're at or past that tipping point," responded Andy Marshall, practice director for distributed energy resource management at Landis & Gyr. ... On Dec. 1... Tesla turned on a 129-MWh lithium ion battery, the world's largest, to help the nation's fragile electric grid.[23]

Praveen Kathpal, vice president of a storage technology company agreed:

> "The tipping point we see in storage is really meshing with some of the other megatrends facing our industry right now. We have the accelerated growth in renewables, and we also have the electrification of more sectors including transportation."

22 Utility Dive, March 14, 2017. https://www.utilitydive.com/news/despite-technological-advances-flow-batteries-struggle-against-market-gian/437399/

23 RTO Insider, December 11, 2017. https://www.rtoinsider.com/energy-storage-gridconnext-82139/

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> Kathpal predicted new storage technologies will break below the current pricing floor for lithium ion. "So, 10 years from now, do I think we'll have a commercially available storage technology that's below $100/kWh? Sure."[24]

The lead research engineer from another energy technology firm was equally optimistic:

> More and more markets continue to value the fast-ramping and bidirectional capability that energy storage provides. And I think as systems continue to decline in cost, we will compete in more and more markets. A lot of the market prices basically clear according to the natural gas price. So it's really just a matter of getting renewables plus storage to below that threshold in more and more places.

However, other participants noted storage costs are currently higher than some other alternatives, like demand-side management, at least in some situations:

> Richard Brody, director of sales and marketing for Lockheed Martin Energy's energy storage unit, said storage is still relatively expensive when compared with energy efficiency and demand response.
>
> ...
>
> But he is nevertheless bullish on storage. "In terms of the tipping point – oh yeah, we're passed it. This is a rapidly growing market.
>
> We're seeing very strong growth in interest in doing large solar and wind coupled with storage. Most of the large developers we're working with aren't contemplating any large development of solar – and increasingly wind – without some way to firm it up with a fairly significant storage system."

24 Ibid.

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Q. HOW DOES SOLAR + STORAGE FIT WITH THE COMPANY'S PROPOSED TARIFF CHANGES IN THIS PROCEEDING?

A. It doesn't. None of the changes proposed by the Company align as well with solar + storage as the existing QF tariff. The uniform "all hours" rate for solar is obviously not viable, since the QF would receive the same (or less) revenue from a solar project that includes storage than from one that doesn't include any investment in storage.[25] If the negotiated rate option were applicable to solar projects that include storage, that option would also not be viable, because of the problems just mentioned, including the circularity problem. There are a wide range of possible storage configurations, each with different characteristics. Without knowing how much will be gained by storing power at one hour and using it at another hour, it will be impossible to evaluate the pros and cons of the different technologies and other investment options.

Consistent with the intent of PURPA, South Carolina QF's should be allowed to take calculated risks investing in new storage technologies.[26] However, without a reasonable degree of regulatory certainty with respect to how hourly avoided cost differentials will be passed through to QF's, it becomes impossible to meaningfully evaluate investments that allow power to be generated in one time period and sent to the grid in another. Telling a QF that the rate is "subject to negotiation" is no better than saying that the

25 Revenues would actually decline if a battery technology is used, because of the energy losses that occur each time the battery is charged and discharged.

26 Unlike rate base investments, the risks will be borne by the QF's investors, not by retail customers.

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potential benefit from investing in storage investments is completely unknown. Adding that sort of regulatory uncertainty on top of all the other risks and uncertainties associated with new technologies will greatly discourage QF investments in storage. In contrast, with technology-agnostic granular QF rates each competitor will be able to make their own decisions about the future trend in storage technology costs, the optimal timing for making storage investments, and all of the other project-specific decisions that need to be made when evaluating a solar project with a 30+ year economic life.

With appropriate QF rates, some competitors may attempt to achieve an "early mover" advantage by obtaining operational experience with storage from the outset of some projects. Others may initially construct a solar-only facility, while planning to add storage once the pattern of hourly avoided cost differentials (as reflected in their contract) increases sufficiently to justify investing in storage. Choosing between these strategies or making other storage-related investment decisions will be nearly impossible if the Company's tariff proposals are accepted in this proceeding – including the change to a negotiated rate environment or the change to a uniform "all hours" rate.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY WHICH WAS PREFILED ON APRIL 4, 2018?

A. Yes.

MR. WHITT: Mr. Chairman, Dr. Johnson is available for questions.

CHAIRMAN WHITFIELD: Thank you, Mr. Whitt. Mr. Elliott.

MR. ELLIOTT: No questions. Thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: Ms. Ottenweller.

MS. OTTENWELLER: No questions. Thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: Mr. Bateman?

MR. BATEMAN: No questions.

CHAIRMAN WHITFIELD: And Mr. Burgess.

MR. BURGESS: No questions of this witness.

CHAIRMAN WHITFIELD: Okay. We're down to Commissioner questions for Dr. Johnson. And I'm sorry for calling you "Mr." earlier.

Commissioners? Commissioner Howard.

EXAMINATION

BY COMMISSIONER HOWARD:

Q Dr. Johnson, I guess what I – are you recommending a time-of-use payment for distributed energy?

A Yes, I'm in agreement with the ORS witness, Brian Horii, who just testified a few minutes ago. The best solution for some of the issues we're dealing with here is to offer hourly, precise rates. And these are very

sophisticated buyers and sellers. The company is certainly sophisticated enough to understand an hourly rate, and the sellers, the QFs, are certainly sophisticated enough or will learn quickly to handle the complexities. So the normal concerns you would have in a residential context about an overly complex rate simply don't apply here. You're dealing with multimillion-dollar investments. As I recall, the testimony was a few weeks ago in the ex parte proceeding that we're dealing with $5 billion – "billion" with a B – of investments. The people who are investing that money are perfectly willing to respond to an hourly rate pattern that accurately reflects QF avoided costs hour-by-hour.

Q Are you aware that the company has one now and has very few takers?

A I'm not familiar with a buy-up rate on it, but I know that time-of-use rates have been widely used. Generally, when they're most successful is when they're targeted at industrial customers who have the time and care enough to understand it. There are states – I think New York might be one – that has basically real-time pricing, where basically every hour is potentially a different rate and a customer goes to a great deal of effort to model and adjust their industrial process

based on cost of energy from hour to hour. So it does occur some places, even if it isn't happening here.

COMMISSIONER HOWARD: Thank you, very much.

CHAIRMAN WHITFIELD: Commissioner Hamilton.

COMMISSIONER HAMILTON: Thank you, Mr. Chairman.

EXAMINATION

BY COMMISSIONER HAMILTON:

Q Dr. Johnson, in South Carolina, our cost of service is based on cost of service, not value of service. Why should Distributed Energy Resource providers be compensated under this method?

A The – if we're referring to PURPA, it is also a cost-of-service-based mechanism. The only difference is that it looks at incremental costs or avoided costs, rather than embedded costs. So what happens is the QF rates are supposed to be capturing and passing through to the tariff an accurate measure of the costs that can be avoided.

I speak of value at points in my testimony because I think it's helpful in understanding the connections in a competitive market – value and cost both come into play; commonly, it's called supply and demand. So they're both important, but under PURPA the primary factor that is regulated is the rate that would be paid

to the solar farm, and that rate is supposed to be based upon cost that's avoided, which is why being accurate about that is so important. That's why so much effort is being put into this proceeding and you're listening to all this testimony, because there's obviously some disputes about how to accurately calculate those avoided costs.

Q Do you have some examples of where your system is in use?

A Well, in general, the approach that this Commission adopted last year is superior to the one that's being proposed this year. That approach that was used last year – which had like a four-hour block, as I recall, for capacity, and in the afternoon I think it might've been from 2 to 6, and then at a similar narrow block in the winter but it's in the morning – has also been used, similar patterns have been used in North Carolina and I think some other states. So having a modest degree of time-of-day precision is already common practice and certainly has been the practice of this Commission. I would urge you to go further. Because of the concerns of the duck curve and because of the concerns about – and we have, I guess, another 1000-2000 megawatts, or more, of solar that investors are ready to put into the State, in the queue. And to properly evaluate those

investments and to ensure that the customers get the maximum benefit from that, we want to have – I believe – more accurate prices. At a minimum, you want to retain the four-hour block, the time-of-use approach you've had historically. Again, I agree with Mr. Horii the preferable approach is to get even more precise, and that in turn will assure that, over time, investments that are being made are properly reacting to actual conditions as they evolve over time.

COMMISSIONER HAMILTON: Thank you, Dr. Johnson.

Thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: Thank you, Commissioner Hamilton.

Any other Commissioner questions for Dr. Johnson? Commissioner Fleming.

COMMISSIONER FLEMING: Yes.

EXAMINATION

BY COMMISSIONER FLEMING:

Q Did – what is your opinion on negotiated rates?

A I think that 35 years with almost no successful negotiation tells you the answer. Telling investment companies that they have to first negotiate to determine whether or not a project is worth building is a major barrier to investment. There's already a lot of upfront

investments that a company has to make in order to put in a solar farm or a hydro plant or anything of that sort. You have to tie up land, you have to – if it's hydro, you have to get licensing. There's a whole series of things you have to do. And if, at least, you have an estimate of what your revenues are going to be, those risks become somewhat manageable. Still very high risk to decide whether to buy a piece of property, you know, all the uncertainty. But if you have to negotiate and you have no idea what the rate's going to be, it just creates so much uncertainty, the easiest thing to do is to walk away and go to another state.

So I'm not against negotiated rates, and I think they can work in some special situations, but the primary benefit is if you already have a standard offer rate that the investor can look at and say, "Okay. Worst case, I'm going to get that standard offer rate. I think my project has special qualities about it," maybe ancillary services or other reasons, "that I ought to be able to negotiate a better rate. I can, say, reduce transmission costs, perhaps, and try to convince them in negotiations to give me compensation for the costs I'm avoiding on the transmission system." If you have the standard offer rate as a benchmark, those negotiations have a little bit better chance of

succeeding. But again, in general, allowing a monopolist to decide how much effort they're going to put into negotiations and what rate to offer, to me, is not a realistic solution.

COMMISSIONER FLEMING: Thank you.

CHAIRMAN WHITFIELD: Thank you, Commissioner Fleming.

I don't see any other questions.

EXAMINATION

BY CHAIRMAN WHITFIELD:

Q I've got one quick question for you Dr. Johnson, before we break, here. And, again, I apologize about using "Mr." I see your credentials show you've got a Ph.D. from Florida State, so we'll call you Dr. Johnson in here – and we won't hold it against you for being a Seminole, either.

A Okay. At least this year we did a little better in basketball than usual.

Q Yes, sir. Yes, sir. One quick question for you. You provided a fairly lengthy discussion of the risks associated with fossil-fuel generation, primarily the variability of fuel prices.

A Yes.

Q There's been some other discussion here in the case about the important risk of potential loss of service.

I don't know from your testimony, but it's been discussed earlier in this case already about the loss of services, such as outages or the loss of quality of service, such as voltage variations, frequency instability, that sort of thing. Does the intermittent nature of solar generation increase or decrease this risk?

A Properly evaluated, considering the diversification that actually occurs, I don't think it increases it. But the real question goes back to the problems with the expansion plan. The expansion plan does not properly and adequately take into account the growth in solar that is happening. They've assumed very, very limited choices that they analyze. They basically analyzed two different combined-cycle plants, one that's a used one that they'd be purchasing of 504 megawatts and that they're assuming that they'll purchase, and the other one is 540 megawatts a couple of years later. Those plans provide a little bit of additional benefit in terms of flexibility to offset the problems with their coal plants, but they're not the optimal choices. There's other choices: Targeted purchases would be helpful; I believe hydro is available that is extremely flexible, just like their pumped storage is. They haven't been pursuing that.

So it's clear to me that the expansion plan, which is the fundamental foundation of the entire DRR method is not thoroughly enough thought through, does not have the flexibility that would be optimal for customers, and if you were to implicitly endorse that plan, I think it would be a great mistake because it would be very costly for customers, given the solar that's coming on-line, given the other things that are happening in the industry.

Q And you talked about some of the other avoided costs, the capital investment and some of that – those projects. You mentioned even not having to pay property taxes or other things that would be –

A Avoidable?

Q – avoidable, yes, sir. But back to the intermittent nature of solar generation, what about the risk – back to the risk – to the frequency, maintaining the proper megahertz of the frequency on the grid, those type things: outages, voltage variations, all those sorts of things. Could I hear you kind of get back to that just a little bit, your answer on that?

A Yeah. The succinct part of my answer was I don't think it's a serious problem. Certainly, there are some differences in characteristics, as you bring in solar, that are different than the characteristics of, say,

coal plants, for example. But I don't think, on balance, they're a problem. First of all, again, I alluded to diversity; it's very important to keep that in mind. When you oversimplify things and look at a single solar farm in a single year, and then try to extrapolate from that, you get a really flawed impression. If you look at the drawings in front of you, in the exhibit that Dr. Lynch provided, it shows these jagged patterns but that's very specific to that particular – you know, when the clouds moved over that particular solar farm. That same cloud is going to be over at different solar farm at a different time, so the actual pattern that you'll see on a diversified system is much smoother, which, in turn, means that that voltage and other issues we're talking about is much less of a concern.

But I do think it is fair to say that – oh, another point. A similar example is, again, you've got trade-offs. Most of these plants are pretty small. Under PURPA, they're no more than 70 megawatts; some of them are as little as 5 megawatts or 2 megawatts. Again, you get diversity risks. If a solar plant loses its inverter or somehow, you know, drops off the system, you're dropping 5 megawatts – it's trivial – whereas the exact analogous type of risk that happens with a large

CC or coal plant, you're potentially looking at hundreds of megawatts.

So, again, there's offsetting risk; on balance, I don't think we're adding any risk due to the intermittency of solar, particularly because the main thing that happens is the pattern of in the morning it starts coming up, peaks in the middle of the day, and comes back down. That particular pattern is very predictable.

And so, given that it's predictable, the optimal strategies are right in front of us; it's simply a matter of, step one, take the existing Fairfield Pumped Storage unit and operate it differently than they have historically done, by using that as a load-following unit to help smooth out those fluctuations and to deal with the question of the ramping problems for their coal units in the morning and at the end of the day. Perfectly obvious solution. Similarly, to the extent they might be worried about excess generation in the middle of the day, potentially – you know, they talked about the idea of you have certain minimum load units that you're trying to keep up during the middle of the day, say, a coal unit – the answer is very simple: start using some of that power to refill the pumped storage in the middle of the day.

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So, again, there are very straightforward operational solutions to these issues. I don't think it would be fair to say, on balance, that bringing in renewable solar creates problems. It simply creates a different set of challenges that have answers that are pretty straightforward and that ought to be reflected in the expansion plan, but have not yet been incorporated into that plan.

Q So to boil it all down, your answer is, really, any increases would be, in your words, slight or insignificant, and that the company has resources, such as pumped storage, hydro pumped storage up at Fairfield, and other resources, to, as you say, smooth this out?

A Yes. And to the extent there are some issues that they do not fully have – and I want to be clear, because we're talking about over a 15- or 30-year period. These investments are 30 years' expected life of the solar farm. To the extent, in the outer years beyond what's available with, for example, Fairfield Pumped Storage, I believe there are straightforward answers for those time periods, as well, and that's why I talked about targeted purchases to give them the maximum flexibility, rather than committing to a long-term 40-year investment in a combined-cycle plant. It'd be much more prudent to make shorter-term purchases for the next five or ten years

and watch what happens with storage, watch what happens with the QF industry. To the extent they start reacting and building a lot of storage, you don't need, necessarily, a combined-cycle plant to meet a peak that may have eventually shifted to 7 or 8 o'clock at night, that the solar farms may be meeting that peak with their storage units.

So, again, the economic trade-off between a short-term purchase, targeted purchase, readily available from Georgia or PJM – or there's capacity available in North Carolina, as well – a targeted purchase that gives the company a lot of flexibility further contributes to why I said, on balance, none of those issues you raise strike me as a reason to be concerned or to say we should not have solar, we need to slow down, or we need to try to discourage solar investment.

CHAIRMAN WHITFIELD: Thank you for your answer.

I don't see any further questions from Commissioners. Mr. Whitt, is there any redirect?

MR. WHITT: Mr. Chairman, I have no redirect. But I would like to note that – I'd like to beg your indulgence for two minutes, less than two minutes maybe, to place a closing note on the record, when appropriate.

CHAIRMAN WHITFIELD: Mr. Whitt, if you could hold that, we're going to break now, unless you had any redir- – I'll give you that opportunity. We're going to break now for lunch. The Commission does have a meeting at 2, and we do have a transportation case immediately following that. So, at this – do you want him to still be on the stand when you have this statement?

MR. WHITT: No, Mr. Chairman. In fact, I think we want to excuse him, I think.

CHAIRMAN WHITFIELD: Okay.

MR. WHITT: He's from Florida; he's got to get to a flight.

CHAIRMAN WHITFIELD: Dr. Johnson, you may step down and be excused.

[WHEREUPON, the witness was excused.]

And, Mr. Whitt, when we resume, I'll give you your opportunity –

MR. WHITT: Thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: – and we will come back with the other ORS panel. I cannot give any of you in here an exact time, because I don't know when the transportation case will be over, but we would ask you to hang around past our meeting and past the transportation case, and we will start up as

soon as possible.

MR. WHITT: Thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: Thank you. We're in recess.

[WHEREUPON, at 1:40 p.m., a lunch recess was taken, to allow also for separate scheduled proceedings to be held prior to recommencement of the proceedings herein at 3:10 p.m.]

A F T E R N O O N P R O C E E D I N G S

CHAIRMAN WHITFIELD: Please be seated. I'll call this hearing back to order. And I believe, when we left off, Mr. Whitt, you had stated you wanted to make a statement. I'm assuming that's a closing? Is that great.

MR. WHITT: I apologize, Mr. Chairman. I wasn't mic'd up, and I'm still not mic'd up [indicating].

CHAIRMAN WHITFIELD: No, you still aren't.

MR. WHITT: I wasn't mic'd up. I said I wanted to make it when appropriate. I did not mean out of order. I apologize.

CHAIRMAN WHITFIELD: Well, you certainly will have that opportunity to make a closing statement, and we'll take closing statements at the end, and you will certainly have your opportunity.

MR. WHITT: I appreciate that, and I apologize.

CHAIRMAN WHITFIELD: All right, sir.

With that, we're going to turn to the Office of Regulatory Staff for you to present your last panel.

MS. PITTMAN: Thank you, Mr. Chairman. I would like to call ORS's second panel up to the

stand; that's Ms. Gaby Smith and Mr. Michael Seaman-Huynh.

CHAIRMAN WHITFIELD: Please come forward, Ms. Smith and Mr. Seaman-Huynh.

[Witnesses affirmed]

THEREUPON came,

G A B Y S M I T H ,

M I C H A E L L . S E A M A N - H U Y N H ,

called as witnesses on behalf of the South Carolina Office of Regulatory Staff, who, having been first duly affirmed, were examined and testified as follows:

DIRECT EXAMINATION

BY MS. PITTMAN:

Q Ms. Smith, please state your full name and occupation.

A [SMITH] My name is Gaby Smith. I'm an audit manager for the Office of Regulatory Staff.

Q Are you the the same Gaby Smith who prefiled 15 pages of direct testimony on March 23, 2018?

A [SMITH] Yes, I am.

Q Do you have any changes or corrections to your prefiled testimony?

A [SMITH] Yes, I do. Page 12-of-15, lines 17 and 21, the word "over" should be replaced with "under."

Q With those changes, if I asked you the questions contained in your prefiled testimony today, would your

answers be the same?

A [SMITH] Yes, they would.

MS. PITTMAN: Mr. Chairman, ORS asks that the prefiled direct testimony of Gaby Smith be entered into the record as if given orally from the stand, along with the corrections that Ms. Smith just mentioned.

CHAIRMAN WHITFIELD: Ms. Smith's prefiled direct testimony, along with the corrections she just mentioned, will be entered in the record as if given orally from the stand.

MS. PITTMAN: Thank you.

BY MS. PITTMAN:

Q Ms. Smith, did you also prepare or cause to be prepared 12 pages of exhibits marked GS-1 through GS-9, which were attached to your prefiled testimony?

A [SMITH] Yes.

Q Do you have any changes or corrections to your exhibits?

A [SMITH] I do not.

MS. PITTMAN: Mr. Chairman, ORS asks that Exhibits GS-1 through GS-9, which were filed as attachments to the prefiled direct testimony of Ms. Smith, be marked as the next composite hearing exhibit.

CHAIRMAN WHITFIELD: Ms. Smith's Exhibits GS-1

through GS-9 will be marked as Hearing Exhibit No. 14.

[WHEREUPON, Hearing Exhibit No. 14 was marked and received in evidence.]

MS. PITTMAN: Thank you.

BY MS. PITTMAN:

Q Ms. Smith, did you prepare a summary of your direct testimony?

A [SMITH] Yes, I did.

Q Would you please present that to the Commission?

A [SMITH] Sure.

Good afternoon, Mr. Chairman, and members of the Commission.

The purpose of my testimony is to present the results of the ORS Audit Staff's examination of SCE&G's books and records as they pertain to the company's operation of the fuel adjustment clause in the current filing.

ORS Audit Staff examined and verified the monthly over/underrecovery balances as recorded by the company for the actual 12-month review period that ended December 2017. Based on our review, ORS agrees with the balances and adjustments put forth by the company as of December 2017.

This concludes my summary.

MS. PITTMAN: Thank you.

[PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED DIRECT TESTIMONY {W/CORRN'S} OF GABY SMITH FOLLOWS AT PGS 859-874]

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THE OFFICE OF REGULATORY STAFF

DIRECT TESTIMONY & EXHIBITS

OF

GABY SMITH

MARCH 23, 2018

DOCKET NO. 2018-2-E

Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company

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DIRECT TESTIMONY AND EXHIBITS OF

GABY SMITH

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-2-E

IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Gaby Smith. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina 29201. I am employed by the State of South Carolina as an Audit Manager, in the Audit Department of the South Carolina Office of Regulatory Staff ("ORS").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Science Degree in Accounting from the University of South Carolina in May 2006. Prior to joining ORS, I held a variety of positions in finance, accounting, and auditing. I began my employment as an auditor with ORS in July 2009 and have participated in various cases involving the regulation of electric, telecommunication, water and wastewater utilities. I have previously testified before the Public Service Commission of South Carolina ("Commission") on several Fuel Adjustment Clause ("FAC") filings, as well as water, wastewater, and electric rate cases.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the results of ORS Audit Staff's

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examination of the books and records pertaining to South Carolina Electric & Gas Company's ("SCE&G" or "Company") operations under the FAC. The current fuel examination covered the actual period of January 2017 through December 2017 ("actual review period") and four (4) estimated months from January 2018 through April 2018 ("estimated review period").

Q. WHAT WAS THE PURPOSE OF THIS EXAMINATION?

A. The purpose of this examination was to verify that the Company's accounting practices in computing and applying the monthly FAC comply with S.C. Code Ann. § 58-27-865.

Q. WHAT WAS THE SCOPE OF ORS'S EXAMINATION?

A. ORS Audit Staff examined and verified the monthly fuel adjustment factor calculations and the fuel recovery balances recorded in the Company's books and records. The Audit Staff's examination consisted of the following:

1. Analyzing the Fuel Stock Account

ORS's analysis of the fuel stock account consisted of verifying receipts to and issues from the fuel management system to the general ledger, examining monthly fuel charges originating in fuel accounting, and ensuring that only proper charges were entered in the Company's computation of fuel costs for purposes of adjusting the base fuel factor.

2. Sampling Receipts to the Fuel Stock Account

ORS's review of receipts to the fuel stock account consisted of examining and testing selected transactions which support additions to the account. Each selected transaction examined was tested for mathematical accuracy and vouched to a

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commodity received report, corresponding waybill, supplier invoice, and freight study detail report. Transactions were then verified to a fuel management system payment voucher to verify payment of the correct amount to the vendors.

3. Verifying Charges to Nuclear Fuel Expense

ORS verified the amounts of nuclear fuel expense to the books and records for the actual review period. Additionally, the accuracy of these amounts was verified to the Company's amortization schedules.

4. Verifying Purchased and Interchange Power Fuel Costs

ORS verified the Company's purchased and interchange power fuel cost, kilowatt-hour ("kWh") purchases, and kWh sales for the actual review period to various "energy received" and "energy delivered" summary reports, purchases, sales, and interchange power schedules, and monthly invoices, on a sample basis. ORS recomputed the Company's sales and purchases for the actual review period. The purchased and interchange power amounts for the actual review period and the resultant (over)/under-recovery monthly deferred fuel amounts for the period reflect calculations that conform to S.C. Code Ann. § 58-27-865, the statute addressing fuel costs related to purchased power. Subsection (A)(2)(b) of this statute states that the total delivered cost of economy purchases, including, but not limited to, transmission charges, are included in purchased power costs if those purchases are "less than the purchasing utility's avoided variable costs for the generation of an equivalent quantity of electric power." ORS verified economic purchases were recorded at or less than the applicable avoided costs.

5. Verifying kWh Sales

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ORS verified total system kWh sales, as filed in the monthly fuel factor computation, to monthly class/rate summary reports for the actual review period. The monthly kWh sales figures were then used to determine the fuel cost per kWh sold and the monthly fuel cost adjustment factors.

6. Recalculating the Fuel Adjustment Factors and Verifying the Current Month (Over)/Under Recovery

ORS recalculated the fuel cost adjustment factors for the actual review period utilizing information obtained from the Company's records and verified these total fuel costs to the Company's books and records. In recalculating the monthly factors, ORS divided total fuel costs by total system kWh sales to arrive at fuel costs per kWh sold. The base fuel cost per kWh was then subtracted from the actual fuel cost per kWh sold to compute the current month (over)/under-recovery. The actual current month (over)/under recoveries were then verified to the Company's books and records.

7. Recalculating the True-up of the (Over)/Under-Recovered Fuel Costs

ORS analyzed and recomputed the cumulative (over)/under-recovery of the base fuel costs for the actual review period and (over)/under-recovery for the estimated review period. In addition, ORS recomputed the cumulative (over)/under-recovery of environmental and avoided capacity costs for the actual and estimated review periods as approved in Order No. 2017-246.

Q. PLEASE EXPLAIN THE AUDIT EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. ORS prepared the following audit exhibits from the Company's books and records:

AUDIT EXHIBIT GS-1: TOTAL RECEIVED AND WEIGHTED AVERAGE COST

This audit exhibit details total received cost for the actual review period of $516,825,377 for coal, #2 oil, and natural gas. ORS also computed the weighted average cost of each type of fuel: coal ($82.55 per ton), #2 oil ($1.99 per gallon), and natural gas ($3.57 per thousand cubic feet ("MCF")).

AUDIT EXHIBIT GS-2: RECEIVED COAL – COST PER TON COMPARISON

This audit exhibit details the received cost per ton of coal for each month of the actual review period for SCE&G, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC. For comparison purposes, ORS has shown the invoice cost per ton, freight cost per ton, total cost per ton, and the cost per thousand British thermal units ("MBTU").

AUDIT EXHIBIT GS-3: BURNED COST – CONSUMED GENERATION

This audit exhibit details the per book cost of fuel burned for electric generation during the actual review period. The burned cost of each class of fuel is shown separately along with its percentage of total burned costs. These costs are used in the computations of the base fuel cost component.

AUDIT EXHIBIT GS-4: COST OF FUEL

This audit exhibit details ORS's computation of the total fuel cost applicable to the fuel recovery calculation. There are four (4) components included in this cost, and they are as follows:

(1) Cost of Fuel Burned

(2) Fuel Cost of Purchased and Interchange Power

(3) Fuel Cost Recovered from Intersystem Sales

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(4) Public Service Authority ("Santee Cooper") Credits

Cost of Fuel Burned - This amount is the total cost of all fossil and nuclear fuel burned during the actual review period and used in the base fuel component computation. A detailed breakdown of coal, #2 oil, natural gas, and nuclear fuel can be seen in Audit Exhibit GS-3.

Fuel Cost of Purchased and Interchange Power - This amount is the total fuel cost of monthly kWh purchases from other electric utilities or power marketers.

Fuel Cost Recovered from Intersystem Sales - This amount is the total fuel cost recovery related to kWhs sold during to other electric utilities or power marketers.

Public Service Authority Credits – This amount represents recovery of Santee Cooper's portion of the electric costs at the new nuclear construction site.

AUDIT EXHIBIT GS-5: DETAILS OF THE COMPUTATION OF BASE FUEL (OVER)/UNDER-RECOVERY

This audit exhibit details the monthly (over)/under-recovery of base fuel cost computations for the actual review period as well as fuel costs for the estimated review period. The exhibit also shows the computations of the actual and estimated cumulative (over)/under-recovery balances and various adjustments for January 2017 through April 2018.

AUDIT EXHIBIT GS-6: TOTAL ENVIRONMENTAL COSTS

This audit exhibit details the total environmental costs for the actual review period for sulfur dioxide ("SO_2") emission allowances, nitrogen oxide ("NOx") emission allowances, lime/limestone, and ammonia. Additionally, the percentage of total cost is shown for each environmental component.

AUDIT EXHIBIT GS-7: DETAILS OF THE COMPUTATION OF THE (OVER)/UNDER-RECOVERY OF ENVIRONMENTAL AND AVOIDED CAPACITY COSTS

This audit exhibit details the monthly (over)/under-recovery of environmental and avoided capacity cost computations for the actual review period for SO_2 and NOx emission allowances, lime/limestone, ammonia, avoided capacity costs, and estimates of these costs for the estimated review period. The exhibit also shows the computation of the cumulative (over)/under-recovery balances and various adjustments for January 2017 through April 2018.

Due to the enactment of 2014 S.C. Acts 236 ("Act 236"), the avoided capacity component of certain purchased power costs are now required to be allocated and recovered as a separate component of the overall fuel factor in the same manner as environmental costs.

AUDIT EXHIBIT GS-8: DETAILS OF THE COMPUTATION OF THE (OVER)/UNDER-RECOVERY OF DISTRIBUTED ENERGY RESOURCE PROGRAM ("DERP") AVOIDED COSTS

This audit exhibit details the monthly (over)/under-recovery of DERP avoided cost computations for the actual and estimated review periods. ORS agreed avoided cost components to "bill credit agreement" reports, invoices, journal entry detail, revenue and unbilled revenue reports. DERP avoided costs are further explained in the testimony of ORS witness Johnson.

AUDIT EXHIBIT GS-9: DETAILS OF THE COMPUTATION OF THE (OVER)/UNDER RECOVERY OF DISTRIBUTED ENERGY RESOURCE PROGRAM INCREMENTAL COSTS

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This audit exhibit details the monthly (over)/under-recovery DERP incremental cost computations by month for the actual and estimated review periods. ORS tested selected administrative and general expenses, and recalculated depreciation expense and carrying cost computations. ORS also agreed incremental cost components to "net metering costs" reports, invoices, journal entry detail, revenue and unbilled revenue reports. DERP incremental costs are further explained in the testimony of ORS witness Johnson.

Q. PLEASE EXPLAIN ORS AUDIT STAFF'S COMPUTATION OF THE CUMULATIVE (OVER)/UNDER-RECOVERY OF FUEL COSTS IN EXHIBIT GS-5.

A. ORS Audit Exhibit GS-5 provides details of ORS's calculation of the actual cumulative under-recovery balance through December 2017, and the estimated over-recovery balance through April 2018. The cumulative under-recovery amount as of December 2017 totaled $2,355,695. This amount includes several adjustments which are discussed below. ORS then added SCE&G's estimated under-recoveries of $53,056,195 for January 2018, $3,522,231 for February 2018, $2,394,603 for March 2018, and $3,765,128 for April 2018, and various Company adjustments to arrive at a cumulative over-recovery of $50,536,981 through April 2018. Company witness Rooks' testimony (Exhibit No. ___ (AWR-1)) in this docket reports the same cumulative under-recovery total through December 2017, and the same cumulative over-recovery total through April 2018 as calculated by ORS.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS OR TRUE-UPS DURING EITHER THE ACTUAL OR ESTIMATED REVIEW PERIODS FOR THE BASE FUEL COMPONENT?

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A. Yes. The Company made the following adjustments as shown on Audit Exhibit GS-5:

Adjustment (1) – Fixed Capacity Charges

The Company posted a monthly over-recovery adjustment of $1,583,583 to the computation of the base fuel (over)/under-recovery. This adjustment consists of the Urquhart Plant and the Jasper Plant (Combined Cycle) monthly fixed capacity charges of $673,417 and $910,166, respectively, which are treated, in accordance with Commission Orders No. 2003-38 and No. 2005-2, on a retail basis, as over-recovery fuel entries.

Adjustment (2) – PR-1 Energy Credits

Due to the enactment of Act 236, purchased power avoided energy costs are now required to be recovered through the FAC. A portion of purchased power avoided energy costs is also currently being recovered in base rates. Therefore, the Company made monthly over-recovery adjustments of $691 to prevent double collection of this portion of avoided energy costs.

Adjustment (3) – Company Accounting Adjustments

During the actual review period, the Company recorded the following adjustment:

(3A) – In March 2017, the company made an over-recovery adjustment of $183,187 to account for a true-up in fuel expenses billed by Kapstone for January and February 2017.

During the estimated review period, the Company recorded the following adjustments:

(3B) – In January 2018, the Company made an under-recovery adjustment of $411,384 to account for purchased power payments for October, November and December 2017 that were inadvertently omitted.

(3C) – In February 2018, the Company made an over-recovery adjustment of $113,739,272 to offset base fuel costs with a gain from interest rate swaps.

Adjustment (4) – Unbilled Fuel Cost (Over)/Under-Recovery Adjustments

In both the actual and estimated review periods, the Company reflects monthly adjustments to account for the timing difference associated with kWh sales not yet billed due to the cycle billing process, whereas the FAC process reflects all unbilled fuel transactions (sales and costs) on a full monthly basis.

Q. PLEASE EXPLAIN ORS AUDIT STAFF'S COMPUTATION OF THE CUMULATIVE (OVER)/UNDER-RECOVERY OF ENVIRONMENTAL AND AVOIDED CAPACITY COSTS IN EXHIBIT GS-7:

A. ORS Audit Exhibit GS-7 provides details of ORS's calculation of the cumulative environmental and avoided capacity costs over-recovery balance of $2,272,425 through December 2017. ORS then added estimated under-recoveries of $324,293 for January 2018, $335,912 for February 2018, $408,940 for March 2018, and $267,642 for April 2018, and various Company adjustments to arrive at a cumulative over-recovery balance of $1,051,097 through April 2018. Company witness Rooks' testimony (Exhibit No. ___ (AWR-4)) reports the cumulative environmental and avoided capacity costs over-recovery total through December 2017 as $2,272,425 and the over-recovery total through April 2018 as $1,051,102. The variance between ORS and the Company's ending balance for April 2018 is due to rounding.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS OR TRUE-UPS DURING EITHER THE ACTUAL OR THE ESTIMATED REVIEW PERIODS FOR THE ENVIRONMENTAL AND AVOIDED CAPACITY COSTS COMPONENT?

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A. Yes. The Company made the following adjustments as shown on Audit Exhibit GS-7:

Adjustment (5) – PR-1 Capacity Credits

Similar to Adjustment (2), avoided capacity costs are now also recovered through the FAC. A portion of avoided capacity costs is also being recovered in base rates. Therefore, the Company made monthly over-recovery adjustments of $84 to prevent double collection of this portion of avoided capacity costs.

Adjustment (6) – Company Accounting Adjustment

In March 2017, the Company made an over-recovery adjustment of $3,631 to account for a true-up in reagent expenses billed by Kapstone for the months of January and February 2017.

Adjustment (7) – Unbilled Fuel Cost (Over)/Under-Recovery Adjustments

As discussed for base fuel costs in Adjustment (4), the cycle billing process also affects the recovery of environmental costs. The Company posted monthly adjustments throughout the actual review period and the estimated review period to account for timing differences.

Q. PLEASE EXPLAIN ORS AUDIT STAFF'S COMPUTATION OF THE CUMULATIVE (OVER)/UNDER-RECOVERY OF THE DISTRIBUTED ENERGY RESOURCE PROGRAM AVOIDED COSTS IN EXHIBIT GS-8.

A. ORS Audit Exhibit GS-8 provides details of ORS's calculation of the cumulative DERP avoided cost over-recovery balance of $1,504,687 through December 2017. ORS then added estimated under-recoveries of $119,665 for January 2018, $216,415 for February 2018, $336,503 for March 2018, and $467,905 for April 2018, to arrive at a cumulative over-recovery of $479,920 as of April 2018. Company witness Rooks'

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testimony (Exhibit No. ___ (AWR-6)) reports the over-recovery total through December 2017 as $1,504,690, and through April 2018, reports a cumulative over-recovery total of $479,924. The variances between ORS and the Company's ending balances are due to rounding.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS OR TRUE-UPS DURING EITHER THE ACTUAL OR THE ESTIMATED REVIEW PERIODS FOR THE DISTRIBUTED ENERGY RESOURCE AVOIDED COSTS COMPONENT?

A. Yes. The Company made the following adjustments as shown on Audit Exhibit GS-8:

Adjustment (8) – Company Accounting Adjustments

During the actual review period, the Company recorded the following adjustment:

Adjustment (8A) – Final Billing

In February 2017, the Company made an under-recovery adjustment of $185 to reflect prior year adjustments related to the excess net energy metering ("NEM") credit payments due to closing of customer accounts.

Adjustment (8B) – Utility Scale Test Power

In March 2017, the Company made an under-recovery adjustment of $8,892 to account for December 2016 utility scale test power that was inadvertently omitted from the calculation during that month.

Adjustment (8C) – Excess NEM Credits

In August 2017, the Company made an under-recovery adjustment of $263 to account for July 2017 excess NEM credits that were inadvertently omitted during that month.

Adjustment (9) – Unbilled Fuel Cost (Over)/Under-Recovery Adjustments

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As discussed for base fuel costs in Adjustment (4), the cycle billing process also affects the recovery of DERP avoided costs. The Company posted monthly adjustments throughout the actual review period and the estimated review period to account for timing differences.

Q. PLEASE EXPLAIN ORS AUDIT STAFF'S COMPUTATION OF THE CUMULATIVE (OVER)/UNDER-RECOVERY OF DISTRIBUTED ENERGY RESOURCE PROGRAM INCREMENTAL COSTS IN EXHIBIT GS-9.

A. ORS Audit Exhibit GS-9 provides details of ORS's calculation of the cumulative DERP incremental cost under-recovery balance of $798,037 through December 2017. ORS then added an estimated over-recovery of $167,876 for January 2018, estimated under-recoveries of $152,195 for February 2018, $391,134 for March 2018, and $697,793 for April 2018 to arrive at a cumulative under-recovery of $1,871,283 as of April 2018. Company witness Rooks' testimony (Exhibit No. ___ (AWR-8)) reports the under-recovery total through December 2017 as $798,039 and through April 2018, a cumulative under-recovery total of $1,871,285. Variances between ORS and the Company's ending balances for December 2017 and April 2018 are due to rounding.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS OR TRUE-UPS DURING EITHER THE ACTUAL OR THE ESTIMATED REVIEW PERIODS FOR THE DISTRIBUTED ENERGY RESOURCE INCREMENTAL COSTS COMPONENT?

A. Yes. The Company made the following adjustment as shown on Audit Exhibit GS-9:

Adjustment (10) – <u>Unbilled Fuel Cost (Over)/Under-Recovery Adjustments</u>

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As discussed for base fuel costs in Adjustment (4), the cycle billing process also affects the recovery of DERP incremental costs. The Company posted monthly adjustments throughout the actual review period to account for timing differences.

Q. WHAT IS THE RESULT OF ORS'S EXAMINATION?

A. Based on ORS's examination of the Company's books and records, and the Company's operations under the fuel cost recovery mechanism, ORS determined the Company's accounting practices are in compliance with S.C. Code Ann. § 58-27-865.

Based on ORS's examination, ORS agrees with the following (over)/under-recovery balances as stated by SCE&G:

- December 2017 fuel cost component under-recovery of $2,355,695;
- December 2017 environmental and avoided capacity cost component over-recovery balance of $2,272,425;
- December 2017 DERP avoided cost component over-recovery balance of $1,504,690;
- December 2017 DERP incremental cost component under-recovery balance of $798,039;
- April 2018 estimated fuel cost component over-recovery of $50,536,981;
- April 2018 estimated environmental and avoided capacity cost component over-recovery balance of $1,051,102;
- April 2018 estimated DERP avoided cost component over-recovery balance of $479,924;
- April 2018 estimated DERP incremental cost component under-recovery of $1,871,285.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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BY MS. PITTMAN:

Q Mr. Seaman-Huynh, will you please state your name and occupation?

A [SEAMAN-HUYNH] My name is Michael Seaman-Huynh. I'm a senior regulatory manager with the Office of Regulatory Staff.

Q Are you the same Michael Seaman-Huynh who prefiled nine pages of direct testimony in this case on March 23, 2018?

A [SEAMAN-HUYNH] Yes.

Q Do you have any changes or corrections to your testimony?

A [SEAMAN-HUYNH] No, I do not.

Q If I asked you the same questions today, would your answers be the same?

A [SEAMAN-HUYNH] Yes, they would.

MS. PITTMAN: Mr. Chairman, I'd ask that Mr. Seaman-Huynh's direct testimony be entered into the record as if given orally from the stand.

CHAIRMAN WHITFIELD: Mr. Seaman-Huynh's direct testimony will be entered in the record as if given orally from the stand.

MS. PITTMAN: Thank you.

BY MS. PITTMAN:

Q Mr. Seaman-Huynh, did you also prepare or cause to be prepared ten pages of exhibits labeled MSH-1 through

MSH-10, which were filed as attachments to your direct testimony?

A [SEAMAN-HUYNH] Yes.

Q Do you have any changes or corrections to your exhibits?

A [SEAMAN-HUYNH] No, I do not.

MS. PITTMAN: Mr. Chairman, I'd ask that the Exhibits MSH-1 through MSH-10 be marked for identification and entered as the the next composite hearing exhibit.

CHAIRMAN WHITFIELD: Mr. Seaman-Huynh's Exhibits MSH-1 through MSH-10 will be entered in as Hearing Exhibit No. 15.

[WHEREUPON, Hearing Exhibit No. 15 was marked and received in evidence.]

MS. PITTMAN: Thank you.

BY MS. PITTMAN:

Q Mr. Seaman-Huyn, did you prepare a summary of your direct testimony?

A [SEAMAN-HUYNH] Yes, I have.

Q Could you please present that to the Commission, at this time?

A [SEAMAN-HUYNH] Absolutely.

Good afternoon, Mr. Chairman, members of the Commission.

My testimony set forth ORS's findings and

recommendations resulting from our examination of SCE&G's fuel expenses and power plant operations used in the generation of electricity to meet its South Carolina retail customer requirements.

Numerous meetings were held with various personnel, representing a variety of areas, to discuss and review the company's fossil and nuclear fuel procurement; fuel transportation; environmental costs and compliance procedures; nuclear, fossil, and hydro-generation plant performance; plant dispatch; forecasting; and general company policies and procedures. ORS reviewed, among other materials, the company's monthly fuel reports, including power plant performance data, unit outages, generation statistics. Comparisons of actuals to estimates were evaluated for both megawatt-hour sales and fuel costs. ORS also analyzed SCE&G's fuel cost projections.

ORS reviewed the company's operation of its generating facilities and concluded that the company made reasonable efforts to maximize unit availability and minimize fuel costs. Additionally, ORS determined that SCE&G took appropriate corrective action with respect to plant outages that occurred during the review period.

With respect to forecasts, ORS reviewed forecasted

maintenance schedules for the company's major generation units, as well as the company's fuel price forecast. ORS also reviewed the company's load forecasting and ensuing dispatch procedures. Based on our review, ORS believes SCE&G's forecast is reasonable.

ORS has reviewed the company's proposal to apply gains from recently settled interest-rate swaps to reduce its base fuel components. The company's proposal is in compliance with Commission Order 2013-776 and ORS supports the company's proposal. ORS recommends the Commission approve the company's current base fuel component should remain in effect for the forecasted period. Additionally, ORS recommends the Commission approve the company's proposed environmental and avoided cost components and DERP avoided cost components for the forecasted period.

If approved by the Commission, the rates proposed would increase the average monthly bill of a residential customer on Rate 8, using 1000 kilowatt-hours, by approximately 72 cents.

This concludes my summary.

MS. PITTMAN: Thank you.

[PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED DIRECT TESTIMONY OF MICHAEL L. SEAMAN-HUYNH FOLLOWS AT PGS 879-888]

THE OFFICE OF REGULATORY STAFF

DIRECT TESTIMONY & EXHIBITS

OF

MICHAEL L. SEAMAN-HUYNH

MARCH 23, 2018

DOCKET NO. 2018-2-E

Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company

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DIRECT TESTIMONY AND EXHIBITS OF

MICHAEL L. SEAMAN-HUYNH

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-2-E

IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Michael Seaman-Huynh. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina 29201. I am employed by the State of South Carolina as a Senior Regulatory Manager in the Utility Rates and Services Division of the Office of Regulatory Staff ("ORS").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received my Bachelor's Degree from the University of South Carolina in 1997. Prior to my employment with ORS, I was employed as an energy analyst with a private consulting firm. I joined ORS in 2006 as an Electric Utilities Specialist and was promoted to Senior Electric Utilities Specialist in 2010. When the Energy Regulation Department was formed in August 2015, I assumed the position of Senior Regulatory Analyst. In May 2016, the Utility Rates and Services Division was formed, and I was promoted to the position of Senior Regulatory Manager.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

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A. Yes. I have testified on numerous occasions before the Commission in connection with hearings concerning fuel clauses, general rate cases, and Utility Facility Siting and Environmental Protection Act proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to set forth the ORS's recommendations resulting from our examination and review of South Carolina Electric & Gas Company's ("SCE&G" or "Company") fuel expenses and power plant operations used in the generation of electricity to meet the Company's retail customer requirements during the review period. The review period includes the actual data for January 2017 through December 2017 ("Actual Period"), estimated data for January 2018 through April 2018 ("Estimated Period"), and forecasted data for May 2018 through April 2019 ("Forecasted Period").

Q. WHAT DID YOUR REVIEW OF THE COMPANY'S FUEL EXPENSES AND PLANT OPERATIONS INVOLVE?

A. ORS examined various fuel and performance related documents as part of our review. These documents addressed the Company's electric generation and power plant outage and maintenance activities. In preparation for this proceeding, ORS analyzed the Company's monthly fuel reports including power plant performance data, unit outages and generation statistics. ORS examined the Company's contracts for nuclear fuel, coal, natural gas, fuel oil, transportation, and environmental reagents. ORS also evaluated the Company's policies and procedures for fuel procurement. All information was reviewed with reference to the Company's existing Adjustment for Fuel, Variable Environmental, Avoided Capacity, S.C. Code Ann. §58-27-865 (2015) (the "Fuel Clause Statute"), and the approved South Carolina Distributed Energy Resource Program ("DERP"). Additionally,

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ORS attended the March 28, 2017, Nuclear Regulatory Commission ("NRC") 2016 post-annual inspection meeting for the V.C. Summer Nuclear Station ("V.C. Summer").

Q. WHAT ADDITIONAL STEPS WERE TAKEN IN ORS'S REVIEW OF THE COMPANY'S PROPOSAL IN THIS PROCEEDING?

A. ORS met with Company personnel from various departments to discuss and review fossil and nuclear fuel procurement, fuel transportation, environmental compliance costs and procedures, emission allowances, generation plant performance, distributed energy resources, forecasting, and general Company policies and procedures pertaining to fuel procurement. These meetings occurred at ORS offices as well as SCE&G facilities in Cayce, SC. In addition, ORS monitors the nuclear, coal, natural gas, transportation and renewable industries through industry and governmental publications.

Q. DID ORS EXAMINE THE COMPANY'S PLANT OPERATIONS FOR THE ACTUAL PERIOD?

A. Yes. ORS reviewed the performance of the Company's generation units to determine if the Company made reasonable efforts to maximize unit availability and minimize fuel costs. ORS also reviewed the operating statistics of the Company's power plants by unit. Exhibit MSH-1 shows, in percentages, the annual availability, capacity, and forced outage factors of the Company's major generation units during the Actual Period. This exhibit also includes the North American Electric Reliability Corporation ("NERC") national five-year (2012-2016) averages for availability, capacity, and forced outage factors for each type of generation plant.

Q. PLEASE EXPLAIN HOW THE OUTAGES ARE REPRESENTED ON EXHIBITS MSH-2 THROUGH MSH-4.

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A. Exhibits MSH-2 and MSH-3 summarize outages lasting seven (7) or more days for major coal and natural gas units during the Actual Period, respectively. While not all plant outages were included in these exhibits, all outages were reviewed and found to be reasonable by ORS. Exhibit MSH-4 shows the duration, type and cause of each of the outages at V.C. Summer. During the Actual Period, there were four (4) separate outages, including one (1) scheduled refueling outage and three (3) forced outages. ORS reviewed each outage, including associated NRC documents, discussed these outages with Company management, and determined that the Company responded appropriately. V.C. Summer operated efficiently with an actual availability factor of 80.81% and an actual capacity factor of 81.70% during the Actual Period.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF THE COMPANY'S POWER PLANT OPERATIONS FOR THE ACTUAL PERIOD?

A. ORS's review of the Company's operation of its generation facilities during the Actual Period revealed that the Company made reasonable efforts to maximize unit availability and minimize fuel costs.

Q. DID ORS REVIEW THE COMPANY'S GENERATION MIX DURING THE ACTUAL PERIOD?

A. Yes. Exhibit MSH-5 shows the generation mix for the Actual Period by percentage and generation type. As shown in this exhibit, the nuclear, coal, and natural gas plants contributed an average of 18.99%, 34.72% and 33.14%, respectively, of the Company's generation throughout the Actual Period. This equates to approximately 86.85% of the Company's generation for the Actual Period. The remainder of the generation was met through a mix of hydroelectric, renewables, and purchased power.

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Q. DID ORS EXAMINE THE COMPANY'S FUEL COSTS ON A PLANT-BY-PLANT BASIS FOR THE ACTUAL PERIOD?

A. Yes. Exhibit MSH-6 shows the average fuel costs for the major generation plants on the Company's system for the Actual Period and the megawatt-hours ("MWh") produced by those plants. V.C. Summer generation statistics reflect SCE&G's 2/3 ownership of the plant. The chart shows the lowest average fuel cost of 0.956 cents/kilowatt-hour ("kWh") at V.C. Summer and the highest average fuel cost of 4.331 cents/kWh at McMeekin Station. The Company utilizes economic dispatch which generally requires that the lower cost units be dispatched first.

Q. DID ORS REVIEW THE COMPANY'S VARIABLE ENVIRONMENTAL COMPLIANCE RELATED COSTS?

A. Yes. ORS reviewed the Company's environmental compliance related costs including allowances for nitrogen oxide ("NO_X") and sulfur dioxide ("SO_2") emissions, reagents, and chemicals used in the reduction of these emissions. The use of these chemicals and reagents reduces the Company's NO_X and SO_2 emissions, and the costs associated with the use of these substances are included in the Company's Adjustment for Fuel and Variable Environmental Costs tariff as provided by the Fuel Clause Statute.

Q. HAS ORS REVIEWED THE ACCURACY OF THE COMPANY'S FORECAST?

A. Yes. As shown in Exhibit MSH-7, the Company's actual MWh sales were 0.97% lower than expected during the Actual Period. Exhibit MSH-8 shows that, on average, the actual fuel costs for the Actual Period were 6.20% lower than the projected monthly fuel costs.

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Q. WHAT CHANGES DOES THE COMPANY REQUEST TO ITS CURRENTLY APPROVED FACTORS?

A. Exhibit MSH-9 shows ending period balances of base fuel, environmental and avoided capacity costs, and DERP avoided costs beginning in January 2008. As of December 2017, the Company had a base fuel cumulative under-recovery balance of $2,355,695, a variable environmental and avoided capacity over-recovery balance of ($2,272,425), and DERP avoided costs over-recovery balance of ($1,504,687). As shown on ORS witness Smith's Exhibit GS-5, page 2 of 2, ORS projects the Company to have a base fuel cumulative over-recovery balance of ($50,536,981), a variable environmental and avoided capacity over-recovery balance of ($1,051,097), and DERP avoided costs over-recovery balance of ($479,920) as of April 30, 2018.

SCE&G requests that the Commission allow the Company to maintain the currently approved Base Fuel Component of 2.451 cents/kWh ("Base Fuel Component") for the Forecasted Period. As shown in Company witness EXHIBIT NO. __(AWR-10), this proposed Base Fuel Component is projected to give the Company an under-collected balance of $1,313,169 as of April 30, 2019. The Company has indicated through its testimony filed in this Docket that it is looking for ways to mitigate rate impacts to its retail electric customers.

The Company has requested to update its Variable Environmental and Avoided Capacity Cost Component ("Environmental and Avoided Capacity Component") and DERP Avoided Cost Component ("DERP Avoided Cost Component") to reflect the Company's forecasted expenses and allocation of these expenses to each class of customer based on its contribution to the Company's summer 2017 demand peak. The proposed

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Environmental and Avoided Capacity Components are projected to give the Company an over-collected balance of ($3,930) as of April 30, 2019. The proposed DERP Avoided Cost Components are projected to give the Company an over-collected balance of ($36,633) as of April 30, 2019.

Q. ARE THERE ANY ADDITIONAL FACTORS IN THIS DOCKET THAT WILL IMPACT CUSTOMERS' BILLS?

A. Yes. The Company has included proposed rates related to its DERP incremental expenses. As addressed by ORS witness Johnson, incremental expenses will be recovered as a fixed charge ("DERP Charge") on customers' bills.

Q. WHAT IS ORS'S POSITION CONCERNING THE COMPANY APPLYING THE GAINS FROM THE RECENT SETTLEMENT OF INTEREST RATE SWAPS TO OFFSET THE COMPANY'S FUEL COSTS?

A. ORS has reviewed the Company's proposal to apply gains from recently settled interest rate swaps to reduce its Base Fuel Component. The Company's proposal is in compliance with Commission Order No. 2013-776 and ORS supports the Company's proposal.

Q. DID THE COMPANY MAKE REDUCTIONS TO ITS ENVIRONMENTAL COMPONENTS DURING THE ACTUAL PERIOD PURSUANT TO COMMISSION ORDER NO. 2017-246?

A. No. In Docket No. 2016-373-E, SCE&G filed a petition to defer certain income tax and related costs arising from claims for deductions and credits the Company has made and will continue to make on its federal and state income tax returns. By Order No. 2016-820, the Commission approved the Company's request. In Docket No. 2017-2-E, SCE&G

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proposed to use the Internal Revenue Service ("IRS") Section 174 deduction claims to lower its Environmental Components based on its Accumulated Deferred Income Taxes ("ADIT") liability balances as of September 30, 2017. The Commission approved the Company's proposal in Commission Order No. 2017-246. In reviewing the Company's books and records in this Docket, ORS did not find the Company made any adjustments to its Environmental Capacity Components during the Actual Period attributed to the IRS Section 174 deduction claims.

Q. DOES ORS RECOMMEND ANY ADJUSTMENTS TO THE FUEL FACTORS PROPOSED BY THE COMPANY?

A. No. ORS recommends that the Commission approve the Company's current Base Fuel Component remain in effect for bills rendered on and after the first billing cycle for May 2018, and continue through the last billing cycle for April 2019. Additionally, ORS recommends that the Commission approve the Company's proposed Environmental and Avoided Capacity Components and DERP Avoided Cost Components for the period of May 2018 through April 2019.

Q. WHAT IMPACT WILL THE PROPOSED CHANGE HAVE ON THE TYPICAL AVERAGE MONTHLY BILL OF A RESIDENTIAL CUSTOMER?

A. Exhibit MSH-10 is a summary of the proposed fuel factor components for each customer class. If approved by the Commission, the rates proposed, including the ORS recommended DERP Charge addressed by ORS witness Johnson, would increase the average monthly bill for a Residential Customer on Rate 8 using 1,000 kWh from $147.53 to approximately $148.25, a net increase of $0.72 or 0.49%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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MS. PITTMAN: Mr. Chairman, this panel is available for questions.

CHAIRMAN WHITFIELD: Thank you, Ms. Pittman. I understand the parties are not going to cross; is that correct?

MR. WHITT: Yes, Mr. Chairman, that's correct.

CHAIRMAN WHITFIELD: Okay. That being the case, we'll go to Commissioner questions. Commissioners, questions for this panel. Commissioner Fleming.

EXAMINATION

BY COMMISSIONER FLEMING:

Q Good afternoon

A [SEAMAN-HUYNH] Good afternoon.

Q You talked about reviewing the forecasted fuel costs — or, the fuel costs presented. Have you reviewed the forecasted fuel costs?

A [SEAMAN-HUYNH] Yes, ma'am, we have.

Q And did you review their forecasting models and techniques?

A [SEAMAN-HUYNH] No, ma'am. We have not reviewed their forecasting models.

COMMISSIONER FLEMING: That's all. Thank you.

CHAIRMAN WHITFIELD: Thank you, Commissioner Fleming.

Any other Commissioner questions?

[No response]

EXAMINATION

BY CHAIRMAN WHITFIELD:

Q Well, if not, I have one for you, Mr. Seaman-Huynh. Do you believe it's appropriate to delay using the Section 174 tax benefits to offset the environmental component in this case, instead of considering them in conjunction with the company's and Dominion's Joint Petition that's coming up under Docket 2017-370-E?

A [SEAMAN-HUYNH] Yes, Commissioner, I believe that it is in the company's filing within that docket, and ORS will be reviewing the IRS 174 deductions as part of its review of that docket.

Q So you believe – ORS believes it's appropriate to review it in -370-E, in that upcoming Joint Petition?

A [SEAMAN-HUYNH] Yes, Commissioner, I do.

CHAIRMAN WHITFIELD: All right. Thank you.

I don't have anything further and I don't see any further Commissioner questions. Ms. Pittman, is there any redirect?

MS. PITTMAN: No redirect.

CHAIRMAN WHITFIELD: Okay. Well, you may step down, and thank you both for your testimony.

[WHEREUPON, the witnesses stood aside.]

At this time, while they're stepping down, I'll go to the parties and see if there are any final matters or closing statements – and Mr. Whitt, I'm going to come to you, first, since you asked – and everyone will have an opportunity, but I'm going to come to you first and let you make a – I think you said – a brief closing.

MR. WHITT: A very brief closing. First of all, Attorney Snowden and I appreciate the opportunity to appear in front of you and the other Commissioners, on behalf of the South Carolina Solar Business Alliance. We appreciate the opportunity.

And I would draw your attention to a document that was recently e-filed, a little over a week ago with this Commission, and ask, as was done earlier, to take judicial notice of this document. It's styled as SCE&G's Motion to Dismiss and Response in Opposition to Petition of CCL and SACE. And I will call your attention to the footnote that begins on page five and it goes over to page six on my written copy. And in the interest of fairness, I'll commend the entire footnote to you, to read, for the context of the entire footnote; however, I'll just read the part that's conclusory. But I

commend the entire footnote to you for your review, and I really believe we should follow the literal words, the literal words of this footnote.

"For the reasons set forth in the prefiled direct testimony of Dr. Lynch, however, SCE&G did not propose these avoided cost rates because the company believes that the previously approved methodology is no longer appropriate and that changes to the methodology are warranted and needed," end of quote.

And so we had a lot of puzzling questions with Attorney Ottenweller and Attorney Snowden with witnesses yesterday: Are we here for a change in methodology? And that's something that we had asserted early on. I would commend SCE&G's actual words to you for whether we're here, or not, for a change in methodology. And thank you, very much.

CHAIRMAN WHITFIELD: Thank you, Mr. Whitt.

Ms. Ottenweller.

MS. OTTENWELLER: I don't have a closing. I just have a couple of procedural items, but if other folks have closings, maybe it would be better to –

CHAIRMAN WHITFIELD: We're going to get back to some housekeeping matters here, at the end, so

let me see if there are any other – Mr. Elliot.

MR. ELLIOTT: No, thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: Mr. Bateman?

MR. BATEMAN: Thank you, Mr. Chairman. I have a very brief closing.

Mr. Chairman, members of the Commission, yesterday and this morning we heard testimony regarding some of the complexities in this case, as well as the relatively short timeframe each party had to draft and send discovery or respond to discovery, review data, review testimony, draft testimony, draft and file responsive testimony. With that being said, ORS was forced into the position it took as a result of SCE&G's failure to either respond to discovery requests, respond to discovery requests in a comprehensive manner, or respond to discovery requests timely.

Had these issues not arisen, the landscape of this hearing may have looked very different; however, these issues did arise. Because the company has failed to prove that the value of avoided capacity is actually zero, the company's position should be rejected.

With that, I'll end my closing and thank the Commission for their time. Thank you.

CHAIRMAN WHITFIELD: Thank you, Mr. Bateman. Mr. Burgess, or any attorneys representing the company.

MR. BURGESS: Thank you, Mr. Chairman, members of the Commission.

Like Mr. Whitt, on behalf of the SBA, on behalf of SCE&G we do appreciate this opportunity in which you've allowed the company to present its case with respect to the review of base fuel costs.

And I certainly want to make sure one very important element of this case doesn't escape this Commission; and that is, the fuel purchasing practices of SCE&G that were at issue in this case. There was no objection. There was no evidence put into the record disagreeing with any of SCE&G's fuel purchasing practices, its plant operations, its fuel inventory management. And for those reasons, the Commission should issue an order finding that SCE&G's fuel purchasing practices are reasonable and prudent.

Turning to the issue that has dominated this proceeding, which is avoided costs, it is clear through the testimony of Dr. Joe Lynch that the methodology that he has used is the same methodology that he has used in prior dockets. He

certainly indicated and stated to this Commission that there has been a change with respect to what has occurred in reality, over time, and those changes are that SCANA/SCE&G is no longer pursuing a nuclear power plant. That 865 megawatts – with the addition of 10 additional megawatts being signed, PPAs, this week – those are realities that Dr. Lynch cannot ignore when he is calculating avoided costs. And it is incumbent upon him to present this Commission with his best estimate on what he believes the avoided costs to be. And he was very clear with this Commission; he's been very clear with the other parties of record that it's his opinion – it's SCE&G's opinion – that the capacity component of the avoided cost calculation should be zero. Zero, for the incremental solar that is going to be put on SCE&G's system.

As I mentioned, there's 865 megawatts of purchased-power agreements that have been signed. Solar developers have put their names on the line, on those contracts, and have committed to build those projects, and we have no reason to believe that they won't do those. So you have to take this into consideration. The other parties of record, however, would and have decided that you should

ignore those changes. And it's our position that those changes should not be ignored, because it is incumbent upon this Commission, and we believe it's our responsibility to produce to you an avoided cost calculation that we believe to be accurate and credible – because at the end of the day, it's not SCE&G who pays the avoided costs; it's the customer who pays the avoided costs. And ORS, the Solar Business Alliance, they're arguing to you to increase the cost to customers as it relates to avoided capacity costs – to the avoided cost calculation. They want customers to pay higher expenses for these costs. That's what is the effect of their argument. I think it's important for this Commission to understand what their arguments mean to customers, because we can argue over the technicalities of how to calculate this – you should've added here, you should've subtracted here, you should've run this equation – but at the end of the day, it's going to land on somebody's bill, and that's the customer's bill. And it's their position that those costs should be higher.

I certainly understand the SBA's argument; they're in the business of building solar generation. And Commissioner Bockman hit the nail

on the head in questioning Dr. Lynch: Their goal, their objective, is to get that avoided cost as high as possible. That's their revenue stream. SCE&G does not begrudge them one bit for making that argument. Quite frankly, if I was in their position, I'd make the same argument. But at the end of the day, the company has to bring to this Commission what it believes to be the best calculation for avoided cost, and we have done that through the testimony of Joe Lynch.

So for those reasons, along with all the evidence of record, the company requests this Commission issue an order finding that the difference-in-revenue-requirements methodology, coupled with the 100-megawatt solar profile that Joe Lynch has included in his calculation, be found to be reasonable and prudent, and the avoided cost calculation that we have presented to this Commission be found to be reasonable and prudent.

Thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: Thank you, Mr. Burgess.

I'm going to ask our attorney to go over all the exhibits and all the items on his list in just a minute but, before I do, are there any other matters that need to be brought before the

Commission before we close? Ms. Ottenweller, I think you said you had a matter that you wanted to bring before us.

MS. OTTENWELLER: Mr. Chairman, just two quick matters. One is a correction. I had asked the Commission to take judicial notice of the 2013 IRP. I listed the wrong docket number. I said 2013-2-E; it should actually be 2013-9-E, and I would ask the Commission to take note of that.

CHAIRMAN WHITFIELD: Okay, so noted. 2013-9-E is the one you want us to take notice of.

MS. OTTENWELLER: Yes, sir.

CHAIRMAN WHITFIELD: Okay.

MS. OTTENWELLER: And then —

CHAIRMAN WHITFIELD: Was there something else?

MS. OTTENWELLER: Yes. My second request would just be that, in light of the issues presented, that we would have permission to file a legal brief, either in lieu of or in addition to proposed orders, if that's acceptable to the Commission?

CHAIRMAN WHITFIELD: I was going to give everyone an opportunity to provide proposed orders. I'll get to that in a minute, but, yes, you can also provide a legal brief.

MS. OTTENWELLER: Thank you, Mr. Chairman.

CHAIRMAN WHITFIELD: At this time, if there's nothing further from any of the parties, I'm going to turn it over to Mr. Stark to do a little housekeeping for us.

MR. STARK: Thank you, Mr. Chairman. I have a few housekeeping matters. First, let me remind the parties that those of you who had corrected testimony, please make sure that we receive copies of the corrected testimony so that others may have access to that.

Secondly, let me go through the hearing exhibit list and make sure that everybody has an accurate record. The first hearing exhibit is the prefiled exhibit of Henry Delk, HED-1. The second hearing exhibit is the exhibit from Michael Shinn, MDS-1. The third hearing exhibit is from Darrin Kahl, JDK-1. The fourth hearing exhibit is a composite exhibit from Allen Rooks, and that's Exhibits AWR-1 through -17. The fifth hearing exhibit is Joseph Lynch; it's a composite exhibit, JML-1 through JML-4. The sixth hearing exhibit is rebuttal – an exhibit in his rebuttal testimony, JML-5 through JML-7. That's also Joseph Lynch. The seventh hearing exhibit, I have a more

qualitative description, is Dr. Lynch's rebuttal testimony in Docket 2017-2-E.

The eighth hearing exhibit is a composite exhibit of all of Devi Glick's testimony – I'm sorry – Devi Glick's exhibits labeled DCG-1 through DCG-2, and her Surrebuttal Exhibits DCG-3 through DCG-4. That's all one composite exhibit in No. 8. The ninth hearing exhibit is SCE&G's 2018 IRP. The tenth hearing exhibit, I have captioned as CCL's Request and Response No. 2. The eleventh hearing exhibit is the prefiled exhibit from Sarah Johnson, SWJ-1. The twelfth hearing exhibit is the prefiled exhibit from Brian Horii, BKH[sic]-1. The thirteenth hearing exhibit is the surrebuttal exhibit from Brian Horii, labeled BHK[sic]-1. The fourteenth hearing exhibit is the prefiled exhibits – this is a composite exhibit – prefiled exhibit from Gaby Smith, labeled GS-1 through GS-9. The fifteenth hearing exhibit is the prefiled exhibits for Michael Seaman-Huynh, labeled MSH-1 through MSH-10. That is also a composite hearing exhibit.

Provided that all of that is correct, I have one more matter which is that of proposed order dates. From the communications between myself and the parties earlier, I found general consent to an

April 19th day for the proposed orders to be due. I assume that that's still acceptable for everyone.

[No response]

All right. And I have no further housekeeping matters, Mr. Chairman.

CHAIRMAN WHITFIELD: Thank you, Mr. Stark.

If nothing further and April 19th is an acceptable date for proposed orders, we'll have proposed orders due in by April 19th, and thank you to everyone for your participation over these last couple of days, and hearing adjourned.

[Witnesses excused.]

[WHEREUPON, at 3:35 p.m., the hearing in the above-entitled matter was adjourned.]

C E R T I F I C A T E

I, Jo Elizabeth M. Wheat, CVR-CM-GNSC, Notary Public in and for the State of South Carolina, do hereby certify that the foregoing is, to the best of my skill and ability, a true and correct transcript of proceedings had and testimony adduced in a hearing held in the above-captioned matter before the PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA;

That the witnesses appearing during said hearing were affirmed by me to state the truth, the whole truth, and nothing but the truth;

IN WITNESS WHEREOF, I have hereunto set my hand and seal, on this the 7th day of August, 2018.

Jo Elizabeth M. Wheat, CVR-CM/M-GNSC
Hearings Reporter, PSC/SC
My Commission Expires: January 27, 2021.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF BASE FUEL COSTS
JANUARY 2017 - APRIL 2018

		Actual							
		Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017
1. Fossil Fuel Costs		$ 33,387,825	$ 26,957,915	$ 26,674,248	$ 38,482,326	$ 41,284,243	$ 39,194,734	$ 42,228,616	$ 42,601,292
2. Nuclear Fuel Costs		$ 4,807,430	$ 4,342,125	$ 4,733,869	$ 1,006,734	$ -	$ 3,987,853	$ 4,466,748	$ 4,087,522
3. Fuel Costs in Purchased Power and Interchange Received		$ 14,228,443	$ 10,551,690	$ 13,712,124	$ 14,326,240	$ 21,233,432	$ 14,271,323	$ 16,775,168	$ 16,779,408
4 Less: Fuel Costs in Intersystem Sales		$ 471	$ 859	$ 369	$ 4,160	$ 77	$ 36,649	$ 9,127	$ 101
5. Total Fuel Costs (Lines 1+2+3-4)		$ 52,421,227	$ 41,850,881	$ 45,119,872	$ 53,811,140	$ 62,517,598	$ 57,417,261	$ 63,459,405	$ 63,468,121
6. Total System Sales Excluding Intersystem Sales (kWh)		1,901,337,747	1,600,031,452	1,698,485,415	1,614,992,596	1,878,095,181	2,122,686,180	2,201,844,920	2,311,829,540
7. Total Fuel Cost Per kWh Sales		$ 0.027571	$ 0.026156	$ 0.026585	$ 0.033320	$ 0.033288	$ 0.027049	$ 0.028820	$ 0.027454
8. Less Base Fuel Cost Per kWh Included in Rates		$ 0.02445	$ 0.02445	$ 0.02445	$ 0.02445	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451
9 Fuel Adjustment Per kWh		$ 0.00312	$ 0.00171	$ 0.00212	$ 0.00887	$ 0.00878	$ 0.00254	$ 0.00431	$ 0.00294
10. Retail kWh Sales		1,823,334,783	1,533,662,952	1,622,730,287	1,541,510,584	1,798,436,550	2,034,006,200	2,106,803,711	2,216,842,073
11. Over / Under Recovery Revenue		$ 5,868,805	$ 2,622,584	$ 3,440,188	$ 13,873,189	$ 15,790,273	$ 5,166,376	$ 9,080,324	$ 6,516,928
12. Carrying Costs [1]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13. Fixed Capacity Charges & Adjustments		$ (1,584,274)	$ (1,584,274)	$ (1,767,461)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)
14. Unbilled Fuel Cost Recovery Adjustment		$ 1,993,181	$ 1,973,209	$ (862,691)	$ (2,334,684)	$ (1,305,239)	$ 822,456	$ (3,512,465)	$ (145,308)
15. Net Over / Under Recovery Revenue		$ 6,097,712	$ 3,011,499	$ 710,036	$ 9,754,241	$ 12,900,760	$ 4,404,558	$ 3,983,585	$ 4,787,346
16. Cumulative (Over) Under Balance	$ (52,599,284)	$ (46,501,572)	$ (43,490,073)	$ (42,780,037)	$ (33,025,796)	$ (20,125,036)	$ (15,720,478)	$ (11,736,893)	$ (6,949,547)

	Actual				Forecast			
	Sep 2017	Oct 2017	Nov 2017	Dec 2017	Jan 2018	Feb 2018	Mar 2018	Apr 2018
17. Fossil Fuel Costs	$ 42,468,224	$ 34,554,778	$ 32,605,005	$ 41,572,354	$ 60,977,348	$ 34,560,000	$ 30,433,000	$ 27,776,000
18. Nuclear Fuel Costs	$ 3,310,947	$ 4,622,449	$ 4,064,788	$ 4,643,682	$ 4,643,411	$ 4,267,000	$ 4,727,000	$ 4,570,000
19. Fuel Costs in Purchased Power and Interchange Received	$ 8,073,707	$ 7,725,328	$ 6,829,627	$ 7,388,678	$ 45,127,272	$ 11,955,000	$ 10,925,000	$ 13,081,000
20. Less: Fuel Costs in Intersystem Sales	$ -	$ 261	$ 23,230	$ 3,094	$ 22,375	$ 97,000	$ 182,000	$ 91,000
21 Total Fuel Costs (Lines 1+2+3-4)	$ 53,852,878	$ 46,902,294	$ 43,476,190	$ 53,601,621	$ 110,725,656	$ 50,685,000	$ 45,903,000	$ 45,336,000
22. Total System Sales Excluding Intersystem Sales (kWh)	2,086,471,117	1,934,431,768	1,617,299,848	1,782,086,169	2,258,859,940	1,918,300,000	1,770,700,000	1,690,000,000
23. Total Fuel Cost Per kWh Sales	$ 0.025811	$ 0.024246	$ 0.026882	$ 0.030078	$ 0.049018	$ 0.026422	$ 0.025924	$ 0.026826
24. Less Base Fuel Cost Per kWh Included in Rates	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451
25. Fuel Adjustment Per kWh	$ 0.00130	$ (0.00026)	$ 0.00237	$ 0.00557	$ 0.02451	$ 0.00191	$ 0.00141	$ 0.00232
26. Retail kWh Sales	2,006,603,487	1,858,690,434	1,545,928,603	1,701,457,688	2,164,675,444	1,844,100,000	1,698,300,000	1,622,900,000
27. Over / Under Recovery Revenue	$ 2,608,585	$ (483,260)	$ 3,663,851	$ 9,477,119	$ 53,056,185	$ 3,522,231	$ 2,394,603	$ 3,765,128
28. Carrying Costs [1]	$ -	$ -	$ -	$ 5,143	$ 134,173	$ -	$ -	$ -
29. Fixed Capacity Charges & Adjustments [2]	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,172,890)	$ (115,323,546)	$ (1,584,274)	$ (1,584,274)
30. Unbilled Fuel Cost Recovery Adjustment	$ 3,230,700	$ 1,857,123	$ (1,808,724)	$ (2,908,199)	$ 592,492	$ 4,581,295	$ 884,202	$ (2,158,011)
31. Net Over / Under Recovery Revenue	$ 4,255,011	$ (210,411)	$ 270,853	$ 4,989,789	$ 52,609,970	$ (107,220,020)	$ 1,694,531	$ 22,843
32. Cumulative (Over) Under Balance	$ (2,694,536)	$ (2,904,947)	$ (2,634,094)	$ 2,355,695	$ 54,965,665	$ (52,254,355)	$ (50,559,824)	$ (50,536,981)

[1] Carrying Costs are calculated per the requirements of PSC Order No. 2017-246 using the effective 3-Year Treasury Note Rate plus 65 Basis Points.

[2] February 2018 adjustments include the application of $113,739,272 in interest rate swap gains to reduce the retail base fuel cost under-collection balance.

PENGAD 800-631-6989
EXHIBIT
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2018-2-E

EXHIBIT NO. ___ (AWR-1)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF BASE FUEL COSTS
MAY 2018 - APRIL 2019

		Forecast					
	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018
1. Fossil Fuel Costs	$ 34,197,000	$ 39,043,000	$ 41,480,000	$ 42,252,000	$ 33,343,000	$ 38,039,000
2. Nuclear Fuel Costs	$ 4,727,000	$ 4,472,000	$ 4,619,000	$ 4,701,000	$ 4,472,000	$ 763,000
3. Fuel Costs in Purchased Power and Interchange Received	$ 13,827,000	$ 16,204,000	$ 17,295,000	$ 17,405,000	$ 15,276,000	$ 14,638,000
4. Less: Fuel Costs in Intersystem Sales	$ 69,000	$ 93,000	$ 70,000	$ 46,000	$ 188,000	$ 71,000
5. Total Fuel Costs (Lines 1+2+3-4)	$ 52,682,000	$ 59,626,000	$ 63,324,000	$ 64,312,000	$ 52,905,000	$ 53,369,000
6. Total System Sales Excluding Intersystem Sales (kWh)	1,801,100,000	2,052,100,000	2,267,200,000	2,327,700,000	2,040,300,000	1,819,200,000
7. Total Fuel Cost Per kWh Sales	$ 0.029250	$ 0.028915	$ 0.027930	$ 0.027629	$ 0.025930	$ 0.029337
8 Less Base Fuel Cost Per kWh Included in Rates	$ 0.02457	$ 0.02457	$ 0.02457	$ 0.02457	$ 0.02457	$ 0.02457
9. Fuel Adjustment Per kWh	$ 0.00468	$ 0.00435	$ 0.00336	$ 0.00308	$ 0.00136	$ 0.00477
10. Retail kWh Sales	1,726,600,000	1,977,400,000	2,176,500,000	2,236,900,000	1,985,000,000	1,753,600,000
11. Over / Under Recovery Revenue	$ 8,080,488	$ 8,601,690	$ 7,313,040	$ 6,851,034	$ 2,672,400	$ 8,364,672
12. Carrying Costs	$ -	$ -	$ -	$ -	$ -	$ -
13. Fixed Capacity Charges & Adjustments	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)
14. Unbilled Fuel Cost Recovery Adjustment	$ (2,651,216)	$ (2,474,772)	$ (1,721,148)	$ 493,448	$ 4,018,124	$ 2,302,980
15. Net Over / Under Recovery Revenue	$ 3,844,998	$ 4,542,644	$ 4,007,618	$ 5,760,208	$ 5,106,250	$ 9,083,378
16. Cumulative (Over) Under Balance $ (50,536,981)	$ (46,691,983)	$ (42,149,339)	$ (38,141,721)	$ (32,381,513)	$ (27,275,263)	$ (18,191,885)

		Forecast					
	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019
17. Fossil Fuel Costs	$ 43,187,000	$ 38,060,000	$ 39,452,000	$ 32,842,000	$ 27,100,000	$ 28,828,000
18. Nuclear Fuel Costs	$ 1,037,000	$ 4,594,000	$ 4,594,000	$ 4,147,000	$ 4,594,000	$ 4,442,000
19. Fuel Costs in Purchased Power and Interchange Received	$ 10,051,000	$ 12,112,000	$ 12,416,000	$ 10,846,000	$ 11,439,000	$ 10,179,000
20. Less: Fuel Costs in Intersystem Sales	$ 98,000	$ 76,000	$ 75,000	$ 144,000	$ 176,000	$ 105,000
21. Total Fuel Costs (Lines 1+2+3-4)	$ 54,177,000	$ 54,690,000	$ 56,387,000	$ 47,691,000	$ 42,957,000	$ 41,344,000
22. Total System Sales Excluding Intersystem Sales (kWh)	1,629,300,000	1,648,400,000	2,059,000,000	1,926,200,000	1,771,400,000	1,687,200,000
23 Total Fuel Cost Per kWh Sales	$ 0.033252	$ 0.029588	$ 0.027386	$ 0.024759	$ 0.024250	$ 0.024505
24. Less Base Fuel Cost Per kWh Included in Rates	$ 0.02457	$ 0.02457	$ 0.02457	$ 0.02457	$ 0.02457	$ 0.02457
25. Fuel Adjustment Per kWh	$ 0.00868	$ 0.00502	$ 0.00282	$ 0.00019	$ (0 00032)	$ (0.00007)
26. Retail kWh Sales	1,560,300,000	1,770,400,000	1,955,300,000	1,634,500,000	1,679,600,000	1,601,300,000
27. Over / Under Recovery Revenue	$ 13,543,404	$ 8,887,408	$ 5,513,946	$ 348,555	$ (537,472)	$ (112,091)
28. Carrying Costs	$ -	$ -	$ -	$ -	$ -	$ -
29. Fixed Capacity Charges & Adjustments	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)
30. Unbilled Fuel Cost Recovery Adjustment	$ (3,087,910)	$ (2,021,378)	$ (1,048,828)	$ 5,072,959	$ 1,072,956	$ 44,785
31. Net Over / Under Recovery Revenue	$ 8,871,220	$ 5,281,756	$ 2,880,844	$ 3,837,240	$ (1,048,790)	$ (1,651,580)
32. Cumulative (Over) Under Balance	$ (9,320,665)	$ (4,038,909)	$ (1,158,065)	$ 2,679,175	$ 1,630,385	$ (21,195)

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EXHIBIT NO.___(AWR-1)

ROA 1534

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CALCULATION OF BASE FUEL COST COMPONENT
WITH ONE-YEAR RECOVERY PERIOD FOR BASE FUEL COST OVERCOLLECTION

1. Projected Data (May 2018 - April 2019)		
Cost of Fuel (000's)	$	643,464
System Sales (GWh)		23,239
Fuel Rate (Cents/kWh)		2.769
2. (Over)/Under Collection (000's) through April 2018	$	(50,537)
South Carolina Retail Sales (GWh)		22,239
(Over)/Under Collection Rate (Cents/kWh)		(0.227)
3. Base Fuel Cost Component (Cents/kWh)		
Projected Fuel Rate		2.769
Fixed Capacity Charges & Adjustments		(0.085)
Unbilled Fuel Cost Recovery Adjustment		-
Total Projected Fuel Rate		2.684
(Over)/Under Recovery Rate		(0.227)
Total Base Fuel Cost Component		**2.457**

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF DEMAND ALLOCATION FACTORS FOR VARIABLE ENVIRONMENTAL, AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE PROGRAM COSTS
JANUARY 2017 - APRIL 2019

Demand Allocation Factors

	Summer, 2016 Coincident Peak [1]		Summer, 2017 Coincident Peak [2]	
	KW	CP %	KW	CP %
1. Residential	2,074,049	46.75%	1,990,214	45.86%
2. Small General Service	780,929	17.60%	797,850	18.38%
3. Medium General Service	438,106	9.87%	427,159	9.84%
4. Large General Service	1,001,180	22.56%	987,111	22.75%
5. Wholesale	142,715	3.22%	137,523	3.17%
6. Total	4,436,979		4,339,857	

[1] - Used to allocate actual Variable Environmental, Avoided Capacity and Distributed Energy Resource Program Costs for the period January 2017 - December 2017.

[2] - Used to allocate projected Variable Environmental, Avoided Capacity, and Distributed Energy Resource Program Costs for the period January 2018 - April 2019.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF VARIABLE ENVIRONMENTAL AND AVOIDED CAPACITY COSTS
JANUARY 2017 - APRIL 2018

	Balance of Costs @ 12/31/2016	Actual												Forecast				Balance of Costs @ 4/30/2018
		Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017	Sep 2017	Oct 2017	Nov 2017	Dec 2017	Jan 2018	Feb 2018	Mar 2018	Apr 2018	
Variable Environmental Costs																		
1. SO2 Allowances		$ 995	$ 525	$ 305	$ 639	$ 349	$ 635	$ 727	$ 916	$ 737	$ 737	$ 530	$ 577	$ 666	$ 355	$ 316	$ 189	
2. NOx Allowances		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (389,176)	$ 15,507	$ -	$ -	$ -	$ -	$ -	
3. Lime		$ 563,149	$ 530,849	$ 470,955	$ 355,935	$ 560,692	$ 699,983	$ 690,709	$ 626,733	$ 566,024	$ 624,345	$ 357,390	$ 448,804	$ 553,306	$ 511,681	$ 462,476	$ 183,765	
4. Ammonia		$ 200,276	$ 204,803	$ 193,920	$ 325,622	$ 354,391	$ 270,482	$ 312,124	$ 168,070	$ 140,376	$ 135,023	$ 89,589	$ 150,116	$ 267,142	$ 210,948	$ 169,471	$ 213,086	
5. Other Reagents							$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
6. Environmental Costs Recovered in Interchem Sales		$ -	$ (81)	$ -	$ -	$ -	$ (1,564)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (160)	$ (160)	$ (160)	
7 Net Environmental Costs		$ 844,318	$ 709,315	$ 664,810	$ 682,314	$ 915,627	$ 969,532	$ 983,550	$ 797,721	$ 697,209	$ 374,929	$ 463,046	$ 600,686	$ 821,134	$ 731,822	$ 632,102	$ 396,480	
8. Avoided Capacity Costs		$ 21	$ 33	$ 16	$ -	$ -	$ 121	$ 447	$ 14,197	$ 33,018	$ 34,583	$ 32,306	$ 78,915	$ 224,597	$ 273,748	$ 359,810	$ 416,975	
Demand Allocations																		
9. Residential		46.75%	46.75%	46.75%	46.75%	46.75%	46.75%	46.75%	46.75%	46.75%	46.75%	46.75%	46.75%	45.65%	45.66%	45.67%	45.66%	
10. Small General Service		17.60%	17.60%	17.60%	17.60%	17.60%	17.60%	17.60%	17.60%	17.60%	17.60%	17.60%	17.60%	18.38%	18.38%	18.38%	18.38%	
11 Medium General Service		9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.84%	9.84%	9.84%	9.84%	
12. Large General Service		22.58%	22.58%	22.58%	22.58%	22.58%	22.58%	22.58%	22.58%	22.58%	22.58%	22.58%	22.58%	22.75%	22.75%	22.75%	22.75%	
Rate3 Environmental Cost Allocation																		
13. Residential		$ 394,719	$ 330,302	$ 292,749	$ 318,933	$ 428,009	$ 451,629	$ 458,506	$ 372,888	$ 325,945	$ 174,845	$ 222,440	$ 283,021	$ 376,572	$ 335,614	$ 292,654	$ 183,182	
14. Small General Service		$ 148,600	$ 124,311	$ 108,447	$ 120,070	$ 161,153	$ 170,022	$ 169,522	$ 140,331	$ 122,709	$ 65,824	$ 78,216	$ 105,721	$ 150,924	$ 134,509	$ 119,556	$ 73,421	
15. Medium General Service		$ 93,334	$ 69,713	$ 59,695	$ 67,335	$ 90,382	$ 95,347	$ 95,112	$ 78,725	$ 68,814	$ 36,914	$ 42,742	$ 59,288	$ 80,600	$ 72,011	$ 64,167	$ 39,307	
16. Large General Service		$ 180,478	$ 159,349	$ 136,445	$ 153,966	$ 209,549	$ 217,957	$ 217,389	$ 179,943	$ 157,200	$ 84,374	$ 97,886	$ 135,615	$ 186,006	$ 166,490	$ 149,352	$ 93,977	
17. Net Environmental Cost Allocation		$ 817,131	$ 683,671	$ 595,339	$ 660,248	$ 889,047	$ 934,929	$ 932,619	$ 771,887	$ 674,758	$ 361,957	$ 419,102	$ 581,345	$ 793,104	$ 708,624	$ 631,430	$ 389,707	
Retail Avoided Capacity Cost Allocation																		
18. Residential		$ 10	$ 15	$ 7	$ -	$ -	$ 56	$ 209	$ 6,637	$ 16,153	$ 16,158	$ 15,103	$ 36,472	$ 102,985	$ 125,539	$ 160,581	$ 190,788	
19 Small General Service		$ 4	$ 6	$ 3	$ -	$ -	$ 21	$ 79	$ 2,499	$ 6,649	$ 6,083	$ 5,688	$ 13,731	$ 41,276	$ 50,314	$ 64,479	$ 76,456	
20. Medium General Service		$ 2	$ 3	$ 2	$ -	$ -	$ 12	$ 44	$ 1,401	$ 3,841	$ 3,411	$ 3,109	$ 7,700	$ 22,697	$ 28,637	$ 34,520	$ 40,832	
21. Large General Service		$ 5	$ 7	$ 4	$ -	$ -	$ 22	$ 101	$ 3,233	$ 8,779	$ 7,767	$ 7,286	$ 17,600	$ 51,099	$ 62,777	$ 79,803	$ 94,534	
22. Net Avoided Capacity Cost Allocation		$ 21	$ 31	$ 16	$ -	$ -	$ 116	$ 433	$ 13,740	$ 37,662	$ 33,449	$ 31,286	$ 75,503	$ 217,447	$ 265,267	$ 339,669	$ 402,788	
Class Sales (in kWh)																		
23. Residential		697,228,431	622,074,893	525,452,377	467,731,209	581,272,527	739,701,534	819,508,045	658,372,200	722,011,594	628,853,797	471,784,760	607,173,952	608,600,000	720,300,000	580,000,000	488,600,000	
24 Small General Service		271,507,842	237,670,184	202,181,223	240,257,234	293,451,574	332,548,481	330,021,588	257,948,788	328,939,858	304,210,494	248,114,548	257,543,049	288,300,000	295,600,000	262,500,000	254,000,000	
25. Medium General Service		179,305,469	158,602,609	160,104,723	164,380,859	152,492,313	211,432,703	203,637,301	220,492,009	205,022,201	180,001,294	163,078,843	160,033,630	181,000,000	185,000,000	163,100,000	174,600,000	
26 Large General Service		600,605,576	522,314,532	551,418,382	643,992,107	709,559,576	725,542,001	727,013,068	755,207,111	712,002,640	714,091,562	640,343,737	648,004,629	627,000,000	633,500,000	559,400,000	552,500,000	
Environmental Factors (per kWh)																		
27 Residential		$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	
28. Small General Service		$ 0.00005	$ 0.00005	$ 0.00005	$ 0.00005	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	
29. Medium General Service		$ 0.00004	$ 0.00004	$ 0.00004	$ 0.00004	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	$ 0.00033	
30. Large General Service		$ 0.00017	$ 0.00017	$ 0.00017	$ 0.00017	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	$ 0.00020	
Env. & Avoided Cap. Cost Revenue Recovered																		
31. Residential		$ 218,912	$ 187,094	$ 168,129	$ 148,674	$ 273,197	$ 347,697	$ 384,745	$ 403,435	$ 344,048	$ 294,198	$ 221,739	$ 285,372	$ 378,932	$ 344,051	$ 272,892	$ 228,702	
32. Small General Service		$ 78,508	$ 61,784	$ 53,567	$ 52,610	$ 114,459	$ 129,604	$ 139,709	$ 139,599	$ 120,675	$ 118,042	$ 95,885	$ 100,442	$ 116,337	$ 111,394	$ 101,585	$ 89,060	
33. Medium General Service		$ 43,033	$ 37,978	$ 40,585	$ 39,453	$ 93,822	$ 89,788	$ 67,660	$ 72,760	$ 69,647	$ 62,399	$ 53,815	$ 64,991	$ 59,730	$ 55,044	$ 53,823	$ 57,684	
34 Large General Service		$ 112,303	$ 100,672	$ 119,741	$ 104,479	$ 141,312	$ 143,106	$ 145,563	$ 151,241	$ 142,491	$ 142,979	$ 128,099	$ 129,213	$ 133,582	$ 120,780	$ 123,880	$ 135,550	
35. Total Environmental Revenue		$ 445,856	$ 387,529	$ 382,022	$ 351,216	$ 682,491	$ 622,292	$ 720,699	$ 769,894	$ 653,709	$ 618,206	$ 499,538	$ 580,018	$ 688,290	$ 637,770	$ 552,180	$ 521,846	
Env. Avoid Cap. & Unified Fuel Cost Adjustments																		
36. Residential		$ 11,656	$ 11,112	$ (5,617)	$ (60,734)	$ (11,676)	$ 9,973	$ (32,735)	$ (486)	$ 29,930	$ 15,652	$ (15,366)	$ (28,629)	$ 6,707	$ 44,813	$ 8,758	$ (89,014)	
37. Small General Service		$ 3,733	$ 4,110	$ (2,349)	$ (21,222)	$ (4,552)	$ 2,227	$ (10,957)	$ (174)	$ 11,195	$ 6,312	$ (6,656)	$ (9,441)	$ 1,775	$ 14,318	$ 3,260	$ (42,883)	
38. Medium General Service		$ 2,295	$ 2,504	$ (1,353)	$ (13,375)	$ (2,716)	$ 1,195	$ (5,779)	$ (94)	$ 5,599	$ 3,316	$ (3,736)	$ (5,153)	$ 910	$ 7,072	$ 1,734	$ (34,976)	
39. Large General Service		$ 5,952	$ 6,690	$ (3,529)	$ (27,114)	$ (6,052)	$ 2,479	$ (12,329)	$ (207)	$ 12,374	$ 7,595	$ (8,866)	$ (12,157)	$ 2,078	$ 16,374	$ 4,286	$ (58,104)	
40. Net Environmental Cost Adjustments		$ 23,636	$ 24,416	$ (12,944)	$ (122,445)	$ (25,340)	$ 15,874	$ (61,853)	$ (988)	$ 59,465	$ 32,875	$ (34,670)	$ (53,571)	$ 10,513	$ 81,577	$ 18,029	$ (225,978)	
Environmental (Over)/Under Recovery																		
41 Residential	$ (1,804,535)	$ 186,519	$ 174,265	$ 153,910	$ 118,527	$ 143,134	$ 150,932	$ 33,242	$ (24,428)	$ 30,023	$ (67,543)	$ (19,578)	$ 5,101	$ 106,723	$ 160,815	$ 125,812	$ 49,242	$ (570,402)
42. Small General Service	$ (734,288)	$ 61,749	$ 68,633	$ 33,838	$ 36,238	$ 41,761	$ 42,576	$ 30,023	$ 3,167	$ 12,076	$ (40,423)	$ (20,742)	$ 9,559	$ 77,040	$ 87,757	$ 80,000	$ 7,932	$ (173,724)
43. Medium General Service	$ (433,444)	$ 43,588	$ 34,842	$ 17,758	$ 14,587	$ 24,122	$ 20,782	$ 21,820	$ 7,273	$ 9,878	$ (18,749)	$ (11,820)	$ 7,044	$ 44,077	$ 50,978	$ 49,888	$ (2,430)	$ (119,499)
44. Large General Service	$ (973,172)	$ 84,143	$ 65,349	$ 22,179	$ 7,318	$ 59,179	$ 75,334	$ 59,516	$ 31,993	$ 30,042	$ (49,210)	$ (31,987)	$ 11,745	$ 100,365	$ 118,341	$ 80,602	$ (19,003)	$ (192,477)
45. Total (Over)/Under Recovery		$ 394,892	$ 340,789	$ 107,388	$ 176,587	$ 268,226	$ 254,624	$ 144,893	$ 17,575	$ 89,177	$ (193,925)	$ (33,910)	$ 33,459	$ 334,205	$ 417,853	$ 426,568	$ 41,681	$ (1,051,102)
46 Cumulative (Over)/Under Recovery	$ (3,004,539)	$ (3,509,947)	$ (3,169,158)	$ (3,061,772)	$ (2,885,185)	$ (2,636,959)	$ (2,382,336)	$ (2,238,033)	$ (2,120,157)	$ (2,032,980)	$ (2,221,905)	$ (2,308,834)	$ (2,272,425)	$ (1,937,820)	$ (1,519,731)	$ (1,092,763)	$ (1,051,102)	

EXHIBIT NO.___ (AWR-4)

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF VARIABLE ENVIRONMENTAL AND AVOIDED CAPACITY COSTS
MAY 2018 - APRIL 2019

	Balance of Costs @ 4/30/2018	Forecast May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	Balance of Costs @ 4/30/2019
Variable Environmental Costs														
1. SO2 Allowances		$ 283	$ 441	$ 431	$ 435	$ 349	$ 140	$ 419	$ 384	$ 330	$ 340	$ 266	$ 239	
2. NOx Allowances		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3. Lime		$ 692,040	$ 637,783	$ 587,554	$ 549,929	$ 410,772	$ 666,273	$ 426,618	$ 557,290	$ 561,593	$ 533,134	$ 446,389	$ 219,281	
4. Ammonia		$ 273,219	$ 259,689	$ 290,563	$ 166,106	$ 213,447	$ 279,830	$ 242,466	$ 209,502	$ 244,139	$ 200,509	$ 163,155	$ 223,533	
5 Environmental Costs Recovered in Intersystem Sales		$ (180)	$ (230)	$ (280)	$ (260)	$ (160)	$ (70)	$ (70)	$ (90)	$ (90)	$ (140)	$ (140)	$ (140)	
6. Net Environmental Costs		$ 965,362	$ 897,674	$ 878,268	$ 716,190	$ 624,408	$ 945,173	$ 669,433	$ 766,686	$ 805,972	$ 733,843	$ 611,670	$ 443,013	
7. Net Avoided Cost Capacity Credits		$ 392,241	$ 1,080,740	$ 1,135,277	$ 1,075,374	$ 327,492	$ 309,379	$ 253,999	$ 252,972	$ 274,987	$ 338,508	$ 379,496	$ 449,990	
Demand Allocators														
8. Residential		45.66%	45.66%	45.66%	45.66%	45.66%	45.66%	45.66%	45.66%	45.66%	45.66%	45.66%	45.66%	
9. Small General Service		18.38%	18.38%	18.38%	18.38%	18.38%	18.38%	18.38%	18.38%	18.38%	18.38%	18.38%	18.38%	
10 Medium General Service		9.84%	9.84%	9.84%	9.84%	9.84%	9.84%	9.84%	9.84%	9.84%	9.84%	9.84%	9.84%	
11. Large General Service		22.75%	22.75%	22.75%	22.75%	22.75%	22.75%	22.75%	22.75%	22.75%	22.75%	22.75%	22.75%	
Retail Environmental Cost Allocation														
12. Residential		$ 442,715	$ 411,873	$ 402,763	$ 328,445	$ 288,354	$ 433,456	$ 307,002	$ 351,327	$ 369,619	$ 339,292	$ 280,512	$ 203,169	
13. Small General Service		$ 177,434	$ 164,992	$ 161,429	$ 131,639	$ 114,788	$ 173,723	$ 123,042	$ 140,807	$ 148,138	$ 135,983	$ 112,425	$ 81,426	
14. Medium General Service		$ 94,992	$ 88,331	$ 86,424	$ 70,473	$ 61,442	$ 93,005	$ 65,872	$ 75,383	$ 79,308	$ 72,801	$ 60,188	$ 43,592	
15. Large General Service		$ 219,620	$ 204,221	$ 199,811	$ 162,933	$ 142,053	$ 215,027	$ 152,298	$ 174,285	$ 183,359	$ 168,314	$ 139,155	$ 100,785	
16. Net Environmental Cost Allocation		$ 934,761	$ 869,217	$ 850,447	$ 693,487	$ 604,615	$ 915,211	$ 648,212	$ 741,802	$ 780,424	$ 716,390	$ 592,280	$ 428,969	
Retail Avoided Capacity Cost Allocation														
17. Residential		$ 179,592	$ 495,627	$ 520,636	$ 493,167	$ 150,188	$ 141,831	$ 116,484	$ 116,013	$ 126,109	$ 155,240	$ 174,037	$ 206,365	
18. Small General Service		$ 72,094	$ 198,640	$ 208,664	$ 197,654	$ 60,193	$ 56,854	$ 46,685	$ 46,496	$ 50,543	$ 62,218	$ 69,751	$ 82,706	
19. Medium General Service		$ 38,597	$ 106,345	$ 111,711	$ 105,817	$ 32,225	$ 30,443	$ 24,994	$ 24,892	$ 27,059	$ 33,309	$ 37,342	$ 44,279	
20. Large General Service		$ 89,295	$ 245,868	$ 258,276	$ 244,848	$ 74,504	$ 70,394	$ 57,785	$ 57,551	$ 62,560	$ 77,011	$ 86,335	$ 102,373	
21. Net Avoided Capacity Cost Allocation		$ 379,608	$ 1,046,480	$ 1,099,289	$ 1,041,286	$ 317,110	$ 299,572	$ 245,948	$ 244,952	$ 266,271	$ 327,778	$ 367,465	$ 435,725	
Allocation of Avoided Cap. & Unbilled Fuel Cost Adj.														
22. Residential		$ (37,025)	$ (34,812)	$ (23,484)	$ 7,441	$ 55,854	$ 31,517	$ (43,271)	$ (28,746)	$ (14,111)	$ 69,792	$ 15,799	$ 649	
23 Small General Service		$ (14,838)	$ (13,952)	$ (9,412)	$ 2,983	$ 22,386	$ 12,631	$ (17,342)	$ (11,521)	$ (5,656)	$ 27,972	$ 6,332	$ 261	
24. Medium General Service		$ (7,947)	$ (7,472)	$ (5,042)	$ 1,594	$ 11,982	$ 6,759	$ (9,287)	$ (6,171)	$ (3,031)	$ 14,972	$ 3,387	$ 136	
25. Large General Service		$ (18,378)	$ (17,281)	$ (11,662)	$ 3,680	$ 27,696	$ 15,623	$ (21,477)	$ (14,272)	$ (7,012)	$ 34,611	$ 7,828	$ 311	
26. Unbilled Fuel Adjustment		$ (78,168)	$ (73,517)	$ (49,600)	$ 15,698	$ 117,918	$ 66,530	$ (91,377)	$ (60,710)	$ (29,810)	$ 147,347	$ 33,344	$ 1,357	
Total Env. & Avoided Costs by Class														
27. Residential	$ (376,402)	$ 585,572	$ 872,488	$ 899,937	$ 829,053	$ 492,396	$ 606,854	$ 380,215	$ 438,594	$ 481,617	$ 564,324	$ 470,348	$ 410,180	$ 6,455,176
28. Small General Service	$ (173,724)	$ 234,690	$ 349,680	$ 360,681	$ 332,273	$ 197,345	$ 243,216	$ 152,385	$ 175,782	$ 193,025	$ 226,173	$ 188,508	$ 164,395	$ 2,644,431
29. Medium General Service	$ (116,499)	$ 125,842	$ 187,204	$ 193,093	$ 177,884	$ 105,649	$ 130,207	$ 81,578	$ 94,104	$ 103,336	$ 121,082	$ 100,917	$ 88,007	$ 1,390,205
30. Large General Service	$ (192,477)	$ 290,477	$ 432,868	$ 446,425	$ 411,201	$ 244,253	$ 301,034	$ 188,604	$ 217,884	$ 238,907	$ 279,936	$ 233,316	$ 203,469	$ 3,305,577
31. Total Environ. & Avoided Cap. Costs	$ (1,051,102)	$ 1,236,581	$ 1,842,180	$ 1,900,136	$ 1,750,471	$ 1,039,643	$ 1,281,313	$ 802,783	$ 926,044	$ 1,016,885	$ 1,191,515	$ 993,089	$ 866,051	$ 13,795,389
Class Sales (in kWh)														
32. Residential		525,500,000	690,500,000	827,200,000	853,000,000	674,800,000	532,600,000	456,800,000	643,000,000	799,500,000	736,700,000	583,600,000	488,300,000	7,811,700,000
33. Small General Service		281,500,000	319,200,000	344,900,000	364,000,000	326,600,000	292,700,000	242,100,000	281,600,000	299,800,000	290,300,000	264,400,000	257,400,000	3,544,700,000
34. Medium General Service		183,200,000	199,700,000	211,300,000	220,300,000	198,100,000	187,100,000	161,700,000	165,400,000	178,600,000	169,400,000	163,900,000	179,100,000	2,209,900,000
35. Large General Service		711,200,000	742,900,000	788,800,000	776,900,000	740,900,000	718,300,000	674,900,000	676,300,000	652,700,000	615,800,000	643,700,000	655,000,000	8,371,400,000
Environmental Factors (per kWh)														
36. Residential		$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083	$ 0.00083
37. Small General Service		$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075	$ 0.00075
38. Medium General Service		$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063	$ 0.00063
39. Large General Service		$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039	$ 0.00039
Environmental Revenue Recovered														
40. Residential		$ 438,165	$ 573,115	$ 668,576	$ 707,900	$ 560,084	$ 442,224	$ 379,144	$ 533,680	$ 663,565	$ 611,481	$ 484,388	$ 405,289	
41. Small General Service		$ 211,125	$ 239,400	$ 258,675	$ 273,000	$ 244,950	$ 219,525	$ 181,575	$ 196,350	$ 224,850	$ 217,725	$ 198,300	$ 193,050	
42. Medium General Service		$ 115,416	$ 125,811	$ 133,119	$ 138,789	$ 124,803	$ 117,873	$ 101,871	$ 104,202	$ 112,518	$ 106,732	$ 102,600	$ 110,313	
43. Large General Service		$ 277,368	$ 289,731	$ 299,052	$ 302,991	$ 288,951	$ 276,867	$ 263,211	$ 263,367	$ 254,553	$ 240,182	$ 251,043	$ 255,450	
44. Total Environmental Revenue		$ 1,040,074	$ 1,228,057	$ 1,377,422	$ 1,422,770	$ 1,218,788	$ 1,056,589	$ 925,801	$ 1,097,599	$ 1,255,506	$ 1,174,160	$ 1,036,421	$ 964,102	
Environmental (Over)/Under Recovery														
45. Residential	$ (376,402)	$ 149,407	$ 299,373	$ 213,361	$ 121,053	$ (67,688)	$ 164,630	$ 1,071	$ (95,086)	$ (181,968)	$ (47,157)	$ (14,040)	$ 4,891	$ (28,535)
46. Small General Service	$ (173,724)	$ 23,565	$ 110,280	$ 102,006	$ 59,273	$ (47,605)	$ 23,693	$ (29,190)	$ (20,568)	$ (31,825)	$ 8,448	$ (9,792)	$ (28,655)	$ (14,094)
47. Medium General Service	$ (116,499)	$ 10,226	$ 61,393	$ 59,974	$ 39,085	$ (19,154)	$ 12,334	$ (20,292)	$ (10,098)	$ (9,182)	$ 16,250	$ (1,773)	$ (22,305)	$ (2,032)
48. Large General Service	$ (192,477)	$ 13,109	$ 143,077	$ 147,373	$ 108,270	$ (44,698)	$ 22,067	$ (74,607)	$ (45,803)	$ (15,645)	$ 39,774	$ (17,727)	$ (51,981)	$ 40,731
49. Total (Over)/Under Recovery		$ 195,307	$ 614,123	$ 522,714	$ 327,701	$ (179,145)	$ 222,724	$ (123,018)	$ (171,585)	$ (238,621)	$ 17,335	$ (43,332)	$ (98,051)	$ (3,930)
50. Cumulative (Over)/Under Recovery	$ (1,051,102)	$ (854,795)	$ (240,672)	$ 282,042	$ 609,743	$ 430,598	$ 653,322	$ 530,304	$ 358,739	$ 120,116	$ 137,453	$ 94,121	$ (3,930)	

EXHIBIT NO. ____ (AWR-5)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF DISTRIBUTED ENERGY RESOURCE PROGRAM AVOIDED COSTS
JANUARY 2017 - APRIL 2018

	Balance of Costs @ 12/31/2016	Actual Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017	Sep 2017	Oct 2017	Nov 2017	Dec 2017	Forecast Jan 2018	Feb 2018	Mar 2018	Apr 2018	Balance of Costs @ 4/30/2018
DERP Avoided Costs																		
1. SCA Avoided Costs		$ 10,507	$ 13,111	$ 21,370	$ 24,456	$ 34,814	$ 49,330	$ 48,520	$ 56,324	$ 50,489	$ 50,631	$ 44,521	$ 38,480	$ 42,034	$ 55,834	$ 84,270	$ 121,583	
2. Utility Scale Avoided Costs		$ 39,577	$ 51,944	$ 59,325	$ 63,177	$ 114,684	$ 199,694	$ 249,764	$ 309,237	$ 322,727	$ 288,575	$ 199,625	$ 219,326	$ 303,855	$ 370,397	$ 437,978	$ 519,335	
3. Community Solar Avoided Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
4. Excess NEM Avoided Cost Payments		$ -	$ 65	$ 109	$ 176	$ -	$ 289	$ -	$ 152	$ 116	$ 555	$ 67,469	$ 0	$ 51	$ -	$ -	$ -	
5. Total DERP Avoided Costs		$ 50,173	$ 65,143	$ 80,803	$ 87,808	$ 149,498	$ 249,604	$ 298,284	$ 364,713	$ 373,332	$ 339,761	$ 311,636	$ 257,817	$ 345,940	$ 426,230	$ 522,257	$ 640,918	
Demand Allocators																		
6. Residential		48.30%	48.30%	48.30%	48.30%	48.30%	48.30%	48.30%	48.30%	48.30%	48.30%	48.30%	48.30%	47.36%	47.36%	47.36%	47.36%	
7. Small General Service		18.19%	18.19%	18.19%	18.19%	18.19%	18.19%	18.19%	18.19%	18.19%	18.19%	18.19%	18.19%	18.99%	18.99%	18.99%	18.99%	
8. Medium General Service		10.20%	10.20%	10.20%	10.20%	10.20%	10.20%	10.20%	10.20%	10.20%	10.20%	10.20%	10.20%	10.16%	10.16%	10.16%	10.16%	
9. Large General Service		23.31%	23.31%	23.31%	23.31%	23.31%	23.31%	23.31%	23.31%	23.31%	23.31%	23.31%	23.31%	23.49%	23.49%	23.49%	23.49%	
DERP Avoided Cost Allocation																		
10. Residential		$ 24,233	$ 31,457	$ 39,026	$ 42,412	$ 72,207	$ 110,211	$ 143,105	$ 176,150	$ 180,319	$ 164,104	$ 150,617	$ 124,526	$ 163,837	$ 201,892	$ 247,341	$ 303,526	
11. Small General Service		$ 9,127	$ 11,851	$ 14,688	$ 15,972	$ 27,184	$ 43,768	$ 53,894	$ 66,341	$ 67,909	$ 61,893	$ 56,723	$ 46,697	$ 63,034	$ 80,041	$ 99,177	$ 121,710	
12. Medium General Service		$ 5,118	$ 6,645	$ 8,242	$ 8,956	$ 15,249	$ 24,542	$ 30,221	$ 37,201	$ 38,069	$ 34,698	$ 31,807	$ 26,297	$ 35,148	$ 43,305	$ 53,091	$ 66,117	
13. Large General Service		$ 11,695	$ 15,189	$ 19,838	$ 20,488	$ 34,848	$ 56,085	$ 69,064	$ 85,015	$ 87,094	$ 79,193	$ 72,589	$ 60,997	$ 81,261	$ 100,122	$ 122,676	$ 150,532	
14. Net Environmental Cost Allocation		$ 50,173	$ 65,143	$ 80,803	$ 87,808	$ 149,498	$ 240,604	$ 296,284	$ 364,713	$ 373,332	$ 339,781	$ 311,636	$ 257,817	$ 345,940	$ 426,230	$ 522,257	$ 640,918	
Class Sales (in kWh)																		
15. Residential		687,228,491	522,074,693	525,402,377	467,731,306	581,270,627	729,781,634	818,608,045	858,372,390	732,011,504	635,953,797	471,784,760	607,173,952	605,600,000	733,300,000	560,600,000	428,600,000	
16. Small General Service		271,597,642	237,070,184	252,181,222	240,607,694	253,451,574	332,543,461	330,031,566	357,045,760	329,936,956	304,210,484	248,114,543	257,543,049	288,300,000	285,600,000	260,500,000	264,000,000	
17. Medium General Service		170,305,459	156,922,605	162,104,723	164,358,658	162,492,313	211,492,103	205,037,301	220,462,203	208,022,201	192,051,234	153,976,643	166,833,838	161,800,000	166,800,000	163,100,000	174,600,000	
18. Large General Service		669,606,576	592,314,532	651,418,282	643,892,107	706,559,676	725,542,691	727,013,980	755,207,111	712,602,040	714,601,562	640,343,737	648,064,629	667,800,000	633,500,000	669,400,000	692,500,000	
DERP Avoided Rates (per kWh)																		
19. Residential		$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	$ 0.00015	
20. Small General Service		$ 0.00012	$ 0.00012	$ 0.00012	$ 0.00012	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	
21. Medium General Service		$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00011	
22. Large General Service		$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	$ 0.00007	
DERP Avoided Cost Revenue Recovered																		
23 Residential		$ 103,084	$ 78,311	$ 78,810	$ 70,160	$ 87,191	$ 110,967	$ 122,791	$ 128,756	$ 109,802	$ 93,593	$ 70,768	$ 91,076	$ 120,540	$ 109,995	$ 97,090	$ 72,990	
24 Small General Service		$ 32,568	$ 28,820	$ 30,252	$ 28,697	$ 33,130	$ 43,231	$ 42,003	$ 46,533	$ 42,892	$ 39,547	$ 31,995	$ 33,481	$ 38,778	$ 37,128	$ 33,865	$ 33,020	
25. Medium General Service		$ 19,734	$ 17,388	$ 18,802	$ 18,063	$ 21,174	$ 23,264	$ 22,529	$ 24,253	$ 22,882	$ 20,767	$ 17,029	$ 18,294	$ 19,910	$ 18,348	$ 17,941	$ 19,226	
26 Large General Service		$ 45,242	$ 41,492	$ 45,569	$ 45,079	$ 49,489	$ 50,768	$ 50,954	$ 52,684	$ 49,840	$ 50,042	$ 44,924	$ 45,225	$ 48,746	$ 44,345	$ 40,658	$ 47,775	
27. Total Environmental Revenue		$ 201,638	$ 165,592	$ 173,273	$ 162,219	$ 195,974	$ 228,250	$ 238,268	$ 252,406	$ 225,416	$ 204,270	$ 165,525	$ 188,046	$ 226,275	$ 209,816	$ 185,754	$ 173,013	
DERP Avoided & Unbilled Fuel Cost Adjustments																		
28. Residential		$ 5,553	$ 5,500	$ 2,315	$ (7,079)	$ (3,560)	$ 1,982	$ (10,315)	$ (54)	$ 9,340	$ 4,918	$ (4,723)	$ (8,344)	$ 1,834	$ 13,039	$ 2,071	$ (53,889)	
29. Small General Service		$ 1,790	$ 2,003	$ 800	$ (2,918)	$ (1,586)	$ 778	$ (3,604)	$ (29)	$ 3,648	$ 2,072	$ (2,135)	$ (3,097)	$ 589	$ 4,705	$ 1,039	$ (28,963)	
30. Medium General Service		$ 1,084	$ 1,213	$ 460	$ (1,824)	$ (952)	$ 418	$ (1,900)	$ (13)	$ 1,948	$ 1,060	$ (1,197)	$ (1,673)	$ 302	$ 2,325	$ 651	$ (16,831)	
31. Large General Service		$ 2,649	$ 2,918	$ 1,001	$ (4,549)	$ (2,030)	$ 908	$ (4,280)	$ (28)	$ 4,229	$ 2,692	$ (2,931)	$ (4,143)	$ 719	$ 5,619	$ 1,438	$ (41,819)	
32. Net Environmental Cost Adjustments		$ 11,077	$ 11,628	$ 4,672	$ (16,367)	$ (8,045)	$ 4,079	$ (20,099)	$ (151)	$ 19,173	$ 10,702	$ (11,048)	$ (17,227)	$ 3,435	$ 25,687	$ 5,699	$ (151,442)	
DERP Avoided (Over)/Under Recovery																		
33. Residential	$ (835,958)	$ (73,188)	$ (41,344)	$ (37,487)	$ (34,827)	$ (18,564)	$ 7,226	$ 9,999	$ 47,316	$ 78,657	$ 75,129	$ 75,120	$ 25,100	$ 44,531	$ 105,905	$ 192,922	$ 168,969	$ (241,271)
34. Small General Service	$ (298,420)	$ (21,671)	$ (14,666)	$ (14,666)	$ (15,041)	$ (12,522)	$ 1,306	$ 7,387	$ 19,780	$ 29,695	$ 24,328	$ 22,593	$ 10,348	$ 27,504	$ 49,518	$ 68,351	$ 59,787	$ (59,218)
35. Medium General Service	$ (175,141)	$ (13,522)	$ (9,411)	$ (9,009)	$ (10,851)	$ (8,764)	$ 1,694	$ 5,701	$ 12,935	$ 17,144	$ 14,949	$ 12,072	$ 6,399	$ 15,540	$ 27,293	$ 38,671	$ 29,658	$ (45,713)
36. Large General Service	$ (491,237)	$ (32,007)	$ (23,268)	$ (25,783)	$ (29,159)	$ (18,641)	$ 6,205	$ 13,930	$ 32,125	$ 41,429	$ 31,779	$ 24,674	$ 10,729	$ 35,725	$ 61,396	$ 77,258	$ 60,658	$ (130,776)
37 Total (Over)/Under Recovery		$ (140,395)	$ (88,787)	$ (87,798)	$ (90,778)	$ (54,831)	$ 16,433	$ 38,917	$ 112,156	$ 167,089	$ 148,184	$ 135,265	$ 82,844	$ 123,100	$ 343,601	$ 342,202	$ 318,463	$ (478,924)
38. Cumulative (Over)/Under Recovery	$ (1,709,008)	$ (1,849,394)	$ (1,938,181)	$ (2,025,979)	$ (2,116,757)	$ (2,171,276)	$ (2,154,845)	$ (2,117,928)	$ (2,005,772)	$ (1,838,683)	$ (1,692,499)	$ (1,557,234)	$ (1,504,690)	$ (1,381,590)	$ (1,138,589)	$ (796,387)	$ (478,924)	

EXHIBIT NO. ___ (AWR-5)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF DISTRIBUTED ENERGY RESOURCE PROGRAM AVOIDED COSTS
MAY 2018 - APRIL 2019

	Balance of Costs @ 4/30/2018	Forecast May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	Balance of Costs @ 4/30/2019
DERP Avoided Costs														
1. BCA Avoided Costs		$ 105,181	$ 104,120	$ 104,511	$ 98,751	$ 87,818	$ 82,981	$ 68,111	$ 64,705	$ 65,283	$ 78,555	$ 94,071	$ 111,545	
2. Utility Scale Avoided Costs		$ 489,703	$ 484,765	$ 486,584	$ 450,454	$ 408,666	$ 368,252	$ 317,111	$ 301,256	$ 303,855	$ 370,397	$ 437,978	$ 519,335	
3. Community Solar Avoided Costs		$ 119,787	$ 118,559	$ 119,004	$ 110,168	$ 99,997	$ 94,488	$ 77,556	$ 73,678	$ 74,314	$ 103,529	$ 122,419	$ 145,159	
4 Excess NEM Avoided Cost Payments		$ -	$ -	$ -	$ -	$ -	$ -	$ 89,159	$ -	$ -	$ -	$ -	$ -	
5. Total DERP Avoided Costs		$ 714,651	$ 707,444	$ 710,099	$ 657,373	$ 596,481	$ 563,679	$ 551,937	$ 439,638	$ 443,432	$ 553,481	$ 654,468	$ 776,039	
Demand Allocations														
6 Residential		47.36%	47.36%	47.36%	47.36%	47.36%	47.36%	47.36%	47.36%	47.36%	47.36%	47.36%	47.36%	
7. Small General Service		18.99%	18.99%	18.99%	18.99%	18.99%	18.99%	18.99%	18.99%	18.99%	18.99%	18.99%	18.99%	
8. Medium General Service		10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	10.16%	
9. Large General Service		23.49%	23.49%	23.49%	23.49%	23.49%	23.49%	23.49%	23.49%	23.49%	23.49%	23.49%	23.49%	
DERP Avoided Cost Allocation														
10. Residential		$ 338,459	$ 335,045	$ 336,303	$ 311,332	$ 282,588	$ 266,958	$ 261,397	$ 208,213	$ 210,008	$ 262,129	$ 309,956	$ 367,632	
11. Small General Service		$ 135,712	$ 134,344	$ 134,848	$ 124,835	$ 113,310	$ 107,043	$ 104,813	$ 83,487	$ 84,208	$ 105,106	$ 124,283	$ 147,370	
12. Medium General Service		$ 72,609	$ 71,876	$ 72,146	$ 66,789	$ 60,623	$ 57,270	$ 56,077	$ 44,667	$ 45,053	$ 56,234	$ 66,494	$ 78,848	
13 Large General Service		$ 167,872	$ 166,179	$ 166,802	$ 154,417	$ 140,160	$ 132,408	$ 129,650	$ 103,271	$ 104,162	$ 130,013	$ 153,735	$ 182,292	
14. Net Environmental Cost Allocation		$ 714,652	$ 707,444	$ 710,099	$ 657,373	$ 596,681	$ 563,679	$ 551,937	$ 439,638	$ 443,432	$ 553,482	$ 654,468	$ 776,040	
Allocation of Unbilled Fuel Cost Adj.														
15. Residential		$ (17,936)	$ (16,838)	$ (11,432)	$ 3,560	$ 27,118	$ 15,362	$ (20,946)	$ (13,886)	$ (6,887)	$ 33,959	$ 7,581	$ 324	
16. Small General Service		$ (7,192)	$ (5,751)	$ (4,564)	$ 1,427	$ 10,873	$ 6,159	$ (8,399)	$ (5,566)	$ (2,762)	$ 13,616	$ 3,040	$ 130	
17. Medium General Service		$ (3,846)	$ (3,612)	$ (2,452)	$ 764	$ 5,818	$ 3,295	$ (4,493)	$ (2,975)	$ (1,477)	$ 7,285	$ 1,627	$ 69	
18. Large General Service		$ (8,886)	$ (8,350)	$ (5,670)	$ 1,766	$ 13,450	$ 7,619	$ (10,389)	$ (6,877)	$ (3,416)	$ 16,843	$ 3,761	$ 160	
19. Unbilled Fuel Adjustment		$ (37,872)	$ (35,548)	$ (24,138)	$ 7,517	$ 57,259	$ 32,435	$ (44,227)	$ (29,278)	$ (14,542)	$ 71,703	$ 16,009	$ 683	
Total DERP Avoided Costs by Class														
20. Residential	$ (241,271)	$ 320,523	$ 318,209	$ 324,871	$ 314,892	$ 309,706	$ 282,320	$ 240,451	$ 194,327	$ 203,122	$ 296,088	$ 317,537	$ 367,956	$ 3,248,651
21. Small General Service	$ (59,216)	$ 128,520	$ 127,593	$ 130,284	$ 126,262	$ 124,183	$ 113,202	$ 96,414	$ 77,927	$ 81,446	$ 118,722	$ 127,323	$ 147,500	$ 1,340,136
22. Medium General Service	$ (46,713)	$ 68,761	$ 68,264	$ 69,694	$ 67,553	$ 66,441	$ 60,565	$ 51,584	$ 41,692	$ 43,576	$ 83,519	$ 69,121	$ 78,915	$ 701,972
23. Large General Service	$ (132,722)	$ 158,976	$ 157,829	$ 161,132	$ 156,183	$ 153,610	$ 140,027	$ 119,281	$ 96,394	$ 100,746	$ 146,856	$ 157,496	$ 182,452	$ 1,669,240
24. Total Environ. & Avoided Cap. Costs	$ (479,924)	$ 676,780	$ 671,895	$ 685,981	$ 664,890	$ 653,940	$ 596,114	$ 507,710	$ 410,360	$ 428,890	$ 625,185	$ 670,477	$ 776,723	$ 6,689,001
Class Sales (in kWh)														
25. Residential		625,500,000	690,500,000	827,200,000	853,000,000	674,600,000	532,600,000	456,800,000	643,000,000	789,500,000	736,700,000	583,600,000	488,300,000	7,811,700,000
26. Small General Service		281,500,000	319,200,000	344,900,000	364,000,000	328,600,000	292,700,000	242,100,000	261,800,000	299,600,000	290,380,000	284,400,000	257,400,000	3,544,700,000
27. Medium General Service		163,200,000	199,700,000	211,300,000	220,300,000	199,100,000	187,100,000	161,700,000	165,400,000	178,600,000	168,400,000	163,000,000	175,100,000	2,209,900,000
28. Large General Service		711,200,000	742,900,000	768,800,000	776,900,000	740,900,000	715,300,000	674,900,000	675,300,000	652,700,000	615,800,000	643,700,000	655,000,000	8,371,400,000
DERP Avoided Cost Factors (per kWh)														
29 Residential		$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042
30. Small General Service		$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038	$ 0.00038
31. Medium General Service		$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032	$ 0.00032
32. Large General Service		$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019	$ 0.00019
DERP Avoided Cost Revenue Recovered														
33. Residential		$ 220,710	$ 290,010	$ 347,424	$ 358,260	$ 283,416	$ 223,776	$ 191,655	$ 270,060	$ 335,790	$ 309,414	$ 245,112	$ 205,096	
34. Small General Service		$ 106,970	$ 121,296	$ 131,082	$ 138,320	$ 124,108	$ 111,226	$ 91,996	$ 99,484	$ 113,924	$ 110,314	$ 100,472	$ 97,812	
35. Medium General Service		$ 58,634	$ 63,904	$ 67,616	$ 70,496	$ 63,392	$ 59,872	$ 51,744	$ 52,928	$ 57,152	$ 53,248	$ 52,160	$ 56,032	
36. Large General Service		$ 135,128	$ 141,151	$ 145,592	$ 147,611	$ 140,771	$ 135,907	$ 128,231	$ 126,307	$ 124,013	$ 117,002	$ 122,303	$ 124,450	
37. Total Environmental Revenue		$ 521,432	$ 616,361	$ 691,794	$ 714,687	$ 611,687	$ 530,781	$ 463,629	$ 550,779	$ 630,879	$ 589,978	$ 520,047	$ 483,380	
DERP Avoided (Over)/Under Recovery														
38. Residential	$ (241,271)	$ 99,813	$ 28,199	$ (22,553)	$ (43,368)	$ 26,290	$ 58,544	$ 48,595	$ (75,713)	$ (132,668)	$ (13,326)	$ 72,425	$ 162,770	$ (32,263)
39. Small General Service	$ (59,216)	$ 21,550	$ 6,297	$ (796)	$ (12,056)	$ 75	$ 1,976	$ 4,418	$ (21,557)	$ (32,478)	$ 8,408	$ 26,851	$ 49,688	$ (6,848)
40. Medium General Service	$ (46,713)	$ 10,137	$ 4,360	$ 2,078	$ (2,943)	$ 3,049	$ 693	$ (160)	$ (11,236)	$ (13,576)	$ 10,271	$ 15,861	$ 22,883	$ (5,196)
41. Large General Service	$ (132,722)	$ 23,848	$ 16,678	$ 15,440	$ 6,572	$ 12,839	$ 4,120	$ (6,970)	$ (31,913)	$ (23,267)	$ 29,854	$ 35,193	$ 58,002	$ 7,674
42. Total (Over)/Under Recovery		$ 155,348	$ 55,534	$ (5,833)	$ (49,797)	$ 42,253	$ 65,333	$ 43,861	$ (140,419)	$ (201,989)	$ 35,207	$ 150,430	$ 293,343	$ (36,633)
43. Cumulative (Over)/Under Recovery	$ (479,924)	$ (324,576)	$ (269,042)	$ (274,875)	$ (324,672)	$ (282,419)	$ (217,086)	$ (173,205)	$ (313,624)	$ (515,613)	$ (480,406)	$ (329,976)	$ (36,633)	

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF DISTRIBUTED ENERGY RESOURCE PROGRAM INCREMENTAL COSTS
JANUARY 2017 - APRIL 2018

	12/31/2016 Balance	Actual Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017
DERP Incremental Costs									
1. NEM Incentive		$ 140,765	$ 162,508	$ 232,033	$ 244,329	$ 361,255	$ 532,188	$ 576,420	$ 582,798
2. NEM Future Benefits		$ 15,507	$ 22,418	$ 31,473	$ 38,963	$ 5,458	$ 5,775	$ 5,431	$ 5,545
3. NEM PBI		$ 15,644	$ 20,643	$ 27,052	$ 29,427	$ 33,936	$ 33,105	$ 29,748	$ 29,313
4. DER Depreciation Costs		$ 17,701	$ 17,714	$ 17,732	$ 19,726	$ 19,735	$ 19,734	$ 23,243	$ 23,280
5. BCA Incentive		$ 36,598	$ 48,048	$ 61,071	$ 92,171	$ 118,979	$ 134,583	$ 141,997	$ 167,635
6. Community Solar		$ -	$ -	$ -	$ -	$ -	$ -		$ -
7. Utility Scale Incentive		$ 10,543	$ 13,567	$ 15,684	$ 16,577	$ 17,658	$ 26,354	$ 42,216	$ 55,446
8 Administrative & General Expenses		$ 228,051	$ 164,522	$ 149,668	$ 166,925	$ 175,667	$ 234,166	$ 165,090	$ 152,838
9. Carrying Costs		$ 17,883	$ 18,167	$ 18,407	$ 20,534	$ 20,841	$ 17,978	$ 20,839	$ 20,311
10. Total DERP Incremental Costs		$ 482,691	$ 487,806	$ 573,121	$ 626,653	$ 753,530	$ 1,003,883	$ 1,004,945	$ 1,037,176
11 Revenue Recovery		$ 363,110	$ 362,545	$ 363,970	$ 364,219	$ 916,714	$ 917,568	$ 917,767	$ 916,969
12. Monthly (Over)/Under		$ 119,581	$ 125,061	$ 209,151	$ 262,434	$ (163,184)	$ 86,315	$ 87,158	$ 120,207
13. Adjustments		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14 Unbilled DERP Incremental Revenue		$ 16,821	$ (9,307)	$ 14,185	$ (21,341)	$ (247,225)	$ 49,416	$ (36,615)	$ (4,026)
15. Balance @ Period Ending	$ 698,707	$ 835,109	$ 950,863	$ 1,174,200	$ 1,415,292	$ 1,004,883	$ 1,140,614	$ 1,191,157	$ 1,307,338

	Actual Sep 2017	Oct 2017	Nov 2017	Dec 2017	Forecast Jan 2018	Feb 2018	Mar 2018	Apr 2018
DERP Incremental Costs								
16 NEM Incentive	$ 524,911	$ 418,110	$ 338,056	$ 302,705	$ 339,191	$ 531,289	$ 651,088	$ 799,141
17 NEM Future Benefits	$ 5,365	$ 5,048	$ 4,292	$ 3,746	$ 4,110	$ 5,661	$ 6,936	$ 8,513
18 NEM PBI	$ 27,253	$ 25,002	$ 20,101	$ 16,869	$ 17,643	$ 24,007	$ 28,387	$ 33,660
19 DER Depreciation Costs	$ 23,306	$ 26,838	$ 26,779	$ 28,816	$ 28,852	$ 29,607	$ 29,996	$ 33,849
20. BCA Incentive	$ 169,807	$ 164,951	$ 145,356	$ 126,048	$ 143,734	$ 199,297	$ 291,731	$ 413,809
21 Community Solar					$ -	$ -	$ -	$ -
22. Utility Scale Incentive	$ 70,644	$ 63,101	$ 48,307	$ 46,459	$ 73,048	$ 89,045	$ 105,292	$ 124,851
23. Administrative & General Exponses	$ 121,459	$ 81,784	$ 116,671	$ 206,445	$ 122,974	$ 168,000	$ 168,000	$ 168,000
24. Carrying Costs	$ 19,946	$ 22,875	$ 24,284	$ 23,780	$ 26,466	$ 30,183	$ 33,598	$ 39,864
25. Total DERP Incremental Costs	$ 962,691	$ 807,707	$ 724,056	$ 754,868	$ 756,018	$ 1,076,089	$ 1,315,028	$ 1,621,687
26. Revenue Recovery	$ 917,611	$ 918,558	$ 919,195	$ 921,121	$ 923,894	$ 923,894	$ 923,894	$ 923,894
27. Monthly (Over)/Under	$ 45,080	$ (110,851)	$ (195,139)	$ (166,253)	$ (167,876)	$ 152,195	$ 391,134	$ 697,793
28. Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29 Unbilled DERP Incremental Revenue	$ 5,483	$ (29,914)	$ (61,155)	$ 3,450	$ -	$ -	$ -	$ -
30. Balance @ Period Ending	$ 1,357,901	$ 1,217,136	$ 960,842	$ 798,039	$ 630,163	$ 782,358	$ 1,173,492	$ 1,871,285

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF DISTRIBUTED ENERGY RESOURCE PROGRAM INCREMENTAL COSTS
MAY 2018 - APRIL 2019

	4/30/2018 Balance	Forecast May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019
DERP Incremental Costs													
1. NEM Incentive		$ 609,405	$ 627,528	$ 657,019	$ 617,809	$ 764,478	$ 743,137	$ 627,308	$ 612,278	$ 634,037	$ 792,969	$ 991,400	$ 1,168,147
2. NEM Future Benefits		$ (5,089)	$ (5,202)	$ (5,387)	$ (5,140)	$ (4,805)	$ (4,670)	$ (3,942)	$ (3,648)	$ (3,884)	$ (4,983)	$ (6,041)	$ (7,339)
3. NEM PBI		$ 31,740	$ 31,420	$ 31,537	$ 29,196	$ 26,500	$ 25,035	$ 20,553	$ 19,526	$ 19,894	$ 24,007	$ 28,387	$ 33,660
4. DER Depreciation Costs		$ 34,220	$ 35,061	$ 35,432	$ 35,803	$ 36,175	$ 36,546	$ 38,917	$ 37,288	$ 37,659	$ 38,030	$ 38,401	$ 38,772
5. BCA Incentive		$ 399,664	$ 395,633	$ 397,118	$ 367,631	$ 333,689	$ 315,234	$ 259,805	$ 245,885	$ 247,997	$ 302,293	$ 357,449	$ 423,847
6. Community Solar		$ 207,667	$ 205,660	$ 206,599	$ 191,917	$ 175,017	$ 165,827	$ 137,731	$ 131,288	$ 132,344	$ 182,153	$ 213,539	$ 251,324
7. Utility Scale Incentive		$ 117,727	$ 116,540	$ 116,977	$ 108,291	$ 98,293	$ 92,857	$ 76,235	$ 72,423	$ 73,048	$ 89,045	$ 105,282	$ 124,851
8. Administrative & General Expenses		$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000	$ 168,000
9. Carrying Costs		$ 45,345	$ 48,465	$ 51,988	$ 55,835	$ 59,106	$ 62,701	$ 65,321	$ 69,965	$ 73,634	$ 77,328	$ 81,049	$ 84,792
10. Total DERP Incremental Costs		$ 1,608,679	$ 1,623,305	$ 1,658,283	$ 1,769,042	$ 1,656,450	$ 1,604,667	$ 1,387,928	$ 1,352,785	$ 1,382,419	$ 1,668,842	$ 1,947,475	$ 2,280,054
15. Balance @ Period Ending	$ 1,871,265	$ 3,479,184	$ 5,101,489	$ 7,360,752	$ 9,129,794	$ 10,786,244	$ 12,390,911	$ 13,778,839	$ 15,131,624	$ 16,514,043	$ 18,182,885	$ 20,130,360	$ 22,416,414
Demand Allocations													
16. Residential													47.36%
17. Small & Medium General Service													29.15%
18. Large General Service													23.49%
Class Allocation of Costs													
19. Residential													$ 10,616,414
20. Small & Medium General Service													$ 6,534,385
21. Large General Service													$ 5,265,618
Average Customers													
22. Residential													628,180
23. Small & Medium General Service													101,480
24. Large General Service													320
Annual Rate Calculation													
25. Residential													$ 16.90
26. Small & Medium General Service													$ 64.39
27. Large General Service													$ 16,455.05
Monthly Rate Calculation													
28. Residential [1]													$ 1.00
29. Small & Medium General Service													$ 5.37
30. Large General Service [2]													$ 100.00

[1] - Residential Incremental Charges per Account are capped at $1 per month in compliance with S.C. Code Ann. § 58-39-150.
[2] - Large General Service Incremental Charges per Account are capped at $100 per month in compliance with S.C. Code Ann. § 58-39-150.

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EXHIBIT NO. ___ (AWR-9)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SUMMARY OF BASE FUEL COSTS
COMPANY PROPOSAL TO MAINTAIN BASE FUEL COMPONENT AT CURRENT LEVEL
MAY 2018 - APRIL 2019

		Forecast					
	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018
1. Fossil Fuel Costs	$ 34,187,000	$ 39,043,000	$ 41,480,000	$ 42,252,000	$ 33,349,000	$ 38,039,000
2. Nuclear Fuel Costs	$ 4,727,000	$ 4,472,000	$ 4,619,000	$ 4,701,000	$ 4,472,000	$ 783,000
3. Fuel Costs in Purchased Power and Interchange Received	$ 13,827,000	$ 16,204,000	$ 17,295,000	$ 17,405,000	$ 15,276,000	$ 14,638,000
4. Less: Fuel Costs in Intersystem Sales	$ 69,000	$ 93,000	$ 70,000	$ 46,000	$ 188,000	$ 71,000
5. Total Fuel Costs (Lines 1+2+3-4)	$ 52,682,000	$ 59,626,000	$ 63,324,000	$ 64,312,000	$ 52,905,000	$ 53,369,000
6. Total System Sales Excluding Intersystem Sales (kWh)	1,801,100,000	2,062,100,000	2,267,200,000	2,327,700,000	2,040,300,000	1,819,200,000
7. Total Fuel Cost Per kWh Sales	$ 0.029250	$ 0.028915	$ 0.027930	$ 0.027629	$ 0.025930	$ 0.029337
8. Less Base Fuel Cost Per kWh Included in Rates	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451
9. Fuel Adjustment Per kWh	$ 0.00474	$ 0.00441	$ 0.00342	$ 0.00312	$ 0.00142	$ 0.00483
10. Retail kWh Sales	1,726,600,000	1,977,400,000	2,176,500,000	2,238,900,000	1,965,000,000	1,753,600,000
11. Over / Under Recovery Revenue	$ 8,184,084	$ 8,720,334	$ 7,443,630	$ 6,985,388	$ 2,760,300	$ 8,469,888
12. Estimated Carrying Costs	$ -	$ -	$ -	$ -	$ -	$ -
13. Fixed Capacity Charges & Adjustments	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)
14. Unbilled Fuel Cost Recovery Adjustment	$ (2,651,216)	$ (2,474,772)	$ (1,721,148)	$ 493,448	$ 4,018,124	$ 2,302,980
15. Net Over / Under Recovery Revenue	$ 3,948,594	$ 4,661,288	$ 4,138,208	$ 5,894,542	$ 5,224,150	$ 9,188,594
16. Cumulative (Over) Under Balance $ (50,536,981)	$ (46,588,387)	$ (41,927,099)	$ (37,788,891)	$ (31,894,349)	$ (26,670,199)	$ (17,481,605)

	Forecast					
	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019
17. Fossil Fuel Costs	$ 43,187,000	$ 38,060,000	$ 39,452,000	$ 32,842,000	$ 27,100,000	$ 26,828,000
18. Nuclear Fuel Costs	$ 1,037,000	$ 4,594,000	$ 4,594,000	$ 4,147,000	$ 4,594,000	$ 4,442,000
19. Fuel Costs in Purchased Power and Interchange Received	$ 10,051,000	$ 12,112,000	$ 12,416,000	$ 10,848,000	$ 11,439,000	$ 10,179,000
20. Less: Fuel Costs in Intersystem Sales	$ 98,000	$ 76,000	$ 75,000	$ 144,000	$ 178,000	$ 105,000
21. Total Fuel Costs (Lines 1+2+3-4)	$ 54,177,000	$ 54,690,000	$ 56,387,000	$ 47,691,000	$ 42,957,000	$ 41,344,000
22. Total System Sales Excluding Intersystem Sales (kWh)	1,629,300,000	1,848,400,000	2,059,000,000	1,926,200,000	1,771,400,000	1,687,200,000
23. Total Fuel Cost Per kWh Sales	$ 0.033252	$ 0.029588	$ 0.027388	$ 0.024759	$ 0.024250	$ 0.024505
24. Less Base Fuel Cost Per kWh Included in Rates	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451	$ 0.02451
25. Fuel Adjustment Per kWh	$ 0.00874	$ 0.00508	$ 0.00288	$ 0.00025	$ (0.00026)	$ (0.00001)
26. Retail kWh Sales	1,560,300,000	1,770,400,000	1,955,300,000	1,834,500,000	1,679,600,000	1,601,300,000
27. Over / Under Recovery Revenue	$ 13,637,022	$ 8,993,632	$ 5,631,284	$ 458,925	$ (436,696)	$ (16,013)
28. Estimated Carrying Costs	$ -	$ -	$ -	$ -	$ -	$ -
29. Fixed Capacity Charges & Adjustments	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)	$ (1,584,274)
30 Unbilled Fuel Cost Recovery Adjustment	$ (3,087,910)	$ (2,021,378)	$ (1,048,828)	$ 5,072,859	$ 1,072,956	$ 44,785
31. Net Over / Under Recovery Revenue	$ 8,964,838	$ 5,387,980	$ 2,998,182	$ 3,947,310	$ (948,014)	$ (1,555,502)
32. Cumulative (Over) Under Balance	$ (8,516,767)	$ (3,128,787)	$ (130,625)	$ 3,816,685	$ 2,868,671	$ 1,313,169

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
CALCULATION OF TOTAL FUEL COST FACTORS BY CUSTOMER CLASS
FOR THE PERIOD MAY 2018 THROUGH APRIL 2019

	Cents / kWh			
Class	Base Fuel Cost Component (from Exhibit 10)	Variable Environmental and Avoided Capacity Cost Component (from Exhibit 5)	Distributed Energy Resource Program Avoided Costs Component (from Exhibit 7)	Total Fuel Costs Factor
Residential	2.451	0.083	0.042	2.576
Small General Service	2.451	0.075	0.038	2.564
Medium General Service	2.451	0.063	0.032	2.546
Large General Service	2.451	0.039	0.019	2.509
Lighting	2.451	0.000	0.000	2.451

	Costs Per Account Per Month
Class	Distributed Energy Resource Program Incremental Costs Component (from Exhibit 9)
Residential	$1.00
Small / Medium General Service	$5.37
Large General Service	$100.00

EXHIBIT NO. ___ (AWR-11)

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

APPLICABILITY

This adjustment is applicable to and is part of the Utility's South Carolina retail electric rate schedules.

The fuel, variable environmental & avoided capacity, and DER avoided costs, to be recovered in an amount rounded to the nearest one-thousandth of a cent per kilowatt-hour, will be determined by the following formulas:

$$F_C = \frac{E_F}{S} + \frac{G_F}{S_1}$$

$$F_{EC} = \frac{E_{EC} + G_{EC}}{S_2}$$

$$F_{AC} = \frac{E_{AC} + G_{AC}}{S_2}$$

Total Fuel Rate per kWh $= F_C + F_{EC} + F_{AC}$

Where:

F_C = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one-thousandth of a cent.

E_F = Total projected system fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

PLUS

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel costs associated with energy purchased are identifiable and are identified in the billing statement, and also including avoided energy costs incurred by the Utility. Also, the cost of "firm generation capacity purchases," which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. Costs of "firm generation capacity purchases" includes the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

PLUS

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing Utility's avoided variable costs for the generation of an equivalent quantity of electric power.

Energy receipts that do not involve money payments such as diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

MINUS

(D) The cost of fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G_F = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E_F and S.

S_1 = Projected jurisdictional kilowatt-hour sales, for the period covered by the fuel costs included in E_F.

F_{EC} = Customer class variable environmental and avoided capacity costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

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ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

RETAIL RATES
(Page 2 of 2)

E_{EC} = The projected variable environmental costs including: a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, plus b) the cost of emission allowances, as used, including allowances for SO2, NOx, mercury and particulates minus net proceeds of sales of emission allowances, and c) as approved by the Commission, all other variable environmental costs incurred in relation to the consumption of fuel and air emissions caused thereby, including but not limited to environmental reagents, other environmental allowances, and emission related taxes. Any environmental related costs recovered through intersystem sales would be subtracted from the totals produced by subparts a), b), and c). This component also includes avoided capacity costs incurred by the Utility.

These environmental and avoided capacity costs will be allocated to retail customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{EC} = Cumulative difference between jurisdictional customer class environmental fuel revenues billed and jurisdictional customer class environmental costs at the end of the month preceding the projected period utilized in E_{EC} and S_2.

F_{AC} = Customer class DER avoided costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

E_{AC} = The projected DER avoided costs paid to distributed generators as most recently determined by the Public Service Commission of South Carolina. These avoided costs will be allocated to retail electric customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{AC} = Cumulative difference between jurisdictional customer class avoided cost revenues billed and jurisdictional customer class avoided costs at the end of the month preceding the projected period utilized in E_{AC} and S_2.

S_2 = The projected jurisdictional customer class kilowatt-hour sales.

The appropriate revenue-related tax factor is to be included in these calculations.

FUEL RATES PER KWH BY CLASS

The total fuel costs in cents per kilowatt-hour by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2018 through April, 2019:

Customer Class	F_C Rate	+	F_{EC} Rate	+	F_{AC} Rate	=	Total Fuel Rate
Residential	2.451		0.083		0.042		2.576
Small General Service	2.451		0.075		0.038		2.564
Medium General Service	2.451		0.063		0.032		2.546
Large General Service	2.451		0.039		0.019		2.509
Lighting	2.451		0.000		0.000		2.451

The incremental costs associated with SCE&G's Distributed Energy Resource Programs, to be recovered in an amount rounded to the nearest cent per account, will be determined by the following formulas:

Total Fuel Rate per Account

$$F_{IC} = \frac{E_{DC} + G_{DC}}{C}$$

Where:

F_{IC} = Fuel cost per account included in base rate, rounded to the nearest cent, not to exceed $12 for residential customers, $120 for small/medium general service customers, and $1,200 for large general service customers.

E_{DC} = The projected incremental costs associated with SCE&G's Distributed Energy Resource Program as determined by the Public Service Commission of South Carolina

G_{DC} = Cumulative difference between jurisdictional customer class distributed energy component revenues billed and jurisdictional customer class incremental costs associated with SCE&G's Distribued Energy Resource Program at the end of the month preceding the projected period utilized in E_{DC} and C.

C = The jurisdictional customer class account totals.

FUEL RATES PER ACCOUNT PER MONTH BY CLASS

The total fuel costs in dollars per account by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2018 through April, 2019:

Customer Class	F_{IC} Rate
Residential	$ 1.00
Small & Medium General Service	$ 5.37
Large General Service	$ 100.00

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SOUTH CAROLINA ELECTRIC & GAS COMPANY — ELECTRICITY

RATE PR-1 — SMALL POWER PRODUCTION, COGENERATION

AVAILABILITY

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

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATE FOR NON-SOLAR QUALIFYING FACILITIES
(Seller Charges & Credits)

For Qualifying Facilities, Company will pay Seller a monthly credit equal to the Energy Credit and the Capacity Credit reduced by the Seller Charge.

I. Energy Credit:

Company shall pay Seller the following rates per KWH for energy delivered by the Seller to Company's system.

		Summer (June -September)		Winter (October-May)	
1.	On-Peak	~~$0.03590~~	$0.03233	~~$0.03831~~	$0.03445
2.	Off-Peak	~~$0.03079~~	$0.02886	~~$0.03640~~	$0.03298

The South Carolina Power Excise Tax of $.0005 per KWH is included in the energy credits above.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS FOR ENERGY CREDITS

A. On-Peak Hours:

Summer Months of June - September:

The on-peak Summer hours are defined to be 10:00 a.m.-10:00 p.m. Monday-Friday.

Winter Months of October - May:

1. November through April: The on-peak hours are defined as those hours between 6:00 a.m.-1:00 p.m. and 5:00 p.m.-10:00 p.m., Monday-Friday.
2. October and May: The on-peak hours are defined as those hours between 10:00 a.m.-10:00p.m., Monday-Friday.

B. Off-Peak Hours:

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

II. Capacity Credit:

In addition to the energy credit, the Company shall pay the Seller ~~$0.0270~~ $0.00000 per kWh for energy delivered by the Seller to the Company's system during the on-peak hours defined for energy credits above ~~critical peak Summer hours~~. ~~The Company shall pay the Seller $0.0771 per kWh for energy delivered by the Seller to the Company's system during critical peak Winter hours.~~

~~DETERMINATION OF CRITICAL PEAK HOURS FOR CAPACITY CREDITS~~

~~A. Critical Peak Hours:~~

~~Summer Months of June - August~~

~~The critical peak Summer hours are defined to be 2:00 p.m. - 6:00 p.m. Monday-Friday.~~

~~Winter Months of December - February~~

~~The critical peak Winter hours are defined to be 6:00 a.m. - 9:00 a.m. Monday-Friday~~

MONTHLY RATE FOR SOLAR QUALIFYING FACILITIES
(Seller Charges & Credits)

I. Energy Credit:

Company shall pay Seller the following rates per KWH for energy delivered by the Seller to Company's system

All kWh: $0.03256

The South Carolina Power Excise Tax of $.0005 per KWH is included in the energy credits above.

II. Capacity Credit:

In addition to the energy credit, the Company shall pay the Seller $0.00000 per kWh for energy delivered by the Seller to the Company's system

III. Seller Charge (Applicable to both Non-Solar and Solar Qualifying Facilities):

Seller shall pay the following Seller Charge each monthly billing period $ 4.50

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from Qualifying Facility until such facility and Company have executed an Agreement for Purchase of Power from Small Power Production facility or Cogeneration Facility.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY — ELECTRICITY

RATE PR-1 — SMALL POWER PRODUCTION, COGENERATION

AVAILABILITY

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

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATE FOR NON-SOLAR QUALIFYING FACILITIES
(Seller Charges & Credits)

For Qualifying Facilities, Company will pay Seller a monthly credit equal to the Energy Credit and the Capacity Credit reduced by the Seller Charge.

I. Energy Credit:

Company shall pay Seller the following rates per KWH for energy delivered by the Seller to Company's system.

		Summer (June -September)	Winter (October-May)
1.	On-Peak	$0.03233	$0.03445
2.	Off-Peak	$0.02886	$0.03298

The South Carolina Power Excise Tax of $.0005 per KWH is included in the energy credits above.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS FOR ENERGY CREDITS

A. On-Peak Hours:

Summer Months of June - September:

The on-peak Summer hours are defined to be 10:00 a.m.-10:00 p.m. Monday-Friday.

Winter Months of October - May:

1. November through April: The on-peak hours are defined as those hours between 6:00 a.m.-1:00 p.m. and 5:00 p.m.-10:00 p.m., Monday-Friday.
2. October and May: The on-peak hours are defined as those hours between 10:00 a.m.-10:00p.m., Monday-Friday.

B. Off-Peak Hours:

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

II. Capacity Credit:

In addition to the energy credit, the Company shall pay the Seller $0.00000 per kWh for energy delivered by the Seller to the Company's system during the on-peak hours defined for energy credits above.

MONTHLY RATE FOR SOLAR QUALIFYING FACILITIES
(Seller Charges & Credits)

I. Energy Credit:

Company shall pay Seller the following rates per KWH for energy delivered by the Seller to Company's system.

All kWh: $0.03256

The South Carolina Power Excise Tax of $.0005 per KWH is included in the energy credits above.

II. Capacity Credit:

In addition to the energy credit, the Company shall pay the Seller $0.00000 per kWh for energy delivered by the Seller to the Company's system.

Seller Charge (Applicable to both Non-Solar and Solar Qualifying Facilities):

Seller shall pay the following Seller Charge each monthly billing period $ 4.50

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from Qualifying Facility until such facility and Company have executed an Agreement for Purchase of Power from Small Power Production facility or Cogeneration Facility.

Effective Upon Approval of the
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RATE PR-2 SOLAR ~~SMALL~~ POWER PRODUCTION, ~~COGENERATION~~

AVAILABILITY

Available to ~~Small~~ Power Producers deploying Solar PV generation ~~and Cogenerators~~ that are a Qualifying Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54 that have power production capacity greater than 100 kW and less than or equal to 80 MW, and entering into a power purchase agreement ("Seller") with South Carolina Electric & Gas Company. This schedule is not available for Qualifying Facilities that have power production capacity greater than 80 MW or equal to or less than 100 KW.

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATES

For a Qualifying Facility as described in the Availability section above, the Company will pay Seller an amount equal to the Energy Payment and the Capacity Payment reduced by the Seller Charge. The Company will pay this amount monthly.

I. Energy Payment:

Company shall pay the Seller the following rates per kWh for energy delivered by the Seller to Company's system:

A. For the period 2017~~8~~ - 2021~~2~~:

All kWh: $ 0.02853

		~~For Energy Supplied at Transmission Level~~		~~For Energy Supplied at Distribution Level~~	
		~~Summer (Jun – Sep.)~~	~~Non-Summer (Oct. – May)~~	~~Summer (Jun – Sep.)~~	~~Non-Summer (Oct. – May)~~
1.	~~On-Peak~~	~~$ 0.03384~~	~~$ 0.03483~~	~~$ 0.03384~~	~~$ 0.03483~~
2.	~~Off-Peak~~	~~$ 0.02845~~	~~$ 0.03170~~	~~$ 0.02845~~	~~$ 0.03170~~

B. For the period 2022~~3~~ - 2026~~7~~:

All kWh: $ 0.02994

		~~For Energy Supplied at Transmission Level~~		~~For Energy Supplied at Distribution Level~~	
		~~Summer (Jun – Sep.)~~	~~Non-Summer (Oct. – May)~~	~~Summer (Jun – Sep.)~~	~~Non-Summer (Oct. – May)~~
1.	~~On-Peak~~	~~$ 0.03645~~	~~$ 0.03200~~	~~$ 0.03645~~	~~$ 0.03200~~
2.	~~Off-Peak~~	~~$ 0.02679~~	~~$ 0.02726~~	~~$ 0.02679~~	~~$ 0.02726~~

C. For the period 2027~~8~~ - 2031~~2~~:

All kWh: $ 0.03414

		~~For Energy Supplied at Transmission Level~~		~~For Energy Supplied at Distribution Level~~	
		~~Summer (Jun – Sep.)~~	~~Non-Summer (Oct. – May)~~	~~Summer (Jun – Sep.)~~	~~Non-Summer (Oct. – May)~~
1.	~~On-Peak~~	~~$ 0.04070~~	~~$ 0.03587~~	~~$ 0.04070~~	~~$ 0.03587~~
2.	~~Off-Peak~~	~~$ 0.03040~~	~~$ 0.02936~~	~~$ 0.03040~~	~~$ 0.02936~~

The South Carolina Power Excise Tax of $.0005 per kWh is included in the energy payments above.

~~Transmission Level is defined as voltages equal to or greater than 23 kV. Distribution Level is defined as voltages less than 23 kV.~~

~~DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS FOR ENERGY PAYMENTS~~

~~A. On-Peak Hours:~~

~~Summer Months of June - September~~

~~The on-peak Summer hours are defined to be 10:00 a.m. – 10:00 p.m. Monday-Friday.~~

~~Non-Summer Months of October – May.~~

1. ~~November through April. The on-peak hours are defined as those hours between 6:00 a.m. - 1:00 p.m. and 5:00 p.m. 10:00 p.m. Monday-Friday.~~
2. ~~October and May. The on-peak hours are defined as those hours between 10:00 a.m. 10:00p.m., Monday Friday.~~

~~B. Off-Peak Hours:~~

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

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II. Capacity Payment:

In addition to the energy payment, the Company shall pay the Seller a ~~the following~~ capacity payment of $0.00000 per kWh for energy delivered by the Seller to the Company's system ~~during Critical Peak hours~~.

~~For Energy Supplied at Transmission Level~~		~~For Energy Supplied at Distribution Level~~	
~~Summer (Jun – Aug)~~	~~Winter (Dec – Feb)~~	~~Summer (Jun – Aug)~~	~~Winter (Dec – Feb)~~
~~$ 0.01966~~	~~$ 0.00675~~	~~$ 0.01966~~	~~$ 0.00675~~

~~Transmission Level is defined as voltages equal to or greater than 33 kV. Distribution Level is defined as voltages less than 33 kV.~~

~~DETERMINATION OF CRITICAL PEAK HOURS FOR CAPACITY PAYMENTS~~

~~A. Critical Peak Hours:~~

~~Summer Months of June – August~~

~~The critical peak Summer hours are defined to be 2:00 p.m. – 6:00 p.m. Monday-Friday~~

~~Winter Months of December – February~~

~~The critical peak Winter hours are defined to be 6:00 a.m. – 9:00 a.m. Monday-Friday~~

III. Seller Charge:

Seller shall pay the following Seller Charge each monthly billing period: $ 45.00

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month for an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from a Qualifying Facility until such facility and Company have executed a power purchase agreement.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY — ELECTRICITY

RATE PR-2 — SOLAR POWER PRODUCTION

AVAILABILITY

Available to Power Producers deploying Solar PV generation that are a Qualifying Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54 that have power production capacity greater than 100 kW and less than or equal to 80 MW, and entering into a power purchase agreement ("Seller") with South Carolina Electric & Gas Company. This schedule is not available for Qualifying Facilities that have power production capacity greater than 80 MW or equal to or less than 100 KW.

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATES

For a Qualifying Facility as described in the Availability section above, the Company will pay Seller an amount equal to the Energy Payment and the Capacity Payment reduced by the Seller Charge. The Company will pay this amount monthly.

I. Energy Payment:

Company shall pay the Seller the following rates per kWh for energy delivered by the Seller to Company's system:

A. For the period 2018 - 2022:

All kWh: $ 0.02853

B. For the period 2023 - 2027:

All kWh: $ 0.02994

C. For the period 2028 - 2032:

All kWh: $ 0.03414

The South Carolina Power Excise Tax of $.0005 per kWh is included in the energy payments above.

II. Capacity Payment:

In addition to the energy payment, the Company shall pay the Seller a capacity payment of $0.00000 per kWh for energy delivered by the Seller to the Company's system.

III. Seller Charge:

Seller shall pay the following Seller Charge each monthly billing period: $ 45.00

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month for an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from a Qualifying Facility until such facility and Company have executed a power purchase agreement.

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RIDER TO RETAIL RATES

NET ENERGY METERING FOR RENEWABLE ENERGY FACILITIES ("NEM")

AVAILABILITY

This rider is available in conjunction with the Company's Retail Electric Service Rates, for a Customer-Generator. The customer's generating system must be manufactured, installed and operated in accordance with governmental and industry standards and must fully conform with the Company's current interconnection standards as approved by the Public Service Commission of South Carolina.

This rider is available on a first come, first serve basis until the total nameplate generating capacity of net energy metering systems equals 2% of the previous five-year average of the Company's South Carolina retail electric peak demand.

CHARACTER OF SERVICE

The applicable character of service is specific to the rate schedule that the customer receives service under.

RATE PER MONTH

The applicable rate per month shall be from the appropriate rate schedule as referenced in the availability section above. The monthly bill shall be determined as follows:

For electric service under a time-of-use rate schedule:

1. The basic facilities charge shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

2. Any demand charges shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

3. If a customer-generator's energy consumption exceeds the electricity provided by the customer-generator during a monthly billing period, the customer-generator shall be billed in kWh for the net electricity supplied by the Utility.

   If a customer-generator's energy generation exceeds the electricity provided by the Utility during a monthly billing period, the customer-generator shall be credited for the excess kWh generated during that billing period.

   Energy charges (or credits) shall be based on the rates in the applicable rate schedules as described in the availability section above. For on-peak energy, the customer's monthly usage amount in kilowatt-hours shall be reduced by the total of (a) any on-peak excess energy delivered to the Company in the current month plus (b) any accumulated on-peak excess energy balance remaining from prior months. Total on-peak energy in kilowatt-hours billed to customers shall never be less than zero. For off-peak energy, the customer's monthly usage shall be reduced by the total of (a) any off-peak excess energy delivered to the Company in the current month plus (b) any accumulated off-peak excess energy balance remaining from prior months plus (c) any accumulated on-peak excess energy balance from the current month or prior months that was not used to reduce on-peak usage. Total off-peak energy in kilowatt-hours billed to customers shall also never be less than zero. For any billing month during which excess energy exceeds the customer's usage in total, producing a net credit, the respective energy charges for the billing month shall be zero. Any excess energy credits shall carry forward on the following month's bill by first applying excess on-peak kWh against on-peak kWh charges and excess off-peak kWh against off-peak kWh charges, then applying any remaining on-peak kWh against any remaining off-peak kWh charges. Credits shall not offset the basic facilities charge or the demand charge for the applicable rate schedule.

4. Excess energy not used in the current billing month to reduce billed kWh usage shall be accumulated and used to reduce usage in future months. For all affected billing statements rendered during November billing cycles, any accumulated excess energy not used to reduce billed kWh usage shall be paid to the customer-generator at the Company's avoided cost, zeroing out the customer generator's account of excess energy. The avoided cost is the off-peak winter energy credit as approved in the Company's Rate PR-1, Small Power Production and Cogeneration schedule.

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For electric service under a standard, non time-of-use rate schedule:

1. The basic facilities charge shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

2. Any demand charges shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

3. If a customer-generator's energy consumption exceeds the electricity provided by the customer-generator during a monthly billing period, the customer-generator shall be billed in kWh for the net electricity supplied by the Utility.

   If a customer-generator's energy generation exceeds the electricity provided by the Utility during a monthly billing period, the customer-generator shall be credited for the excess kWh generated during that billing period.

   Energy charges (or credits) shall be based on the rates in the applicable rate schedules as described in the availability section above. For purposes of calculating monthly energy, the customer's usage shall be reduced by the total of (a) any excess energy delivered to the Company in the current month plus (b) any accumulated excess energy balance remaining from prior months. Total energy in kilowatt-hours billed to customers shall never be less than zero. For any billing month during which excess energy exceeds the customer's usage in total, producing a net credit, the respective energy charges for the billing month shall be zero. Credits shall not offset the basic facilities charge or the demand charge for the applicable rate schedule.

4. Excess energy not used in the current billing month to reduce billed kWh usage shall be accumulated and used to reduce usage in future months. For all affected billing statements rendered during November billing cycles, any accumulated excess energy not used to reduce billed kWh usage shall be paid to the customer-generator at the Company's avoided cost, zeroing out the customer generator's account of excess energy. The avoided cost is the off-peak winter energy credit as approved in the Company's Rate PR-1, Small Power Production and Cogeneration schedule.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge plus the demand charge, if any, as stated in the applicable rate.

DEFINITIONS

1. Customer-Generator means the owner, operator, lessee, or customer-generator lessee of an electric energy generation unit which:

   (A) generates electricity from a Renewable Energy Resource;
   (B) has an electrical generating system with a capacity of:
   (i) not more than the lesser of one thousand kilowatts (1,000 kW AC) or one hundred percent (100%) of contract demand if a non-residential customer; or
   (ii) not more than twenty kilowatts (20 kW AC) if a residential customer;
   (C) is located on a single premises owned, operated, leased, or otherwise controlled by the customer;
   (D) is interconnected and operates in parallel phase and synchronization with an electrical utility and complies with the applicable interconnection standards;
   (E) is intended primarily to offset part or all of the customer-generator's own electrical energy requirements; and
   (F) meets all applicable safety, performance, interconnection, and reliability standards established by the commission, the National Electrical Code, the National Electrical Safety Code, the Institute of Electrical and Electronics Engineers, Underwriters Laboratories, the federal Energy Regulatory Commission, and any local governing authorities.

2. Renewable Energy Resource means solar photovoltaic and solar thermal resources, wind resources, hydroelectric resources, geothermal resources, tidal and wave energy resources, recycling resources, hydrogen fuel derived from renewable resources, combined heat and power derived from renewable resources, and biomass resources.

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3. Retail Electric Service Rates shall mean Rates 1, 2, 3, 5, 6, 7, 8, 9 (metered), 11, 12, 13, 14, 16, 20, 21, 21A, 22, 23, 24, and 28.

4. Excess energy delivered to the Company shall be defined as energy produced by the customer's renewable energy generating facility that exceeds the energy delivered by the Company during a given time period. This excess energy shall be used to reduce energy delivered and billed by the Company during the current or a future month, as provided in the Rate Per Month section above.

5. The On-Peak and Off-Peak periods shall be defined in the applicable time-of-use rate schedules.

GENERAL PROVISIONS

1. To qualify for this rider, the customer must first qualify for and be served on one of the rate schedules as described in the availability section above. The customer must also meet all other qualifications as outlined in the availability section above.

2. All provisions of the applicable rate schedules described above including, but not limited to Billing Demand, Determination of On- and Off-Peak Hours, Adjustment for Fuel Costs, Demand Side Management Component, Pension Costs Component, Storm Damage Component, Sales and Franchise Tax, Payment Terms, and Special Provisions will apply to service supplied under this rider.

3. Customers electing service under this NEM Rider are eligible to remain on the Rider until December 31, 2025, or until such time as the customer elects to terminate service under the Rider, whichever occurs first. The rates set forth here are subject to Commission Order No. 2015-194 in Docket No. 2014-246-E entered under the terms of S.C. Code § 58-40-20(F)(4). Eligibility for this rate will terminate as set forth in Order No. 2015-194. The value of distributed energy resource generation shall be computed using the methodology contained in Commission Order No. 2015-194 in Docket No. 2014-246-E and updated annually coincident in time with the Company's filing in the fuel clause. The value for the period May 2018 – April 2019 is $0.03264 per kWh.

4. Service on this NEM Rider will be closed to new participants as of January 1, 2021, or after statutory caps described in S.C. Code Ann. § 58-39-130 have been reached, whichever occurs first.

5. When no contract demand level is available for a non-residential customer, connected load as determined by the Company shall be used as a proxy for contract demand when determining the capacity of the electrical generating system.

6. Customers who elect NEM service after January 1, 2021, will receive service in accordance with the NEM tariff in effect at the time at which the customer requests NEM service.

7. Customers served under this rider are not eligible for the Company's Small Power Production, Cogeneration Rate PR-1.

8. The customer must execute an application to interconnect generation and an interconnection agreement prior to receiving service under this rider.

9. The Company will retain ownership of Renewable Energy Credits ("RECs").

10. In the event the Company determines that it is necessary to increase the capacity of facilities beyond those required to serve the Customer's electrical requirement or to install a dedicated transformer or other equipment to protect the safety and adequacy of electric service provided to other customers, the Customer shall pay the estimated cost of the required transformer or other equipment above the estimated cost which Company would otherwise have normally incurred to serve the Customer's electrical requirement, in advance of receiving service under this Rider.

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RIDER TO RETAIL RATES

NET ENERGY METERING FOR
RENEWABLE ENERGY FACILITIES ("NEM")
(Page 4 of 4)

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.

METERING REQUIREMENTS

Customer must furnish, install, own, and maintain a meter socket to measure 100% of the Customer's generator output and that is connected on the Customer's side of the delivery point. Company will furnish, install, own, and maintain a generation meter. Company will also furnish, install, own and maintain a bi-directional billing meter to measure the kWh delivered from Company to Customer and to measure kWh received from Customer by Company. The billing meter will be configured for demand and/or time-of-use measurement as required by the applicable rate. All metering shall be at a location that is approved by the Company. At Company's sole option, the generator meter requirement may be waived for customers served under a net metering rider on or before December 31, 2015.

TERM OF CONTRACT

Contracts shall be for a period not to exceed the term of the contract under which the customer currently receives electric service. There shall be a separate contract for each meter at each location.

GENERAL TERMS AND CONDITIONS

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

Exhibit No. __ (JML-1)

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

(MW)

	YEAR	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
2	EE/Renewables Impact	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
3	Gross Territorial Peak	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5636	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																															
4	Existing	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	6212	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6275	6491
5	Existing Solar	58.73	0	96.36	0	161.6	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0
6	Demand Response	274	222	275	223	276	324	277	325	278	326	280	327	281	328	282	329	283	330	285	331	286	332	287	333	288	333	290	334	291	335
	Additions:																														
7	Solar Plant	37.63	0	65.21	0	141.2	0																								
8	Peaking/Intermediate																												93		
9	Baseload		504										540	-30																	
10	Retirements			-85		-25																									
11	Total System Capacity	5648	6190	6134	6106	6251	6182	6252	6183	6253	6184	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6826
12	Firm Annual Purchase	300			50		25		100		150																				
13	Total Production Capability	5948	6190	6134	6156	6251	6207	6252	6283	6253	6334	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6826
Reserves																															
14	Margin (L13-L3)	871.4	1166	1023	1085	1071	1090	998.8	1097	893.8	1106	814.8	1468	1265	1427	1198	1380	1132	1337	1075	1297	1021	1257	970.8	1221	925.8	1179	875.8	1231	920.8	1189
15	% Reserve Margin (L14/L3)	17.2%	23.2%	20.0%	21.4%	20.7%	21.3%	19.0%	21.2%	16.7%	21.2%	15.0%	27.9%	23.0%	26.9%	21.5%	25.8%	20.1%	24.8%	18.9%	23.9%	17.8%	23.0%	16.7%	22.2%	15.8%	21.2%	14.8%	22.0%	15.5%	21.1%

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2017 Reserve Margin Study

SCE&G®
A SCANA COMPANY

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Summary

Introduction

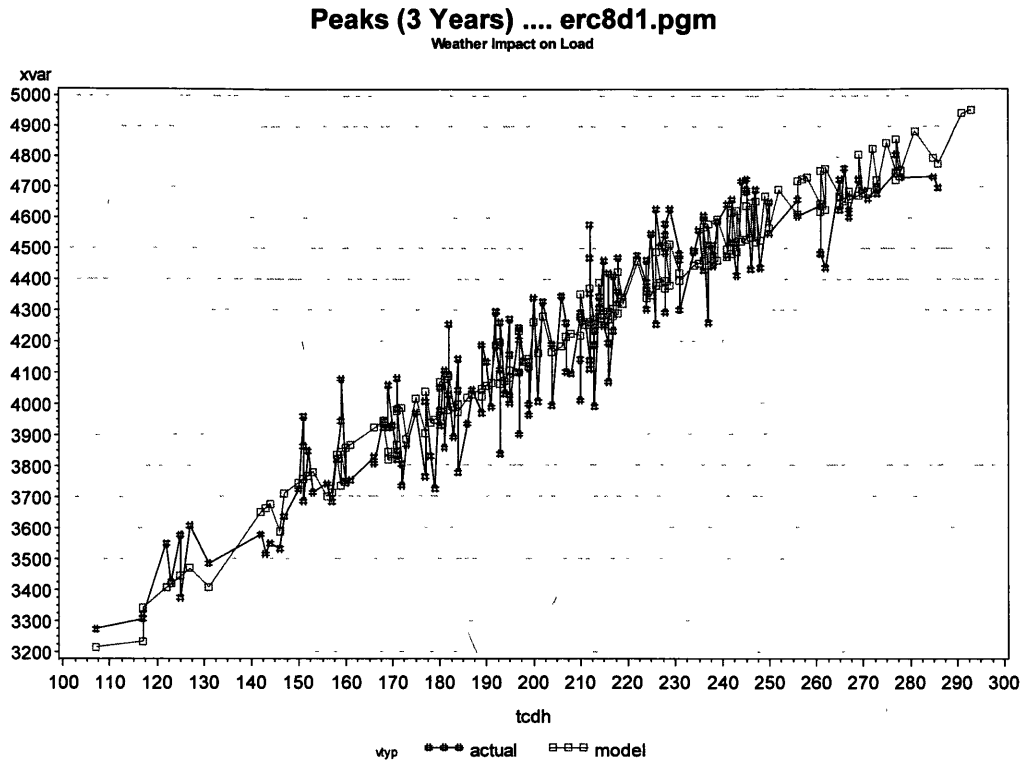
All electric utilities require supply reserves to mitigate the risk of not being able to serve their load requirement because of demand-side related risk and supply-side related risk. Demand-side risk results from uncertainty in the level of demand which can increase because of abnormal weather or other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

Reserve Margin Components
1. VACAR Operating Reserves
2. Demand-Side Risk
3. Supply-Side Risk

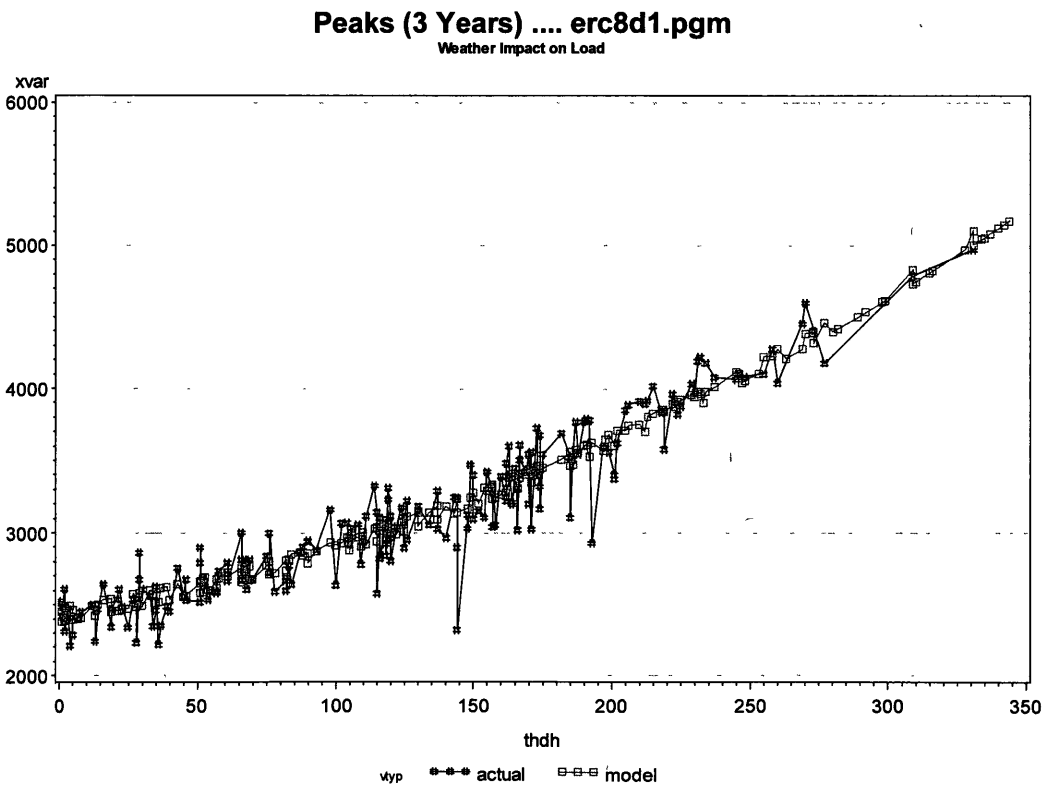
In determining its required reserve margin, SCE&G finds it necessary to analyze the need separately for the cooling season and the heating season. Additionally, within each season it is necessary to distinguish between a peaking need and a base need. There are at least two reasons for this dichotomy.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

Demand-Side Risk

The major source of demand-side risk derives from abnormal weather. To quantify the impact of weather on daily peak demands, two regression equations were estimated: one for summer relating daily summer peak demands to cooling degree hours and one for winter relating daily winter peak demands to heating degree hours. Three years of data were combined using the months of June, July and August for the summer model and December, January and February for the winter model. The following chart compares the summer regression model to the actual daily peak demands. The estimated regression equations and related statistics are included as appendices.



The following chart compares the winter regression model to the actual daily peak demands.



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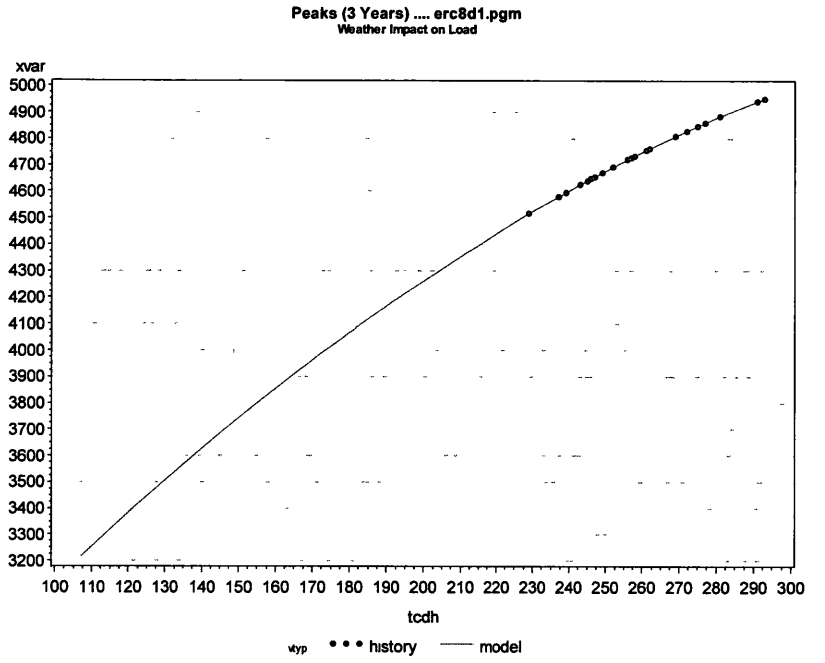
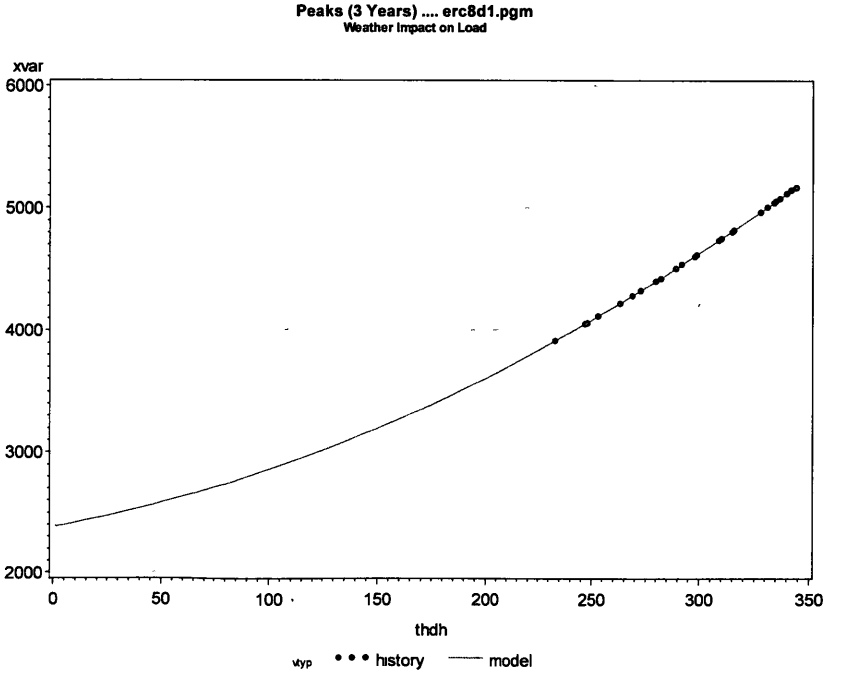
The next step was to use these regression equations to estimate what the peak demand would be on SCE&G's system today given the weather that occurred on historical peak days since 1991. The following chart displays the resulting summer peak demands and where they fall along the regression line.



The following is the similar graph for winter.



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The following table shows the maximum peak demand that would result from the most extreme weather since 1991. The table also shows the average peak demand which represents the peak demand expected under normal or average weather conditions today. Finally, the table shows the maximum deviation from normal that could occur on SCE&G's system due to abnormal weather.

Table 1

MW Peak Demand				
Weather	**Maximum**	**Normal**	**Deviation**	**%Deviation**
Summer	**4952**	**4744**	**208**	**4.4%**
Winter	**5172**	**4630**	**542**	**11.7%**

By calculating the mean peak demand values and then taking deviations about that mean, a probability distribution of weather related deviations can be calculated for summer and winter. The following chart shows these probability distributions. The top distribution for the summer period is similar to a normal or bell-shaped probability distribution while the bottom chart representing the weather risk in winter is more spread out and similar to a uniform probability distribution.

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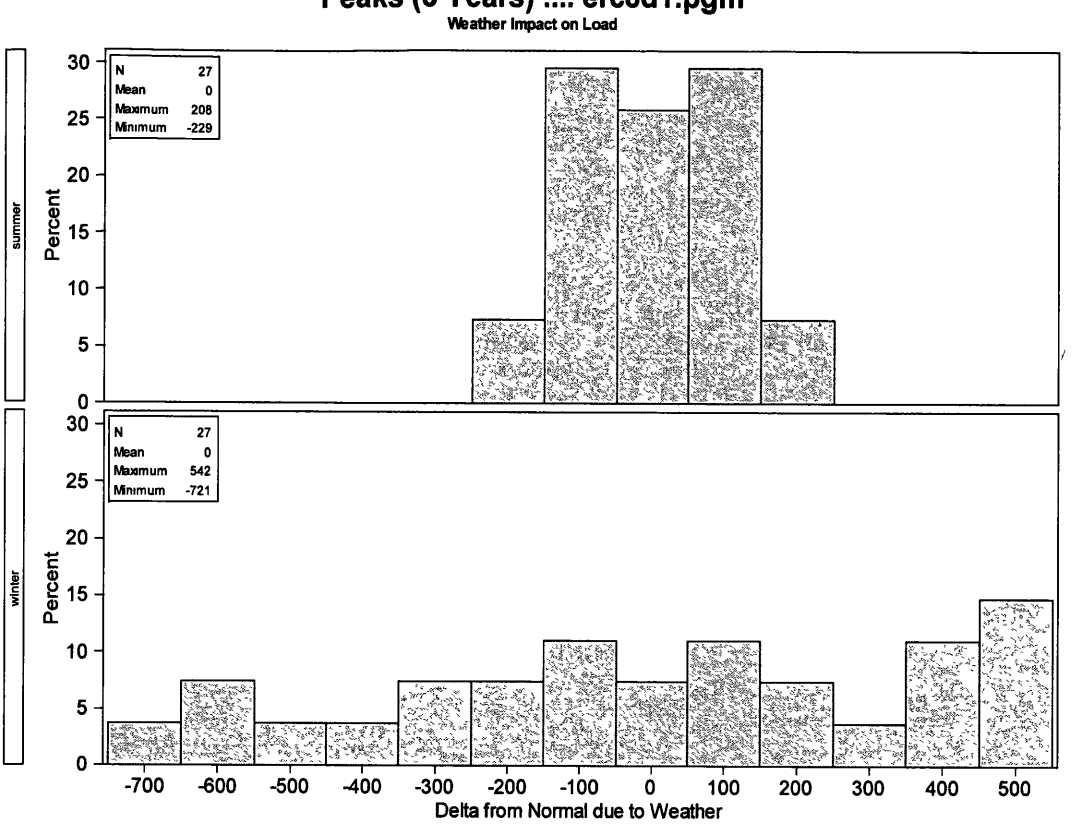

The following table summarizes the risk of higher peak demands based on these distributions.

Table 2

MW Weather Deviations By Percentile				
Percentile	**75%**	**90%**	**95%**	**100%**
Summer	**115**	**139**	**197**	**208**
Winter	**376**	**491**	**516**	**542**

Clearly, winter weather poses a greater demand-side reliability risk than summer since the maximum deviation from a normal weather forecast can reach as much as 542 MWs while in summer the maximum deviation is closer to 208 MWs.

Supply-Side Risk

To quantify the supply-side risk, the forced outage history of SCE&G's generating units was analyzed. By calculating the number of MWs of generation that was forced out or de-rated on each day

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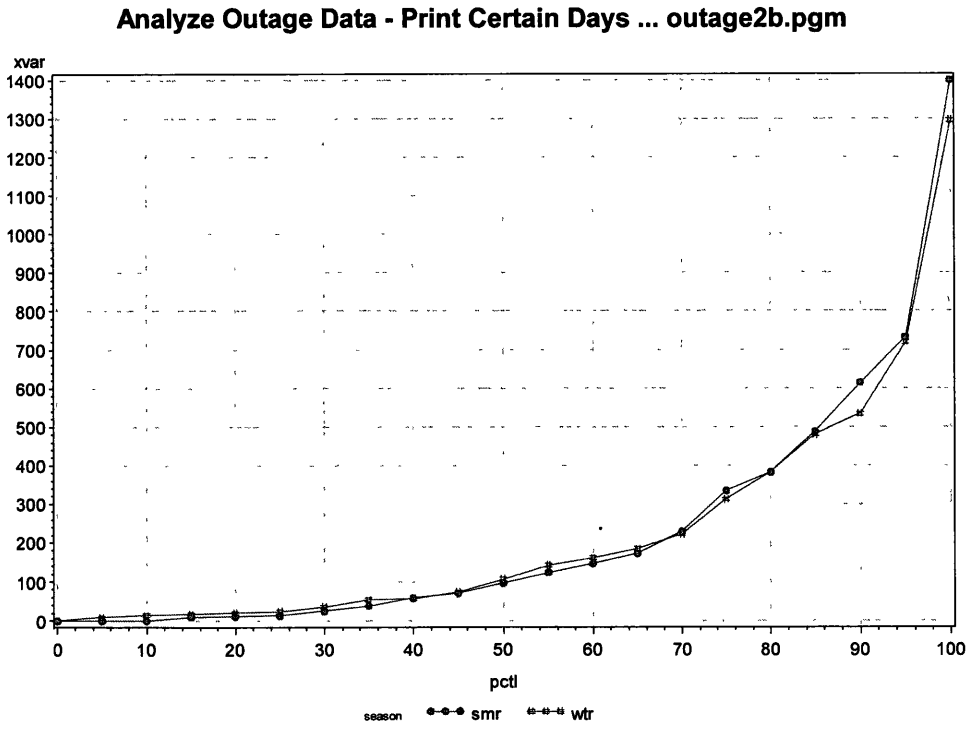
of the summer and winter, a distribution of outage was developed for the summer season and for the winter season. For summer, the daily outages during the months of June, July and August were studied for the years 2010-2016. For winter, the months of December, January and February were used. The resulting number of days used for summer was 644 and for winter 632. Below is a table summarizing each of these distributions.

Table 3

MWs Forced Out By Percentile						
Percentile	50%	60%	70%	80%	90%	100%
Summer	97	147	230	382	614	1400
Winter	108	162	224	382	534	1296

The following is the distribution in graphical form showing the accumulated MWs out by the percentile in the probability distribution.



To maintain reliability and replace the loss of generating capacity up to 70% of the days in summer, SCE&G estimates that it needs about 230 MWs of reserve capacity. For the winter season, 224 MWs of generating capacity is enough to back stand 70% of the days.

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Summary: Reserve Capacity for Summer and Winter Peak Periods

To calculate the required reserve margins for summer and winter peak periods, SCE&G used the maximum deviation from normal estimated in the demand-side risk analysis and the 70% cutoff value from the outage distributions developed for the summer and winter seasons. The following table summarizes the results.

Table 4

Reserve Margin for Summer and Winter Peak Periods		
	Summer	Winter
VACAR Operating	200	200
Demand-Side Risk	208	542
Supply-Side Risk	230	224
Total Reserve MWs	638	966
Normal Peak Demand	4744	4630
Reserve Margin %	13.4%	20.9%
Reserve Margin Policy	14%	21%

SCE&G's reserve margin policy is to have a level of capacity reserves at least as great as 14% of the normal weather summer peak forecast for the summer season and 21% of the normal weather winter peak forecast for the winter season.

Reserve Capacity Needed to Operate the System Reliably Throughout the Year

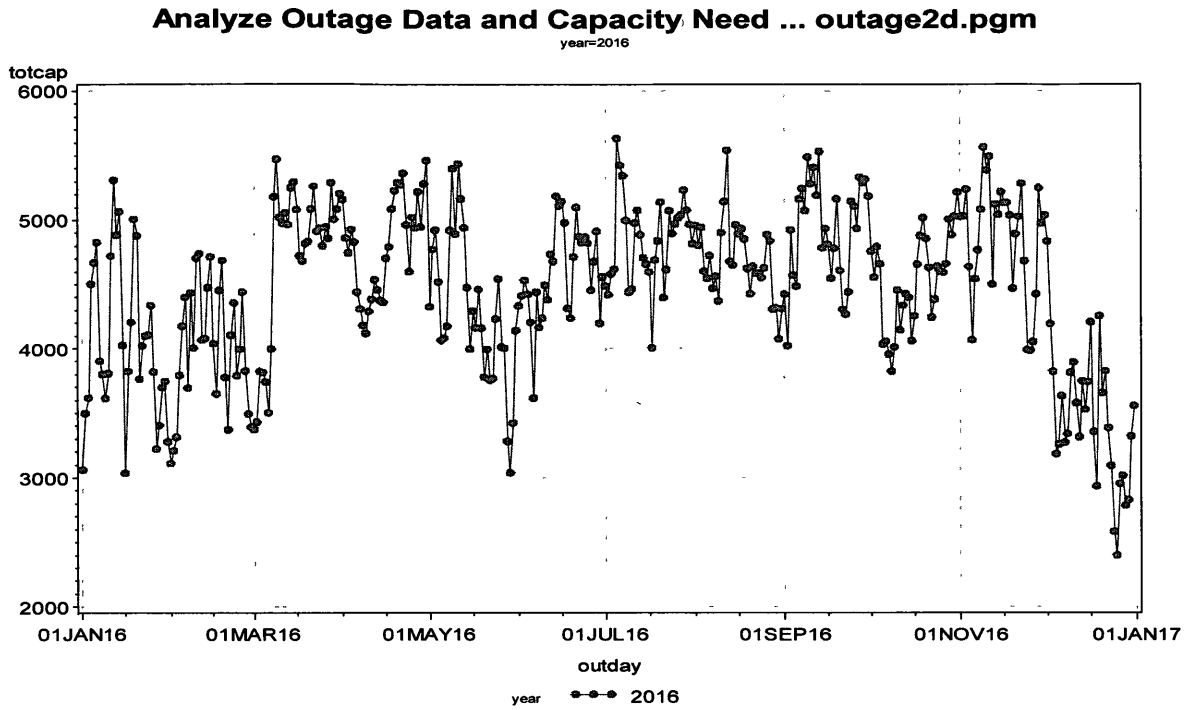
In addition to the reserves needed to address risk during the summer and winter peak periods, SCE&G also needs reserve capacity to operate the system throughout the year not only to meet the load but also cover both scheduled and un-scheduled generating unit outages. To quantify this need SCE&G analyzed its forced and scheduled outages since 2010 and determined the capacity needed each day throughout the year. The basic formula relating available capacity and system need is the following.

Total Capacity — MWs Forced Out — MWs Scheduled Out = Peak Load + Residual Operating Reserves

By rearranging terms, the daily capacity need can be calculated with this formula.

Total Daily Capacity Needed = Daily Peak Load + MWs Forced Out + MWs Scheduled Out + Desired Daily Reserves

Setting the "Desired Daily Reserves" equal to the VACAR Operating Reserve requirement of 200 MWs, SCE&G can calculate its daily capacity need by using its historical experience with scheduled and forced outages. Following is a graph of the daily capacity need in 2016.



Below is the chart for 2014 which was the year when an arctic blast of cold air hit the southeast on January 7, 2014. The spike in capacity needed above 6000 MWs was principally caused by the forced outage of Williams Station on that day.

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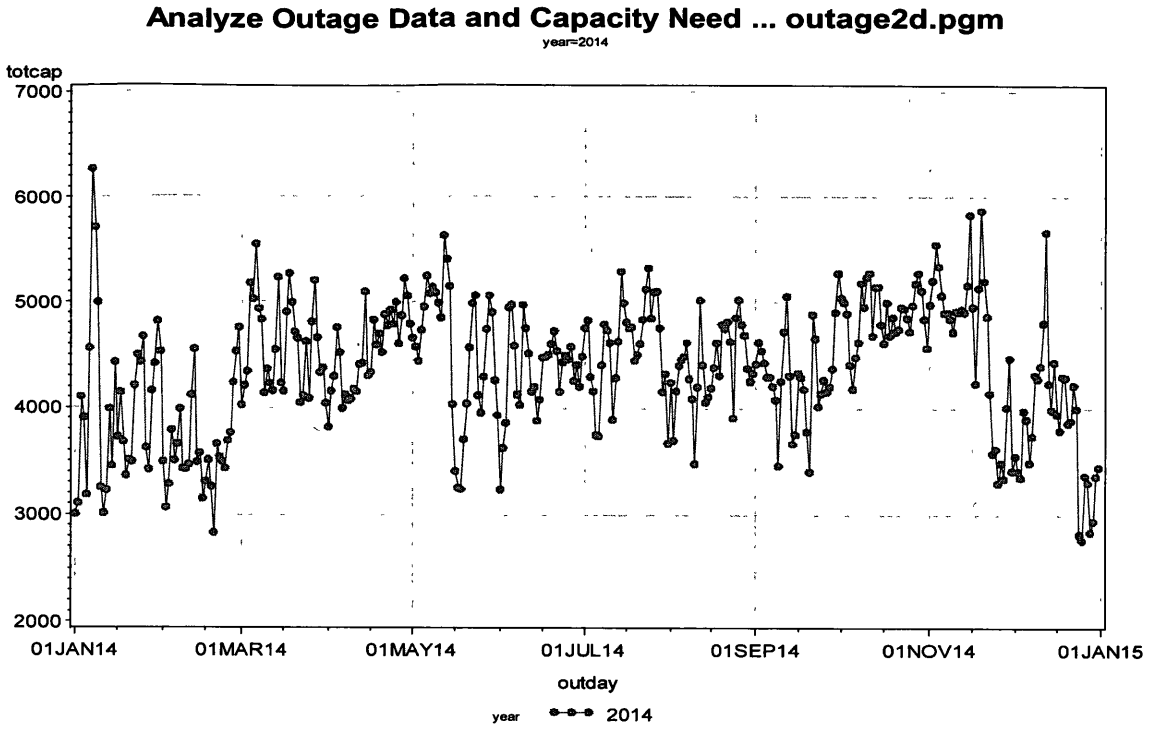

The daily capacity need for each year from 2010 to 2016 was calculated by season. Each year and season was considered a separate distribution of daily need and from each distribution the 95th, 96th and 97th percentiles were extracted. These percentiles represented the amount of capacity needed to serve 95%, 96% and 97% of the days in the distribution respectively. The peak days in the distribution, defined as the top 10 to 20 days of highest capacity need, correspond to a demarcation at the 95th and 97th percentile i.e. 10/365 is about 3% and 20/365 is about 5% of the days in the year or stated differently 355/365 is about 97% and 345/365 is about 95%. The individual years and seasons are shown in Appendix C. The table below shows the average of these percentiles from the seven years studied. For example, in the summer, SCE&G needs about 5,121 MWs of capacity to serve 95% of the days in the summer period while 5,312 MWs is needed to serve 97% of the days in the winter period. Since this level of capacity is needed to serve most of the days of the year, SCE&G considers this a base level of capacity.

Table 5

Distribution of Daily Capacity Need at Certain Percentiles (MWs)				
Percentile	**95%**	**96%**	**97%**	**100%**
Summer	**5256**	**5306**	**5355**	**5705**
Winter	**5121**	**5184**	**5312**	**5731**

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In the following table, the base level of capacity is expressed as a percentage of the average maximum customer load occurring in the particular season. Averaging the percentages for the 95th and the 97th percentile yields 12.25% for summer and 14.05% for winter. SCE&G therefore establishes base reserve capacity need in summer of 12% of summer peak demand and in winter, 14% of winter peak demand.

Table 6

Daily Capacity Need Percentiles as Percent of Peak Load					
Percentile	**95%**	**96%**	**97%**	**100%**	**Peak Load**
Summer	**11.2**	**12.2**	**13.3**	**20.7**	**4729**
Winter	**11.9**	**13.3**	**16.2**	**25.3**	**4600**

Conclusion

For the summer months which include May through October, SCE&G requires base reserves in the amount of 12% of the summer peak load to operate the system reliably and 14% of summer peak load during the peak load periods. For the winter months of November through April, SCE&G requires 14% of the winter peak load forecast in base reserves to operate the system reliably and 21% for the peak load periods. The following table summarizes SCE&G's reserve margin policy.

Table 7

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

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Appendix A: Regression Equation for Daily Summer Peak Demand against Cooling Degree Hours

Peaks (3 Years) erc8d1.pgm
Weather Impact on Load

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

Number of Observations Read	297
Number of Observations Used	270
Number of Observations with Missing Values	27

Weight: wgts Weight

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	29969188	4994865	443.08	<.0001
Error	263	2964842	11273		
Corrected Total	269	32934029			

Root MSE	106.17515	R-Square	0.9100
Dependent Mean	4139.00979	Adj R-Sq	0.9079
Coeff Var	2.56523		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	1	4298.41935	14.09494	304.96	<.0001	0
ihol	1	-276.97847	62.00124	-4.47	<.0001	1.01145
wkend	1	-248.70374	14.53597	-17.11	<.0001	1.02044
cdh	1	9.17900	0.19527	47.01	<.0001	1.25657
cdh2	1	-2.06140	0.38020	-5.42	<.0001	1.01827
yrlag1	1	-134.68185	17.83707	-7.55	<.0001	1.66784
yrlag2	1	-109.94246	16.73247	-6.57	<.0001	1.47090

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Appendix B: Regression Equation for Daily Winter Peak Demand against Heating Degree Hours

Peaks (3 Years) erc8d1.pgm
Weather Impact on Load

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

Number of Observations Read	345
Number of Observations Used	318
Number of Observations with Missing Values	27

Weight: wgts Weight

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	93931187	15655198	790.70	<.0001
Error	311	6157566	19799		
Corrected Total	317	100088753			

Root MSE	140.70980	R-Square	0.9385
Dependent Mean	3002.63669	Adj R-Sq	0.9373
Coeff Var	4.68621		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	1	2908.82737	16.76640	173.49	<.0001	0
ihol	1	-458.93137	46.27237	-9.92	<.0001	1.02568
wkend	1	-396.77172	17.77649	-22.32	<.0001	1.02971
hdh	1	6.35945	0.12564	50.62	<.0001	1.35070
hdh2	1	1.39994	0.14226	9.84	<.0001	1.28290
yrlag1	1	67.80463	20.16022	3.36	0.0009	1.35901
yrlag2	1	95.00406	19.81164	4.80	<.0001	1.40634

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Appendix C: Daily Capacity Need by Year and Season for Certain Percentiles in the Distribution

Analyze Outage Data and Capacity Need ... outage2d.pgm

seas	wyear	ndys	mxcap	mxload	cap95	cap96	cap97	mxresm	mxresm 95	mxresm 96	mxresm 97
summer	2010.0	184.0	5778.0	4735.0	5268.0	5322.0	5415.0	22.0	11.3	12.4	14.4
	2011.0	184.0	5691.0	4885.0	5412.0	5462.0	5490.0	16.5	10.8	11.8	12.4
	2012.0	184.0	6179.5	4761.0	5222.5	5251.5	5297.5	29.8	9.7	10.3	11.3
	2013.0	184.0	5643.0	4574.0	5262.0	5304.0	5390.0	23.4	15.0	16.0	17.8
	2014.0	184.0	5632.5	4594.0	5187.0	5249.5	5280.0	22.6	12.9	14.3	14.9
	2015.0	184.0	5382.5	4750.0	5111.5	5163.5	5195.5	13.3	7.6	8.7	9.4
	2016.0	184.0	5628.5	4807.0	5326.0	5391.5	5419.5	17.1	10.8	12.2	12.7
summer		184.0	5705.0	4729.4	5255.6	5306.3	5355.4	20.7	11.2	12.2	13.3
winter	2010.0	181.0	5285.0	4718.0	5008.0	5049.0	5102.0	12.0	6.1	7.0	8.1
	2011.0	181.0	5638.5	4868.0	5014.0	5038.0	5130.0	15.8	3.0	3.5	5.4
	2012.0	182.0	5818.0	4397.0	5314.0	5377.0	5420.0	32.3	20.9	22.3	23.3
	2013.0	181.0	5944.0	3984.0	4914.0	5075.0	5376.0	49.2	23.3	27.4	34.9
	2014.0	181.0	6269.0	4853.0	5233.0	5344.0	5552.0	29.2	7.8	10.1	14.4
	2015.0	181.0	5598.0	4970.0	5081.0	5115.0	5246.5	12.6	2.2	2.9	5.6
	2016.0	182.0	5561.0	4409.0	5284.0	5291.0	5357.0	26.1	19.8	20.0	21.5
winter		181.3	5730.5	4599.9	5121.1	5184.1	5311.9	25.3	11.9	13.3	16.2

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Avoided Energy Cost Methods Study for Solar QFs

Summary: Because of the significant amount of solar QFs either currently generating on SCE&G's system or under a signed PPA to generate in the near future, SCE&G found it necessary to change how its avoided energy costs are calculated. This study shows that it is no longer feasible to use the traditional methodology of using a 100 MW power purchase in every hour of the year but instead that a a 100 MW solar sourced power purchase should be used to calculate avoided energy costs.

Introduction: SCE&G designed this study to measure the difference in estimated avoided costs when using its traditional methodology versus using a solar profile. Avoided energy costs are defined as those costs that would not be incurred, i.e., that can be avoided, by the purchase of energy from a QF. To calculate these avoided costs, SCE&G uses its PROSYM model to estimate the production costs of a base case and then a change case. In its traditional methodology, SCE&G created the change case by assuming a 100 MW round-the-clock purchase in every hour of the year and then collected the change in production costs into four time periods: 2 seasons X 2 daily periods. QFs would then be paid based on how much energy they generated in each period. For this study, SCE&G will also calculate the avoided costs that result when the 100 MW QF purchase follows the profile of a solar PV generator. Two solar profiles were chosen for the study to see how the results differ with the profile. Since the results of a PROSYM run can vary because of random plant outages, PROSYM was run 10 times in each case using a different random number seed and the averages of the results from these 10 runs were used as the basis of the comparison.

Operational Issues (The "Duck Curve"): As more and more solar QFs are added to the system, the graph of the changing system load begins to take the shape of a duck, thereby creating the moniker of the "Duck Curve". See the following graph. This graph can be used to demonstrate the increasing difficulty facing the rest of the generating fleet as more and more solar comes online. On this particular day January 19, 2017, the morning peak was over 2600 MWs and the evening peak a little higher, just under 2700 MWs. As more solar is added to the system, the belly of the duck grows and the system begins to face a lower and lower minimum load falling between the morning and evening peak. One problem this presents is called a "low load" problem where the load gets so low that some generators, perhaps a coal plant, must be taken off-line because it can't operate at an output below a certain minimum level. Even

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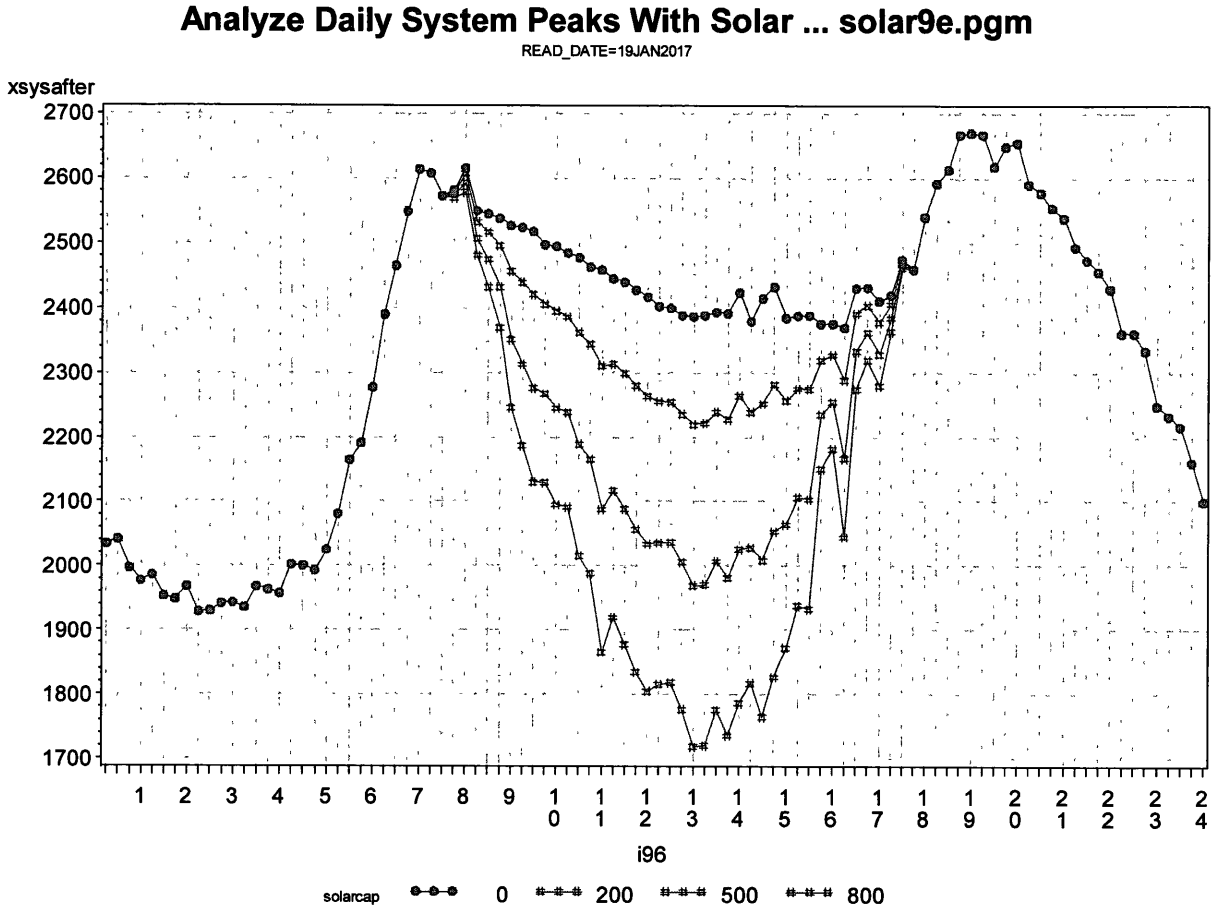
if plants can remain operational at a lower level of output, the lower level will not be the most efficient operating point and the cost of their output will be higher than it would otherwise be. The other operational issue is the ramping rate. With more and more solar generation, the ramp rate down in the morning and the ramp rate up in the evening can be difficult to follow.



Fortunately, SCE&G has the Fairfield Pumped Storage unit which might alleviate some of the low load problem by pumping for a few hours. This unit is very flexible and can help with the ramping issue as well. Of course, while SCE&G may be able to serve the load under these conditions, the cost of serving the load will increase. This is the basic reason that SCE&G believes to accurately estimate its avoided costs for future solar QFs, it must now use a power purchase profile that is based on a solar generator.

The Results: The PROSYM model was run 40 times with each run simulating the system dispatch for a base case and a change case and calculating the difference in production costs over the 15-year planning horizon. In each case the avoided energy costs for the 15 years were levelized so a single number could be compared. The following table summarizes these results.

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Table 1

Avoided Energy Cost Methods Study: Summary Results			
Seed	8760 Profile	SC Solar Profile	NC Solar Profile
1	35.41	31.26	30.48
2	34.45	30.46	29.53
3	34.87	29.83	30.32
4	34.84	30.01	32.10
5	35.01	30.19	31.24
6	35.36	32.31	30.49
7	34.78	29.43	30.56
8	35.03	28.62	32.08
9	35.91	31.67	30.44
10	34.67	27.98	31.33
Avg	**35.03**	**30.18**	**30.86**
Max	35.91	32.31	32.10
Min	34.45	27.98	29.53
Diff	1.46	4.33	2.57

The avoided energy cost based on the SC solar profile is $30.18 per MWH while using the NC solar profile yields $30.86 per MWH. The following table shows the calculation of avoided costs when using the traditional methodology to calculate avoided costs by time period and then pay the SC solar profile based on how much energy is generated in each period.

Table 2

	Peak Season Peak Hours	**Peak Season Off-Peak ours**	**Off-Peak Season Peak Hours**	**Off-Peak Season Off-Peak Hours**
Avoided Costs ($/MWH)	$36.27	$32.57	$35.82	$34.44
SC Solar Weights (kWh/kW)	470	287	672	682
Resulting Weighted-Average Avoided Cost Using SC Solar Weights				$35.03

Avoided Costs ($/MWH)	$36.27	$32.57	$35.82	$34.44
NC Solar Weights (kWh/kW)	496	299	580	612
Resulting Weighted-Average Avoided Cost Using NC Solar Weights				$35.02

The difference in results for avoided energy costs using the SC solar weights is an indication of the additional production costs resulting from the operational issues caused by increased amounts of solar power on the system. Using the PROSYM model the estimated increase in cost is about $4.85 per MWH ($35.03 - $30.18). Since the PROSYM model commits and dispatches units with 100% foreknowledge, this estimate must understate the true increase in operational costs.

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Appendix

Results for Round-the-clock 8760 Profile

Random Seed 1

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	30.57	25.16	35.41	34.78
2019	30.10	26.12	33.88	24.45
2020	29.65	31.17	37.00	31.54
2021	36.84	23.88	33.37	36.28
2022	33.50	31.24	34.72	33.71
2023	30.28	36.26	39.70	37.30
2024	32.08	33.98	28.46	32.77
2025	32.27	28.70	31.57	27.83
2026	32.77	29.76	32.80	32.37
2027	38.39	29.39	32.47	38.60
2028	38.49	29.91	36.18	33.70
2029	39.48	36.12	38.28	37.83
2030	46.00	36.57	40.97	38.93
2031	47.54	40.14	43.03	39.16
2032	48.62	42.91	47.31	41.74
Levelized	35.97	31.94	36.86	35.06

Random Seed 2

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.34	24.85	27.75	31.25
2019	27.93	27.19	27.20	30.17
2020	34.04	26.07	31.05	31.10
2021	39.64	28.67	30.87	32.46
2022	29.22	24.64	33.72	30.52
2023	34.08	30.59	34.90	39.76
2024	27.00	37.16	26.74	32.45
2025	38.09	29.10	33.94	31.13
2026	29.82	37.92	32.22	35.28
2027	31.72	33.73	34.67	35.91
2028	38.26	35.76	36.33	34.03
2029	38.68	36.53	37.73	34.80
2030	42.68	34.32	43.28	38.22
2031	49.58	40.17	46.40	37.87
2032	44.37	41.08	47.82	40.89
Levelized	35.42	32.11	34.44	34.78

Random Seed 3

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	28.79	25.44	29.56	29.06
2019	29.37	25.23	28.07	27.43
2020	26.34	29.93	29.21	28.45
2021	33.94	26.09	33.89	31.68
2022	40.22	30.60	31.86	31.44
2023	42.69	33.65	38.26	34.29
2024	34.79	31.76	34.96	29.46
2025	37.95	35.16	37.89	27.81
2026	39.11	36.39	34.52	37.33
2027	39.22	32.34	39.17	31.81
2028	41.09	30.99	32.45	37.84
2029	43.96	32.40	40.35	34.28
2030	38.55	36.96	44.10	39.31
2031	44.97	37.61	43.07	42.23
2032	45.08	39.79	42.02	39.15
Levelized	37.37	32.21	35.75	33.40

Random Seed 4

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.11	27.01	28.49	28.66
2019	33.26	28.77	33.06	31.21
2020	28.81	28.66	29.78	30.63
2021	31.61	31.73	32.50	30.39
2022	30.13	31.67	30.81	30.66
2023	41.01	30.74	37.49	38.76
2024	40.52	30.72	42.18	30.37
2025	29.99	33.08	34.35	32.13
2026	36.03	31.26	34.23	32.60
2027	42.63	31.37	30.70	33.57
2028	39.98	32.01	33.64	33.67
2029	37.74	33.47	35.69	37.57
2030	42.44	37.96	43.41	35.49
2031	49.11	34.35	39.85	38.81
2032	43.34	42.28	38.45	44.66
Levelized	36.70	32.53	35.27	34.11

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Random Seed 5

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.64	28.56	35.23	32.30
2019	24.55	27.08	28.21	27.81
2020	29.12	31.68	28.23	28.93
2021	31.75	27.17	33.17	33.56
2022	31.61	30.54	35.97	34.21
2023	38.70	30.72	41.84	31.99
2024	30.71	30.29	30.43	26.19
2025	40.04	33.09	28.39	32.81
2026	42.05	33.85	36.57	34.29
2027	31.68	36.10	36.08	39.67
2028	38.46	36.99	37.36	32.51
2029	37.34	34.84	45.20	39.50
2030	41.89	38.12	42.83	35.71
2031	36.40	38.75	46.66	37.39
2032	54.30	38.67	43.70	41.92
Levelized	35.35	33.08	36.50	34.13

Random Seed 6

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.47	27.39	31.01	30.46
2019	31.03	26.40	37.74	27.87
2020	26.60	28.21	35.50	36.53
2021	31.25	30.07	25.95	33.84
2022	35.31	35.79	34.06	35.26
2023	33.41	31.66	33.61	33.15
2024	41.47	25.60	35.22	30.95
2025	25.29	34.05	35.06	28.47
2026	36.61	34.01	40.18	31.05
2027	36.35	33.71	41.27	35.35
2028	39.90	31.69	32.01	38.50
2029	47.37	32.33	42.61	37.27
2030	43.26	36.28	43.27	38.42
2031	42.94	38.15	37.98	37.57
2032	50.91	38.30	42.86	38.98
Levelized	36.09	32.40	36.80	34.69

Random Seed 7

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	27.98	25.70	30.96	29.25
2019	33.92	30.45	32.10	30.59
2020	29.32	30.64	29.71	28.42
2021	33.91	33.64	32.28	27.80
2022	37.47	26.64	33.17	31.81
2023	37.36	28.93	34.57	34.66
2024	27.51	35.27	33.98	36.21
2025	39.61	34.84	35.80	32.34
2026	39.13	31.20	35.46	38.68
2027	33.37	34.13	36.42	35.12
2028	39.67	34.35	26.73	36.02
2029	39.83	33.39	31.68	36.71
2030	37.60	38.98	36.81	36.32
2031	51.28	33.32	44.47	37.70
2032	48.31	39.93	42.47	38.22
Levelized	36.75	32.98	34.81	34.16

Random Seed 8

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	30.44	26.40	32.46	33.22
2019	27.76	28.00	37.48	27.42
2020	29.70	29.17	32.68	30.77
2021	32.13	27.26	30.85	28.94
2022	41.52	26.05	32.46	30.38
2023	35.03	34.77	33.35	30.76
2024	33.03	31.70	35.27	32.40
2025	29.07	31.58	39.93	28.45
2026	33.97	31.85	33.70	33.66
2027	37.57	32.90	38.79	38.70
2028	42.55	37.92	34.72	34.76
2029	40.66	35.16	41.63	38.69
2030	40.60	37.43	42.79	36.08
2031	47.30	36.53	36.40	39.20
2032	48.14	37.43	40.42	42.39
Levelized	36.20	32.24	36.66	33.80

Random Seed 9

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	31.01	26.38	32.74	34.19
2019	33.76	24.04	33.49	29.09
2020	31.08	34.47	34.30	31.00
2021	32.18	28.91	36.15	29.84
2022	38.35	29.65	35.18	34.07
2023	37.29	31.21	34.45	41.28
2024	34.39	29.58	32.28	33.37
2025	36.40	30.09	34.69	31.66
2026	43.88	29.51	34.29	36.33
2027	37.03	36.95	37.57	35.98
2028	34.56	37.52	34.81	35.27
2029	41.24	35.80	38.53	31.73
2030	43.60	35.19	41.09	38.50
2031	42.21	35.59	44.78	41.86
2032	44.64	39.21	42.54	42.32
Levelized	37.47	32.29	36.83	35.47

Random Seed 10

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	28.03	25.34	28.16	30.22
2019	27.74	28.66	30.93	28.67
2020	30.54	30.31	34.52	28.00
2021	37.30	31.68	28.45	29.01
2022	34.19	34.75	36.71	35.98
2023	35.78	35.42	36.05	38.65
2024	35.43	33.41	30.17	30.11
2025	34.54	31.62	25.48	32.86
2026	28.10	32.78	38.29	36.08
2027	40.55	34.17	38.28	36.56
2028	30.37	36.24	28.93	36.97
2029	38.44	41.58	37.14	36.59
2030	44.00	37.01	42.73	37.85
2031	46.04	37.78	33.92	44.08
2032	41.45	37.56	38.70	42.58
Levelized	35.38	33.95	34.30	34.84

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SUMMARY TABLE

Leeds Profile	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
Seed1	35.97	31.94	36.86	35.06
Seed2	35.42	32.11	34.44	34.78
Seed3	37.37	32.21	35.75	33.40
Seed4	36.70	32.53	35.27	34.11
Seed5	35.35	33.08	36.50	34.13
Seed6	36.09	32.40	36.80	34.69
Seed7	36.75	32.98	34.81	34.16
Seed8	36.20	32.24	36.66	33.80
Seed9	37.47	32.29	36.83	35.47
Seed10	35.38	33.95	34.30	34.84
Average	36.27	32.57	35.82	34.44
Solar Weights	470	287	672	682
Levelized Avoided Solar Cost				35.03

Solar Weights	496	299	580	612
Levelized Avoided Solar Cost				35.02

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RESULTS FOR TWO SOLAR PROFILE CASES

SC Solar Profile										
Year	Seed1	Seed2	Seed3	Seed4	Seed5	Seed6	Seed7	Seed8	Seed9	Seed10
2018	30.32	32.46	35.70	30.85	31.73	28.96	22.23	31.05	29.76	25.95
2019	33.18	30.31	23.18	28.04	30.53	32.59	32.42	27.08	29.04	26.92
2020	24.00	24.40	25.46	24.11	23.80	26.75	28.07	27.68	26.76	19.02
2021	27.74	24.28	29.66	27.03	27.94	28.11	24.82	25.49	25.48	27.85
2022	26.35	28.09	25.24	24.52	28.21	25.91	26.37	18.45	26.55	22.62
2023	28.31	31.90	24.87	32.56	26.64	34.32	27.06	19.08	38.74	24.40
2024	27.39	29.27	24.40	25.63	29.51	30.73	22.27	23.46	27.84	24.17
2025	30.70	25.17	27.50	29.85	22.18	27.49	29.75	28.04	31.45	26.12
2026	30.71	31.42	30.12	28.69	25.50	38.18	30.60	30.97	30.67	27.23
2027	34.79	30.89	24.35	28.95	33.43	35.11	31.27	30.29	33.15	31.18
2028	27.49	31.95	32.16	30.98	34.68	32.03	33.86	28.87	34.72	26.07
2029	36.73	30.78	33.97	27.09	29.97	39.09	31.00	29.03	31.22	34.70
2030	35.34	26.77	31.34	31.43	31.45	28.64	28.05	36.73	31.19	36.48
2031	31.06	38.70	35.60	35.55	28.27	32.22	35.52	33.98	33.85	31.53
2032	38.87	28.85	37.40	38.39	39.70	37.75	33.62	35.60	39.01	36.93
Levelized	31.26	30.46	29.83	30.01	30.19	32.31	29.43	28.62	31.67	27.98
			Average Levelized Avoided Cost Solar				**30.18**			

NC Solar Profile										
Year	Seed1	Seed2	Seed3	Seed4	Seed5	Seed6	Seed7	Seed8	Seed9	Seed10
2018	32.38	30.98	27.44	33.31	32.65	27.87	29.06	31.15	27.84	34.30
2019	34.11	32.26	25.56	32.87	26.74	34.48	27.63	30.69	27.70	23.78
2020	23.17	25.69	23.67	25.94	23.33	26.26	20.20	30.13	24.08	30.92
2021	13.41	22.42	27.92	29.43	26.10	23.26	29.74	27.10	24.08	28.49
2022	24.23	29.74	30.52	23.62	33.56	29.40	16.52	24.76	27.17	26.06
2023	25.91	23.07	29.34	31.28	30.60	31.17	30.05	27.91	27.23	28.05
2024	30.09	28.86	24.60	28.90	34.35	26.00	32.95	30.41	29.70	25.59
2025	29.99	25.56	30.66	27.76	22.65	19.56	31.67	29.39	33.72	30.17
2026	30.25	25.42	28.51	30.72	26.38	31.40	36.68	37.17	28.65	32.22

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2027	32.39	24.67	32.03	39.00	29.27	31.93	32.56	32.23	31.58	32.94
2028	38.05	29.46	29.67	32.51	34.14	30.78	33.41	34.31	32.82	29.06
2029	33.42	33.32	36.38	34.25	33.41	30.10	34.04	33.48	35.59	30.53
2030	39.32	34.44	37.39	33.33	37.22	35.20	35.54	33.66	37.44	37.85
2031	34.97	31.86	36.85	33.45	36.95	34.28	34.05	31.29	35.13	38.94
2032	35.82	35.53	34.05	36.20	36.79	39.75	35.54	42.01	33.89	35.11
Levelized	30.48	29.53	30.32	32.10	31.24	30.49	30.56	32.08	30.44	31.33
			Average Levelized Avoided Cost Solar				**30.86**			

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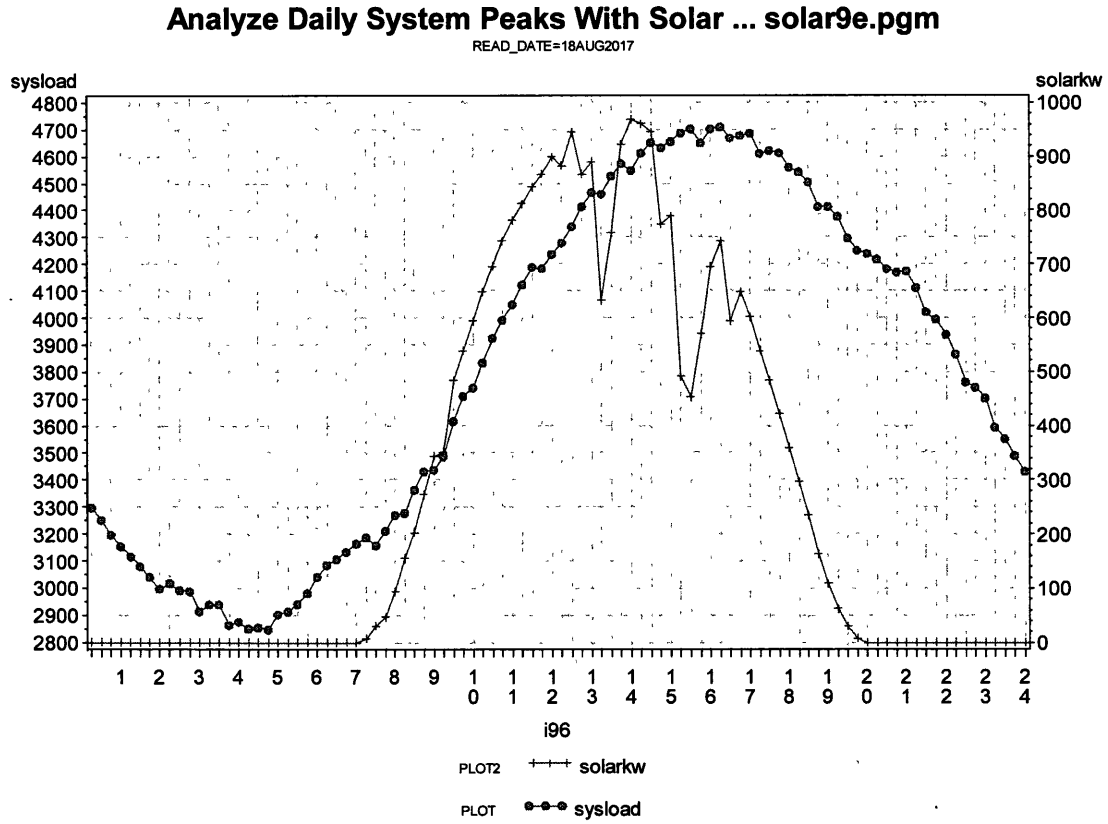
On Calculating the Capacity Benefit of Solar QFs

Introduction: Before reporting detailed calculations, it is instructive to compare the daily profile of the system with a solar profile. The following chart compares the system and solar profiles on August 18th, the summer peak day of 2017. The system load is measured on the left vertical axis and the solar on the right. The solar profile comes from an actual solar farm on the SCE&G system but is scaled to a maximum capacity of 1,000 kW for illustration. One of the first points to notice is that, during this summer day, the solar profile is positive for about 13 hours, from 7:15 am (0715 hours) until about 8:00 pm (2000 hours). The system peak is about 4,700 MWs and by 8:00 pm (2000 hours) it decreases to about 4,300 when solar stops producing power. This means that no matter how much solar capacity is added to the system on this day the maximum effect will be to reduce the peak by 400 MWs. This is because the solar output will be zero at 8:00 pm (2000 hours) and therefore could not reduce the load below 4,300 MWs.



The following chart compares the system load without the addition of solar with the system load that results when 200, 500, 800 and 1000 MWs of solar capacity are subtracted from the original system load. Referring to the chart, the system load can be seen to be about 4700 MWs occurring about 3:30

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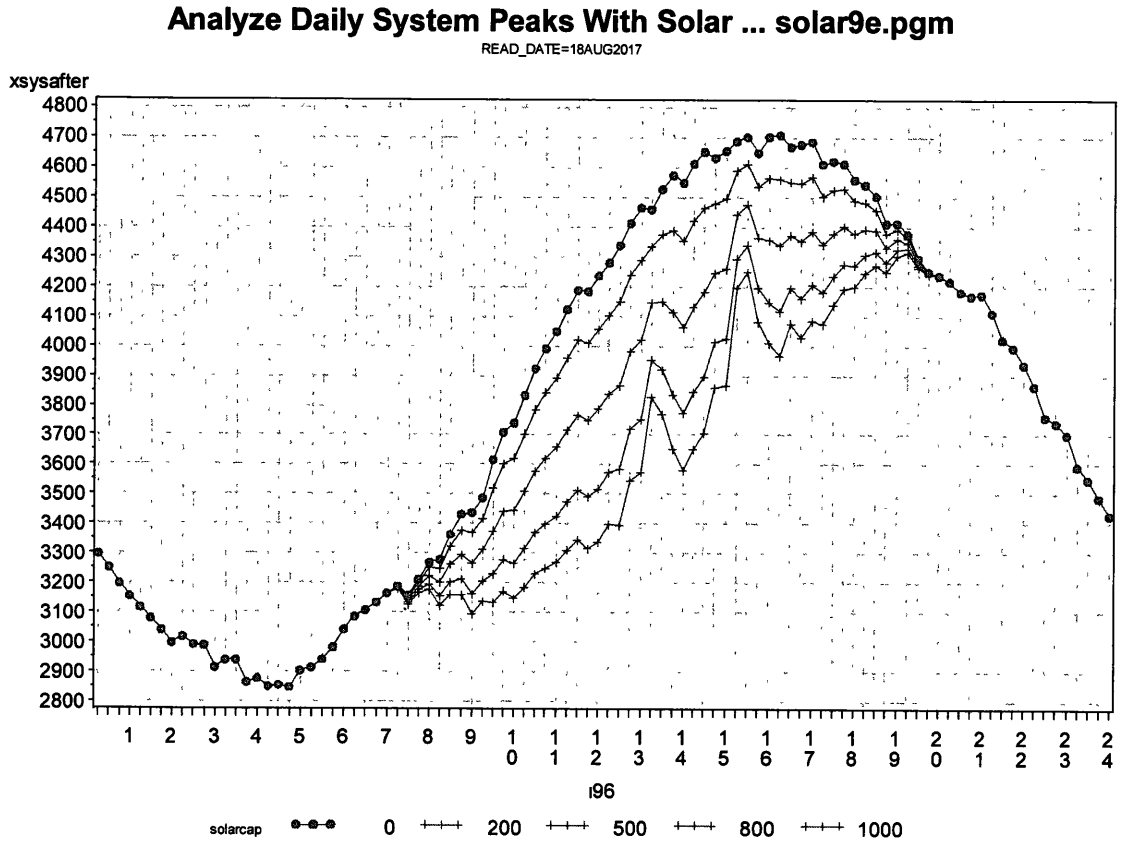
pm (1530 hours). When the effect of 200 MWs of solar is factored in, the load drops to about 4600 MWs at that same hour. When another 300 MWs of solar is added, the load drops another 125 MWs about at the same hour. However, with the addition of another 300 MWs making the solar total 800 MWs, the peak drops to about 4300 but the hour of the peak shifts to about 8:00 pm (2000 hours). At this point additional solar capacity will not affect the peak as can be seen when 200 MWs more is added making the total 1,000 MWs of solar. The peak remains at 4300 MWs at 8:00 pm (2000 hours).



A similar discussion can be made for a winter day. The following chart shows the system and solar profile for January 9th, the winter peak day of 2017. It is instructive to note that the solar profile is positive for about 10 hours from about 7:30 am (0730 hours) until about 5:30 pm (1730 hours). Since the system peaked at 7:15 am (0715 hours) on this day before solar generates power, no matter how much solar capacity is added to the system the peak demand of about 4500 MWs will not change. On this day, solar has no capacity value.

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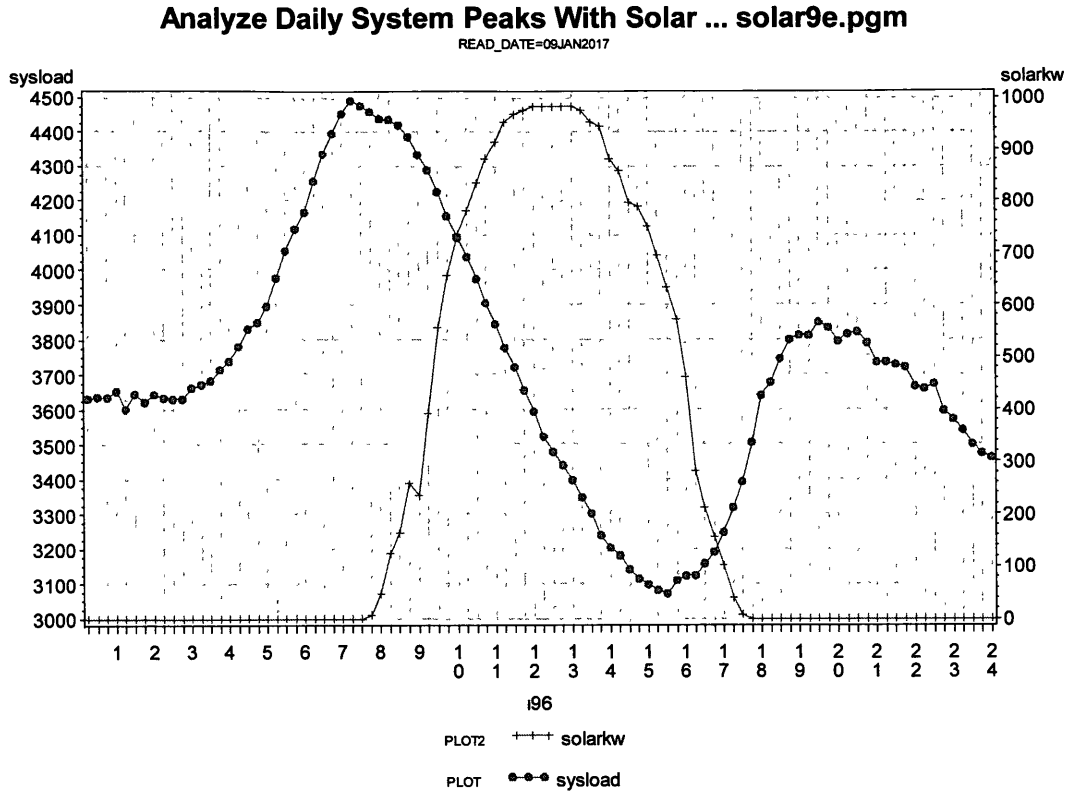
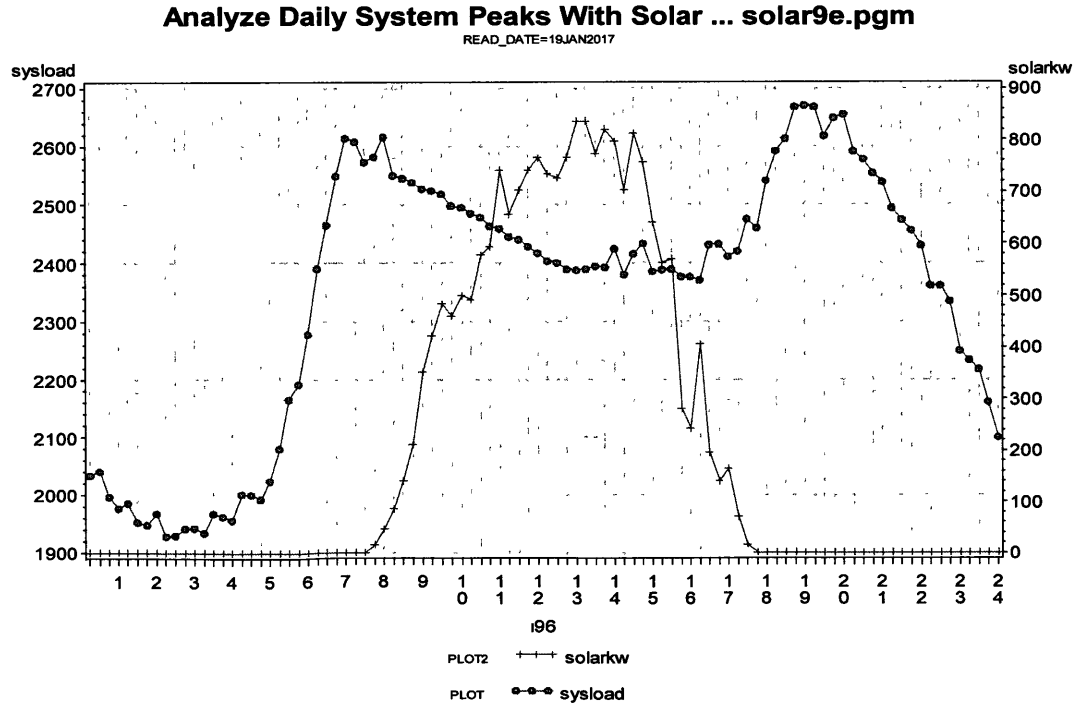


Many winter days are like this winter peak day in that the peak demand occurs either before or after the hours of solar output. The following chart contains similar information for January 19, 2017 when the system peaked just under 2700 MWs in the evening around 6:45 pm.



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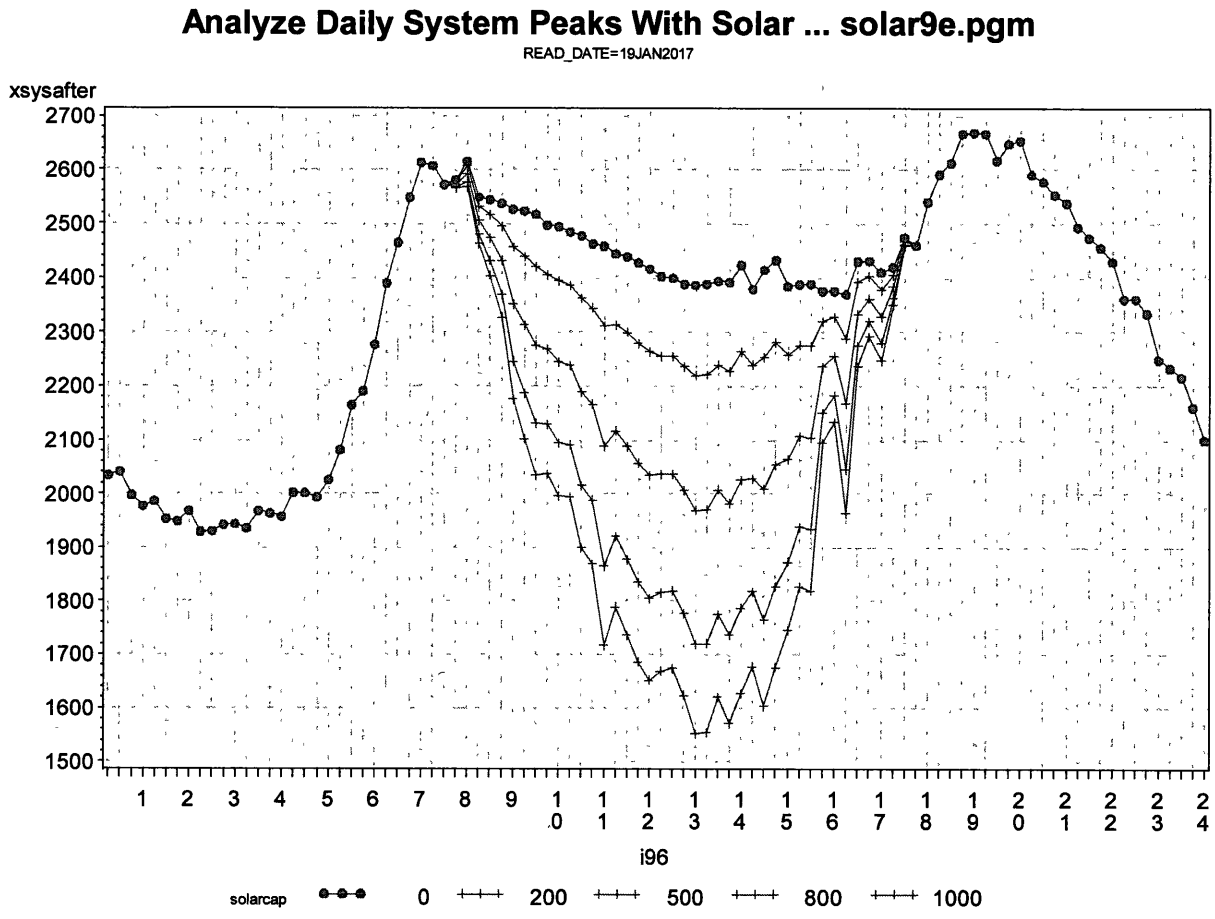
Below is the graph of the system load after adding 200, 500, 800 and then 1,000 MWs of solar capacity. The addition of solar certainly has a significant effect of the resulting load shape but notice that the peak demand is not affected.



Study Results: The previous charts and discussion are useful to understand what happens when solar capacity is added to the system but to have a complete picture it is necessary to look at all the days of the year. It has been shown that for at least two days the impact of solar on the need for capacity is zero. The following table shows the number of such days in the year by month for different levels of solar capacity. For example, if 800 MWs of solar are added to SCE&G's system in 2017, there would be 27 days in January on which the peak demand is not changed; 24 days in February, 27 in March, etc.

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Table 1

Number of Days By Month When Solar Has Zero Impact on the Peak Demand										
	Amount of Solar Capacity Added to the System									
Month	100	200	300	400	500	600	700	800	900	1000
1	27	27	27	27	27	27	27	27	28	28
2	18	19	20	22	23	23	24	24	24	25
3	22	23	26	26	26	26	27	27	29	29
4	6	8	9	10	13	17	18	20	21	22
5	3	3	3	4	6	6	7	7	7	7
6	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	1	1	2	2	3
9	1	2	2	2	2	2	3	5	5	6
10	14	15	16	16	20	22	25	25	26	26
11	18	21	21	22	22	22	23	23	24	24
12	21	21	22	22	23	23	23	23	23	24
Total	130	139	146	151	162	169	178	183	189	194

It appears that for 7 months of the year, 800 MWs of solar will have no effect of the daily peak demand on most of the days of the month. For 5 months, however, i.e. for May through September, 800 MWs of solar will impact the peak demand on most days of the month and on all of the days in June and July.

Solar Impact in Winter: Consideration of the winter months October through March supports the conclusion that solar has zero capacity value in winter. There are 182 days in these 6 months and on 149 of those days, 800 MWs of solar capacity has no impact on the system peak demand reflecting an 82% fail ratio. It is useful to note the time of the system peak demand in the last 4 winter seasons. The table below contains this information.

Table 2

Winter Peak Days on SCE&G's System		
Day of Peak	Peak MWs	Time of Occurrence
January 07, 2014	4,717	7:30 am
February 20, 2015	5,035	7:00 am
January 19, 2016	4,451	7:00 am
January 09, 2017	4,493	7:15 am

Since all four peak demands occurred before 7:30 am, the presence of solar capacity would not have helped serve the peak load.

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Solar Impact in Summer: The following tables show the results of the summer analysis. The first table shows the solar impact on the five highest peak days of the 2017 summer. For 800 MWs of solar added to the system, the average daily peak demand is reduced approximately 34.4% or about 275 MWs. The last 100 MWs of solar capacity, that is, the impact when solar capacity is increased from 700 MWs to 800 MWs, reduces the peak demand by 19.5 MWs on average which can also be expressed as 19.5%.

Table 3

5 Highest Summer Peak Days With 800 MWs of Solar				
Solar Farm	Nbr Days	Peak Reduction MWs	% Reduction	Last 100 MWs
Farm 1	5	313.8	39.2	24.5
Farm 2	5	273.8	34.2	24.7
Farm 3	5	223.4	27.9	15.6
Farm 4	5	340.0	42.5	21.4
Farm 5	5	262.5	32.8	11.0
Farm 6	5	204.1	25.5	17.7
Farm 7	5	310.2	38.8	21.9
Average			34.4	19.5

Analyzing the solar impact over the remaining days available in the summer season yields an average reduction in peak demand of 21.0% or 168 MWs. On an incremental basis, the impact of the last 100 MWs of solar is 9.6 MWs on average. The conclusion is that the last 100 MWs of capacity will provide about 9.6 MWs of system capacity relief for most of the summer season, i.e., during the months of May through October plus an additional 9.9 MWs on the summer peak day.

Table 4

Remaining Days of the Summer Season With 800 MWs of Solar				
Solar Farm	Nbr Days	Peak Reduction MWs	% Reduction	Last 100 MWs
Farm 1	148	153.6	19.2	8.7
Farm 2	179	152.1	19	10.4
Farm 3	122	167.7	21	8.2
Farm 4	163	176.5	22.1	10.4
Farm 5	163	188.5	23.6	9.7
Farm 6	179	174.5	21.8	9.9
Farm 7	179	162.1	20.3	10.1
Average			21.0	9.6

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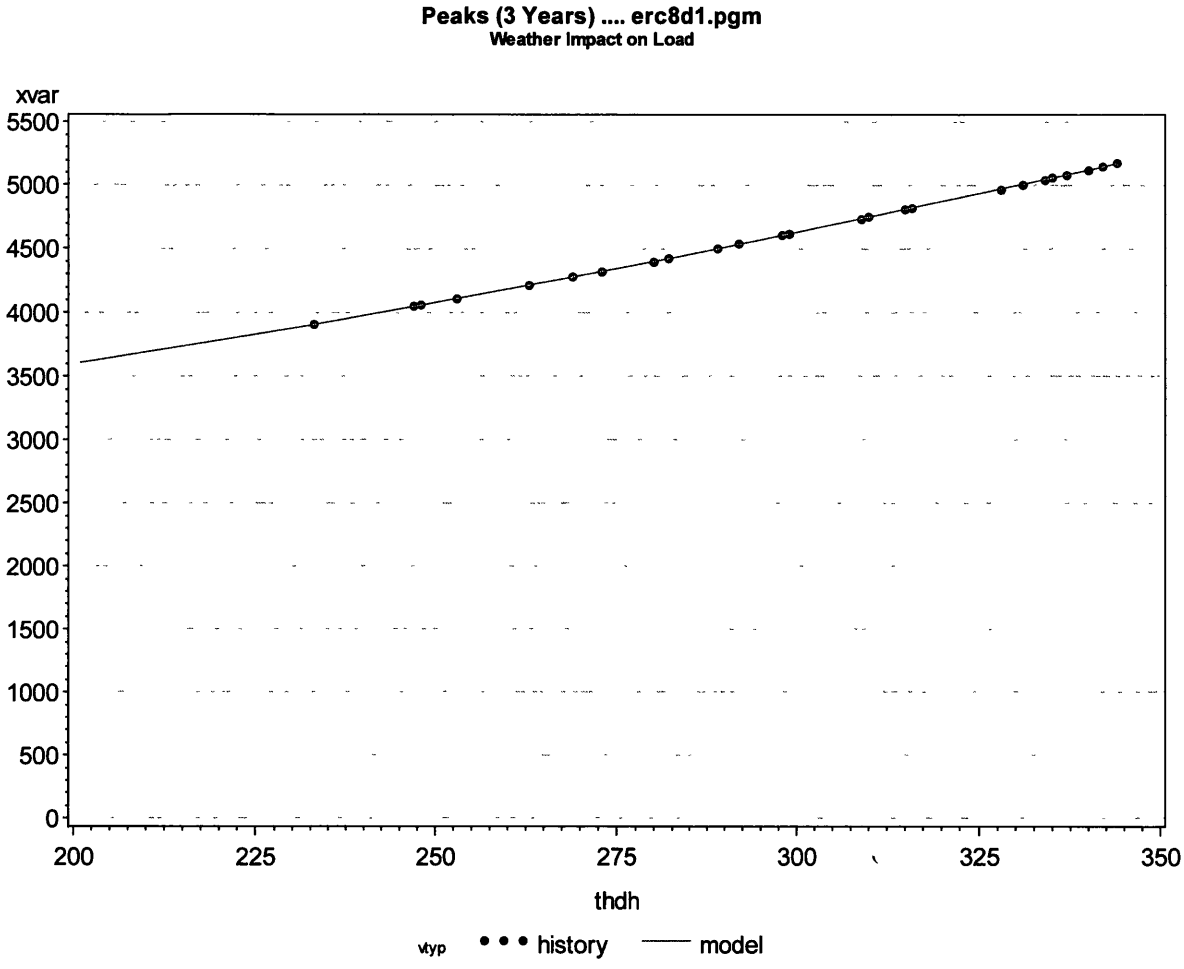
Exhibit No. ___ (JML-5)



PENGAD 800-631-6989
EXHIBIT
4/10/18
6
2018-2-E

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

Number of Observations Read	83
Number of Observations Used	56
Number of Observations with Missing Values	27

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	8180115	1363353	96.43	<.0001
Error	49	692805	14139		
Corrected Total	55	8872920			

Root MSE	118.90698	R-Square	0.9219
Dependent Mean	3833.51786	Adj R-Sq	0.9124
Coeff Var	3.10177		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	1	1747.32576	153.99535	11.35	<.0001	0
ihol	1	-647.15132	123.05644	-5.26	<.0001	1.05189
wkend	1	-436.10939	35.39243	-12.32	<.0001	1.16280
thdh	1	9.39066	0.64099	14.65	<.0001	1.09533
jan	1	109.05308	47.81469	2.28	0.0269	2.19160
feb	1	154.37914	49.20293	3.14	0.0029	2.02718
nov	1	-141.88750	64.24746	-2.21	0.0319	1.56398

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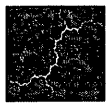
	Historical Date	Historical HDH	Estimated Peak
1	23-Jan-91	280	4486
2	20-Dec-91	282	4395
3	15-Mar-93	292	4489
4	19-Jan-94	340	5049
5	9-Feb-95	335	5048
6	5-Feb-96	344	5132
7	20-Dec-96	310	4658
8	13-Mar-98	289	4461
9	6-Jan-99	337	5021
10	27-Jan-00	299	4664
11	3-Jan-01	328	4937
12	8-Jan-02	247	4176
13	24-Jan-03	342	5068
14	29-Jan-04	263	4326
15	24-Jan-05	315	4814
16	10-Feb-06	253	4278
17	6-Feb-07	233	4090
18	4-Jan-08	316	4824
19	21-Jan-09	289	4570
20	11-Jan-10	309	4758
21	14-Jan-11	310	4767
22	4-Jan-12	298	4655
23	18-Feb-13	248	4231
24	7-Jan-14	334	4993
25	20-Feb-15	331	5010
26	19-Jan-16	273	4420
27	9-Jan-17	269	4382



Synapse
Energy Economics, Inc.

Devi Glick, Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Associate*, January 2018 – Present

Conducts research and provides consulting on energy sector issues.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017

Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy and identified over a billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO_2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement, and was submitted as an official federal comment, and led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales, and helped them identify alternative business models that would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

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The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

Prepared lesson plans, taught classes, graded papers and other coursework, met regularly with students.

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EPA*. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D.Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

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Avoided Cost of Transmission and Distribution Detail (nominal $)

Utility or jurisdiction	Source	Avoided T&D ($/kW-year)
Idaho Power	Idaho Power 2013	$0.00
Arizona Public Service	Mendota 2014	$0.00
Wisconsin	Cadmus 2013	$0.00
Indiana Michigan Power	I&M 2013	$0.00
State of Texas	Texas 2015	$0.00
Consumers Energy	Mendota 2014	$0.00
Vectren	Vectren 2014	$12.14
Nevada Power	NVE 2012	$12.23
Public Service Oklahoma	PSO 2014	$19.17
Ameren Missouri	Ameren 2014	$27.68
Xcel Energy Colorado	Xcel CO 2013	$28.40
Southwest Public Service	SPS 2013	$28.87
Potomac Edison	Exeter 2014	$30.69
Connecticut Light and Power	AESC 2013	$32.24
Baltimore Gas and Electric	Exeter 2014	$33.15
PGE Oregon	Mendota 2014	$33.20
National Grid Rhode Island	AESC 2013	$41.24
ComEd Illinois	Mendota 2014	$42.00
Consolidated Edison Non Network	Mendota 2014	$42.63
United Illuminating	AESC 2013	$47.82
MidAmerican South Dakota	Mendota 2014	$48.16
MidAmerican	Mendota 2014	$51.86
Northern Indiana Public Service	NIPSCO 2014	$52.25
PacifiCorp Oregon	Mendota 2014	$52.64
PacifiCorp Utah	Mendota 2014	$52.64
PacifiCorp Washington	Mendota 2014	$52.64
Xcel Energy Minnesota	Xcel MN 2012	$53.17
Southern California Edison	Mendota 2014	$53.49
Delmarva Power and Light	Exeter 2014	$55.43
Northwest Utilities	Mendota 2014	$65.59
Public Service New Hampshire	AESC 2013	$70.05
San Diego Gas and Electric	Mendota 2014	$73.32
Pacific Gas and Electric	Mendota 2014	$75.57
PEPCO	Exeter 2014	$79.12
Southern Maryland Electric Coop	Exeter 2014	$79.12
NSTAR	AESC 2013	$89.79
WMECO	AESC 2013	$98.35
Tucson Electric Power	Mendota 2014	$100.00
Unitil New Hampshire	AESC 2013	$102.29
Interstate Power and Light	Mendota 2014	$107.00
Consolidated Edison Network	Mendota 2014	$120.52
Vermont	AESC 2013	$158.15
Unitil Massachusetts	AESC 2013	$173.79
National Grid Massachusetts	AESC 2013	$200.01

Source: Baatz, Brendon. Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency. ACEEE: June 2015.

ACCEPTED FOR PROCESSING - 2018 April 5 7:32 AM - SCPSC - 2018-2-E - Page 17 of 19

EXHIBITS DCG 3 AND DCG 4 TO SURREBUTTAL TESTIMONY OF DEVI GLICK

ON BEHALF OF
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

On the Topics of
Avoided Cost Calculations and the Costs and Benefits of Solar Net Energy Metering

DOCKET NO. 2018-2-E

Synapse calculation of SCE&G's capacity needs with an adjustable reserve margin

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

(MW)

	YEAR	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
2	EE/Renewables Impact	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
3	Gross Territorial Peak	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5636	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																															
4	Existing	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	5672	5858	5672	5951	5765	6044	5858	6044	5858	6230	6044	6230	6044	6230	6044	6323	6230	6416
5	Existing Solar	58.73	0	96.36	0	161.6	0	302.79	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0
6	Demand Response	274	222	275	223	276	224	277	225	278	226	280	227	281	228	282	229	283	230	285	231	286	232	287	233	288	233	290	234	291	235
Additions:																															
7	Solar Plant	37.63	0	65.21	0	141.2	0																								
8	Peaking/Intermediate																												93		
9	Baseload		504										0	0																	
10	Retirements			85		-25																									
11	Total System Capacity	5648.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6255.8	6186	6256.8	6280	6350.8	6374	6445.8	6375	6446.8	6562	6633.8	6563	6634.8	6563	6636.8	6750	6823.8	6751
12	Firm Annual Purchase	300	0	0	0	0	0	0	0	0	0	0	0	25	25	0	0	0	0	50	0	0	0	0	0	50	0	0	0	0	0
13	Total Production Capability	5948.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6280.8	6211	6349.8	6280	6443.8	6374	6495.8	6375	6632.8	6562	6633.8	6563	6684.8	6563	6729.8	6750	6823.8	6751
Reserves																															
14	Margin (L13-L3)	871	1166	1023	1035	1071	1065	999	997	894	956	815	928	780	912	781	933	808	983	801	943	883	1089	833	1053	838	1011	831	1156	876	1114
15	% Reserve Margin (L14/L3)	17.2%	23.2%	20.0%	20.4%	20.7%	20.8%	19.0%	19.2%	16.7%	18.3%	15.0%	17.7%	14.2%	17.2%	14.0%	17.4%	14.3%	18.2%	14.1%	17.4%	15.4%	19.9%	14.4%	19.1%	14.3%	18.2%	14.1%	20.7%	14.7%	19.8%
	Min Reserve Margin	17%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%
	Capacity Gap	291.73	0	0	0	0	0	0	0	0	0	0	0	15.34	14	91.86	0	74.24	0	46.5	0	108.2	0	0	0	30.78	0	88.06	0	0	0
	Dynamic Peaking Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	93	0	93	0	0	0	186	0	0	0	0	0	93	0	0	0

Winter Reserve Margin	17%
Summer Reserve Margin	14%

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Synopse calculation of SCE&G's capacity needs with an adjustable reserve margin

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

(MW)

		YEAR	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
			S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																																
	1	Baseline Trend	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
	2	EE/Renewables Impact	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
	3	Gross Territorial Peak	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5638	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																																
	4	Existing	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	5672	5858	5672	5951	5765	6044	5858	6044	5858	6230	6044	6230	6044	6230	6044	6323	6230	6416
	5	Existing Solar	58.73	0	96.36	0	161.6	0	302.79	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0
	6	Demand Response	274	222	275	223	276	324	277	325	278	326	280	327	281	328	282	329	283	330	285	331	286	332	287	333	288	333	290	334	291	335
Additions:																																
	7	Solar Plant	37.63	0	65.21	0	141.2	0																								
	8	Peaking/Intermediate																														
	9	Baseload		504										0	0															93		
	10	Retirements			-85		-25																									
	11	Total System Capacity	5648.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6255.8	6186	6256.8	6280	6350.8	6374	6445.8	6375	6446.8	6562	6633.8	6563	6634.8	6563	6636.8	6750	6823.8	6751
	12	Firm Annual Purchase	300	0	0	0	0	0	0	0	0	0	0	0	25	0	0	0	0	0	50	0	0	0	0	0	50	0	0	0	0	0
	13	Total Production Capability	5948.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6280.8	6186	6349.8	6280	6443.8	6374	6495.8	6375	6632.8	6562	6633.8	6563	6684.8	6563	6729.8	6750	6823.8	6751
Reserves																																
	14	Margin (L13-L3)	871	1166	1023	1035	1071	1065	999	997	894	956	815	928	780	887	781	933	808	983	801	943	883	1089	833	1053	838	1011	831	1156	876	1114
	15	% Reserve Margin (L14/L3)	17.2%	23.2%	20.0%	20.4%	20.7%	20.8%	19.0%	19.2%	16.7%	18.3%	15.0%	17.7%	14.2%	16.7%	14.0%	17.4%	14.3%	18.2%	14.1%	17.4%	15.4%	19.9%	14.4%	19.1%	14.3%	18.2%	14.1%	20.7%	14.7%	19.8%
		Min Reserve Margin	17%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
		Capacity Gap	291.73	0	0	0	0	0	0	0	0	0	0	0	15.34	0	91.86	0	74.24	0	46.5	0	108.2	0	0	0	30.78	0	88.06	0	0	0
		Dynamic Peaking Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	93	0	93	0	0	0	186	0	0	0	0	0	93	0	0	0

Winter Reserve Margin	14%
Summer Reserve Margin	14%

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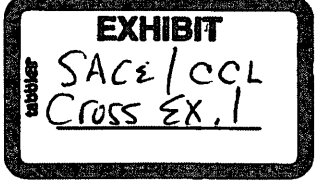
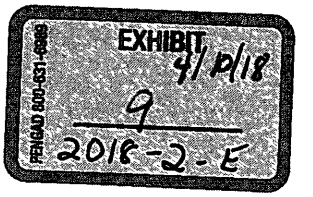


Matthew W. Gissendanner
Assistant General Counsel

matthew.gissendanner@scana.com

February 28, 2018



VIA ELECTRONIC FILING

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

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

Dear Ms. Boyd:

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

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

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

Very truly yours,

Matthew W. Gissendanner

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

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BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2018-___-E

IN RE:

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

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

Jeffrey Nelson, Esquire
Office of Regulatory Staff
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Karen M. Scruggs

Cayce, South Carolina

This 28th day of February 2018

2018

Integrated

Resource

Plan

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Introduction

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

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

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

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

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

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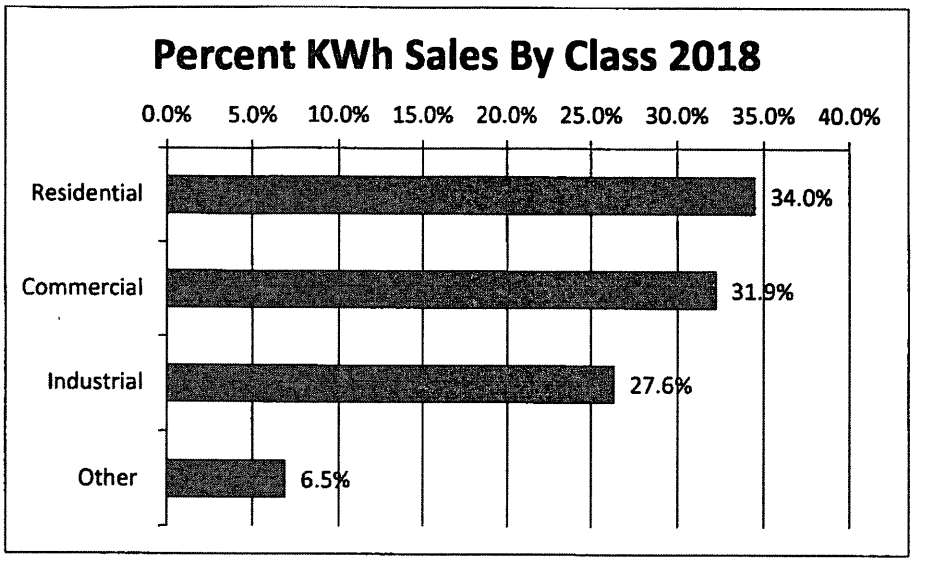

SCE&G's forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for large customer expansions, new large customers and energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained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

A. System Peak Demand: Summer vs. Winter

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

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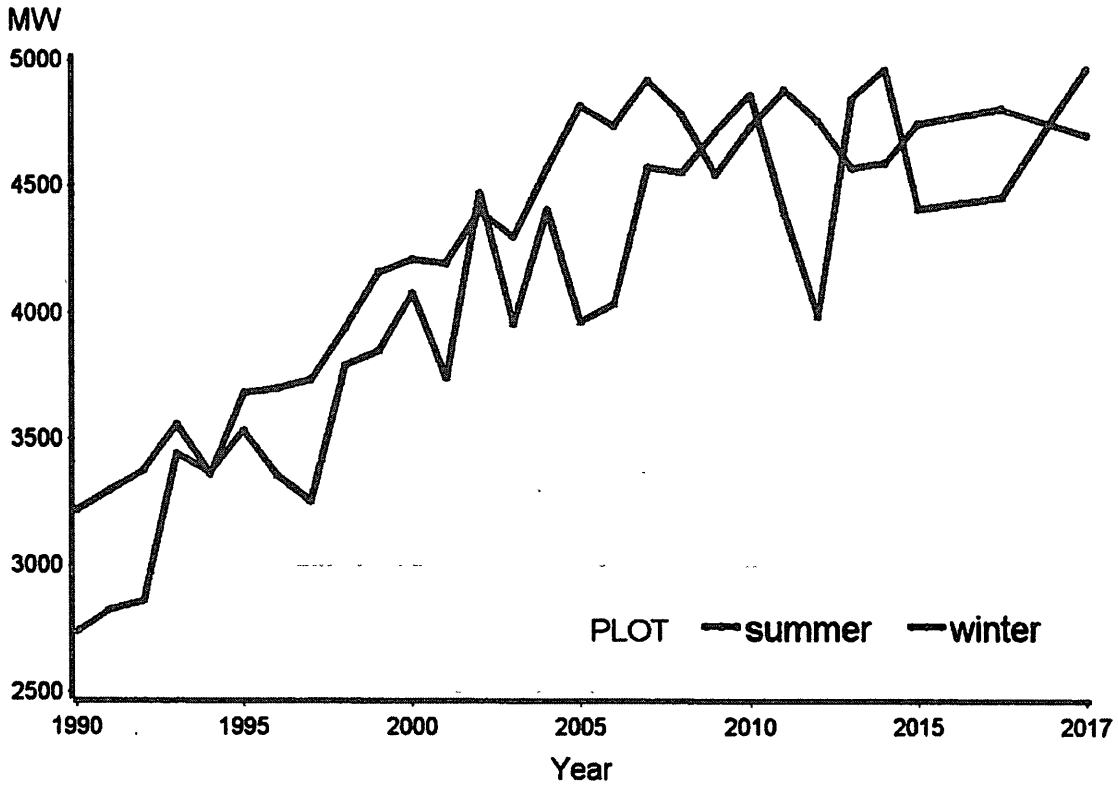
Comparison of SCE&G Annual Summer and Winter Peak History
1990-2017



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

B. Demand Side Management (DSM) Impact on Forecast

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

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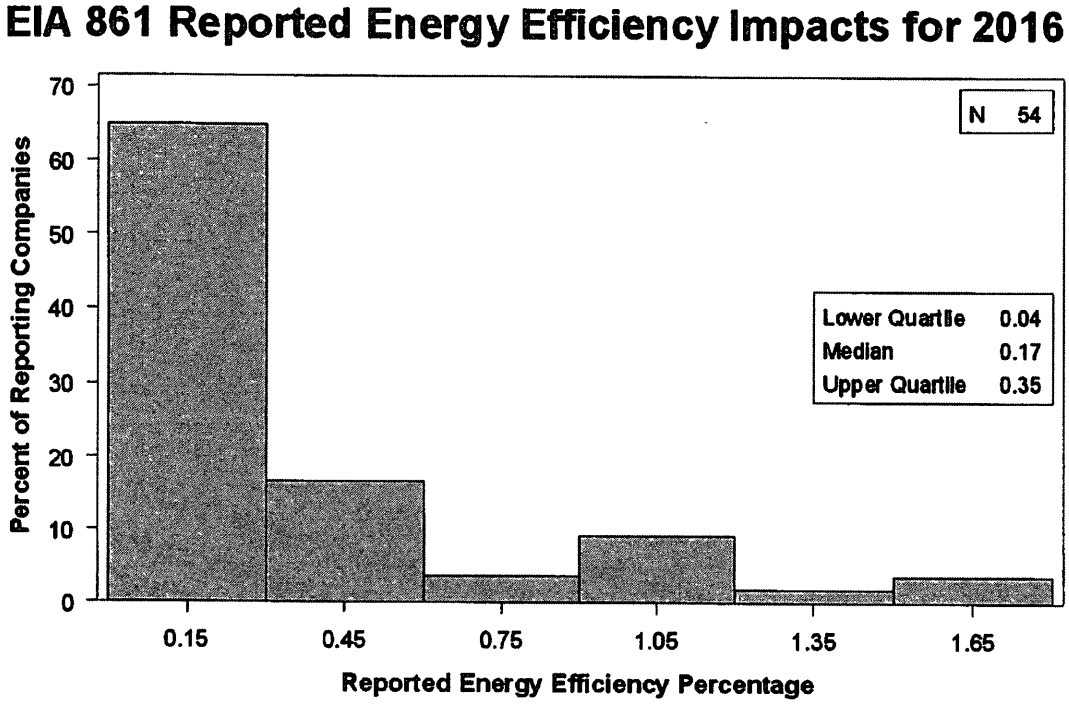
below shows graphically the distribution of reported results. The median EE impact was 0.17%. Thus, half the companies reported results higher and half lower than this median value. SCE&G's expectation for 2019 places it in the top half of the distribution. Clearly, SCE&G's EE programs compare favorably with other companies in the Southeast.



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

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

C. Energy Efficiency Adjustments

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

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

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

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

The first adjustment relates to federal mandates for air-conditioning units and heat pumps. In 2015 the minimum Seasonal Energy Efficiency Ratio ("SEER") increased from 13 to 14 for South Carolina and other regions of the United States. This was the first change in SEER ratings since 2006, when the minimum SEER for newly manufactured appliances was raised from 10 to 13. The cooling load for a house that replaced a 10 SEER unit with a 13 SEER unit

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

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

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

The final adjustment to the baseline forecast was to account for SCE&G's set of energy efficiency and new solar programs. These energy efficiency programs along with the others in SCE&G's existing DSM portfolio are discussed later in the IRP. In developing the forecast it

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was assumed that the impacts of these programs were captured in the baseline forecast for the next two years but thereafter had to be reflected in the forecast on an incremental basis.

D. Load Impact of Energy Efficiency and Demand Response Programs

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

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

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

A. Demand Side Management

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

1. Energy Efficiency

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

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

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

   ii. **Media/Channel Placement:** SCE&G is committed to customer education on available programs and services designed to help them be more energy efficient. To reach as many customers as possible, a diverse mix of channels is used, including both paid and earned media. Direct mail, bill inserts, internet radio, online strategies and

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community events continue to prove successful in reaching and engaging most customers. Extensive outreach via social media continues to optimize coverage and increase the opportunity to inform customers. Year-round news coverage is equally important and is consistently integrated into the media mix, particularly during peak winter and summer months when usage is high.

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

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

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

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

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

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

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

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

v. **Neighborhood Energy Efficiency Program** provides income-qualified customers with energy efficiency education and direct installation of multiple low-cost energy conservation measures as part of a neighborhood door-to-door sweep approach to reach customers. In 2017, neighborhoods in Aiken County, Fairfax/Brunson, Edgefield and North Charleston participated in the program. Additionally, the Neighborhood Energy Efficiency Program continued offerings to

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mobile and manufactured homes to include additional measures specific to this housing stock and fully transitioned from providing CFLs to LEDs bulbs.

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

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

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

2. Load Management Programs

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

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

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

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

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

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

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

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B. Supply Side Management

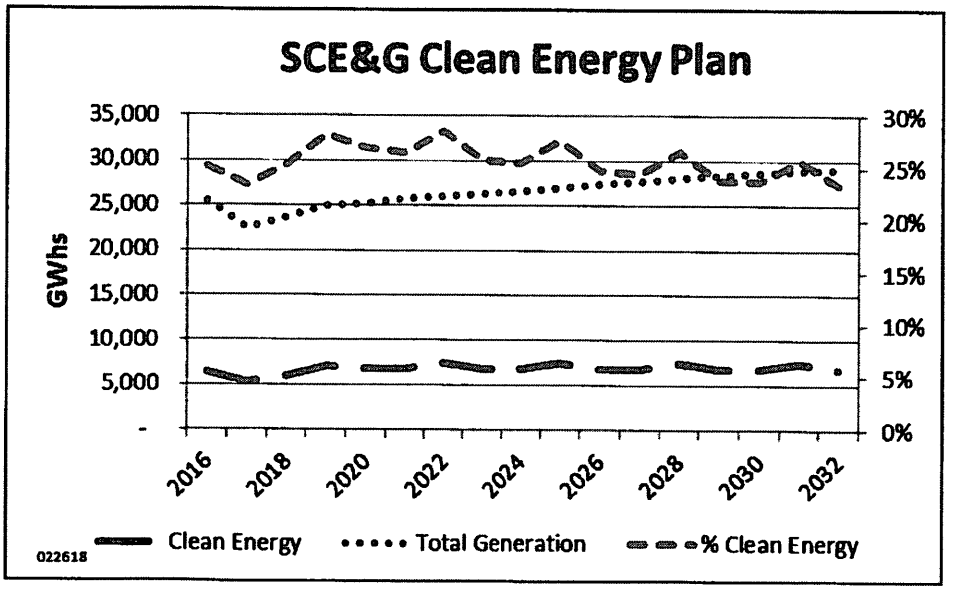
Clean Energy at SCE&G

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

1. Existing Sources of Clean Energy

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

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



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

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

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

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

c. **Distributed Energy Resource ("DER") Program:** SCE&G continues to manage the DER Customer Scale programs to include the approval and interconnection of systems under the NEM 2.0 rate. SCE&G also is processing the final 12.5 MW of Commercial

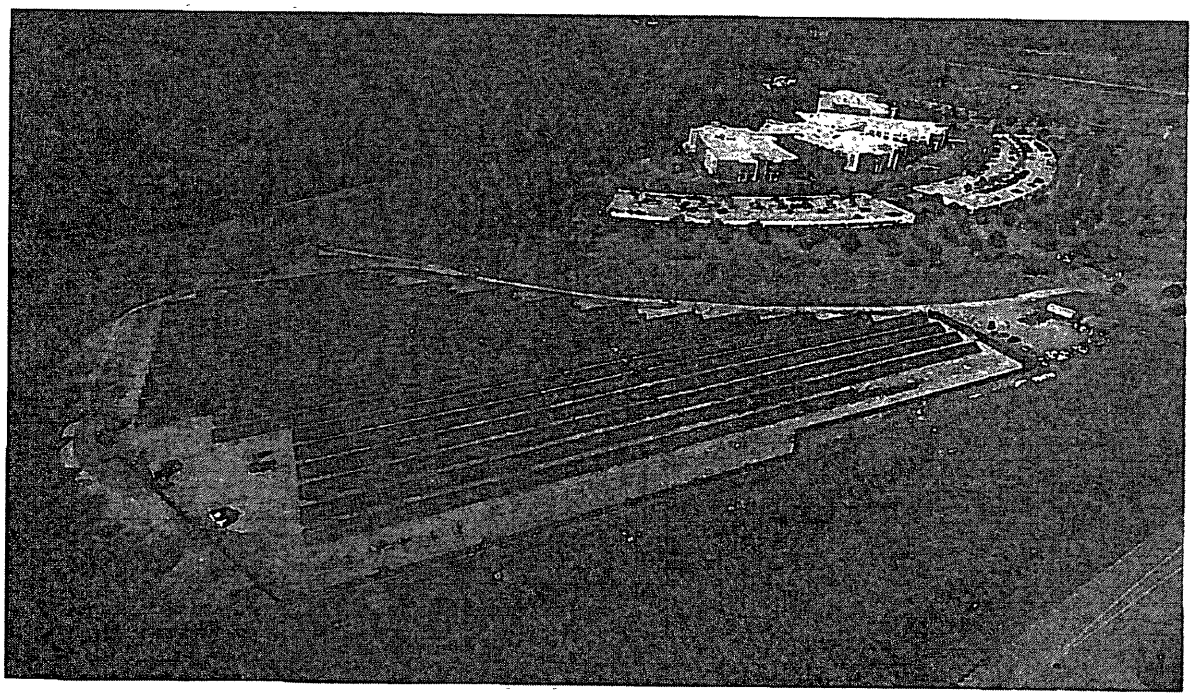
and Industrial Bill Credit Agreement interconnections with an April 27, 2018, deadline. Finally, SCE&G anticipates that 14 MW of Community Solar farms will become interconnected in the first half of 2018, with another 2 MW AC in the first quarter of 2019.

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

Otarre Solar Park facts:

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

Otarre Solar Farm, Cayce, SC



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Jerry Zucker Solar Park facts:

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

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

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

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

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

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

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

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

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2. Future Clean Energy

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

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

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

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

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

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

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

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

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

c. Smart Grid Activities:

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

Distribution Automation: SCE&G is continuing to expand the penetration of automated Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the system. SCE&G has approximately 1,060 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing outage times to affected customers. Some of these isolating switches can communicate with each

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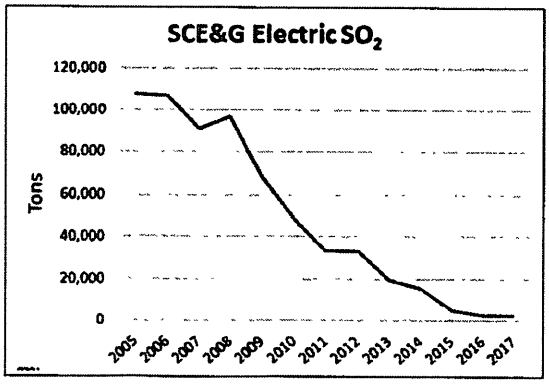
other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. SCE&G continues to evaluate systems that will further enable these automated devices to communicate with each other and safely reconfigure the system in a fully automated fashion, let operators know exactly where the faulted section of a line is, and monitor the status of the system as it is affected by outages, switching, and customer generation (solar).

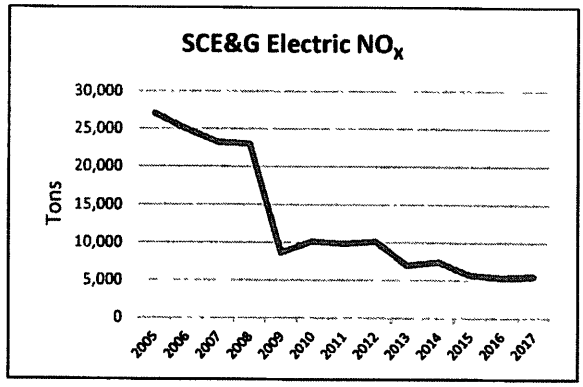
d. Environmental Mitigation Activities: The Cross State Air Pollution Rule (CSAPR), sets emission limits for annual and seasonal NO_X and for annual SO_2. The Acid Rain Program (ARP) also limits annual SO_2 emissions.

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

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

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





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

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regulations for mercury, the company has also installed carbon injection systems at Williams, Wateree and Cope. This will allow for additional control of mercury emissions if needed to comply with MATS requirements.

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

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

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

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

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

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

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

3. Summary of Proposed and Recently Finalized Environmental Regulations

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

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

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

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

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

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

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

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

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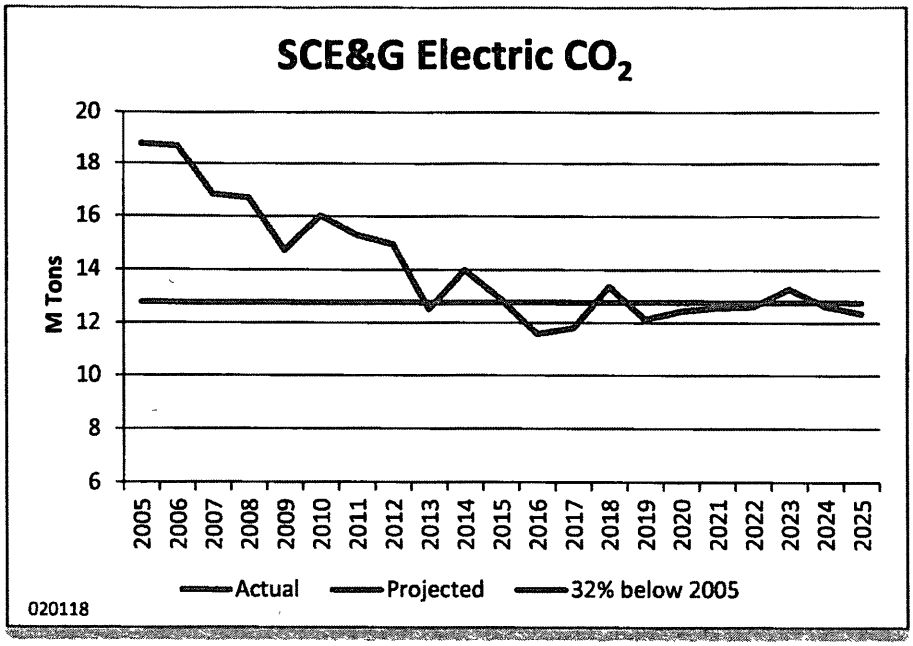

However, on February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. As a result of an Executive Order on March 28, 2017, the EPA placed the rule under review and the Court of Appeals agreed to hold the case in abeyance. On October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

d. Cooling Water Intake Structures: The Clean Water Act Section 316(b) Existing Facilities Rule became effective on October 14, 2014. This rule is intended to reduce impacts to fish and shellfish due to impingement, when organisms are trapped against inlet screens, and entrainment, when small organisms are drawn through the screens into the facility's cooling water system. Facilities capable of withdrawing at least 2 million gallons per day are generally subject to the rule. Facilities that are subject to the rule

must, at a minimum, submit a series of reports which describe the design and operation of the cooling water intake, as well as physical and biological characteristics of the cooling water source waterbody. For some facilities, operational or design changes will be necessary to meet the requirements of the rule. Potential design changes range from enhanced screening and reconfiguration of water intake systems to installation of closed-cycle cooling towers to reduce flow rates. Of the SCE&G generating facilities potentially subject to the rule, two stations, Wateree and Cope Stations, currently meet Best Technology Available (BTA) requirements for impingement mortality and entrainment. Two other stations, McMeekin and Jasper Stations, have been determined to be not-in-scope of the rule. SCE&G has conducted entrainment studies that demonstrate that Summer Station's existing intake structure fully complies with the rule. A biological study plan, which would evaluate current impacts to fish and shellfish, is being developed for Urquhart Station. Finally, Williams Station was issued a permit in December 2016 that requires biologic and intake study plans be conducted over the five year permit life. Modifications to the Williams Station intake structure, if any, may be delayed due to interferences of this intake with the Charleston Water Service intake for drinking water supplied to the Charleston Metro area.

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

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

CCR landfills at Cope, Wateree, and Williams Station are subject to the rule. Ponds at Wateree and Williams station are also covered by the rule. Notwithstanding this new CCR rule, SCE&G has already closed its ash storage ponds or has begun the process

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of ash pond closure at all of its operating facilities. Those ash storage ponds that are still open are subjected to a rigorous inspection and maintenance program to ensure the safe management of those units. SCE&G will continue to operate ponds for flue-gas desulfurization (FGD) solids for the foreseeable future, and will continue to operate CCR landfills.

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

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

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

Under the Clean Water Act, compliance with applicable limitations is achieved under State-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every 5 years) any new effluent limitations are incorporated. State environmental regulators will modify each renewed NPDES permit to match more restrictive standards, thus requiring utilities to retrofit affected facilities

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with new wastewater treatment technologies. Compliance dates will vary by type of wastewater and some will be based on a plant's 5-year permit renewal cycle and thus may range from 2020 to 2023. Based on the proposed rule, SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree at a minimum.

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

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

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

4. Supply Side Resources at SCE&G

a. **Existing Supply Resources:** SCE&G owns and operates three (3) coal-fired fossil fuel plants, two (2) gas-fired steam plants, two (2) combined cycle gas turbine/steam generator plants (gas/oil fired), seven (7) peaking turbine plants, four (4) hydroelectric generating plants, and one Pumped Storage Facility. In addition, SCE&G receives the output of 85 MWs from a cogeneration facility. The total fossil-hydro generating capability rating of these facilities is 4,586 MWs in summer and 4,758 MWs

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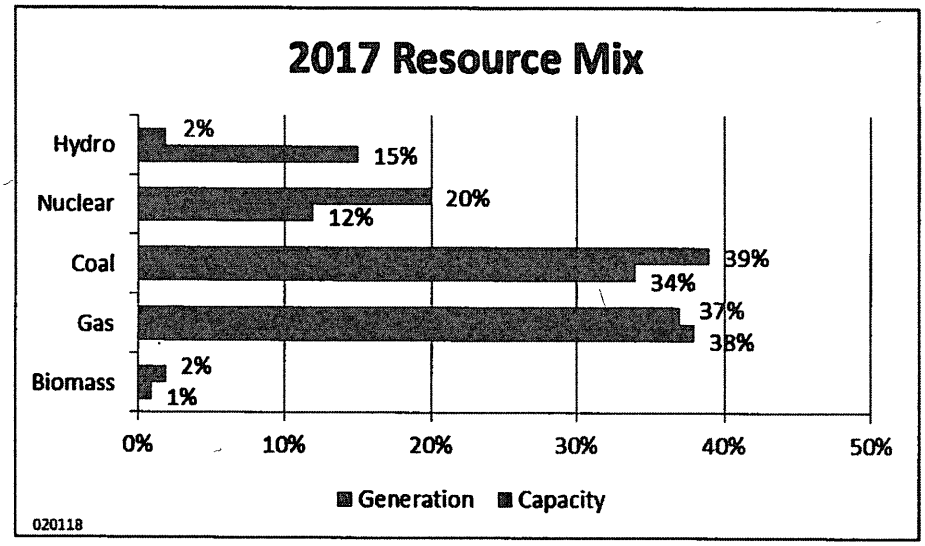
in winter. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer and winter seasons. When SCE&G's nuclear capacity (647 MWs in summer and 661 MWs in winter), a long term capacity purchase (25 MWs), additional capacity (20 MWs) provided through a contract with the Southeastern Power Administration and 96MWs of summer only utility scale solar are added, SCE&G's total supply capacity is 5,374 MWs in summer and 5,464 MWs in winter. This is summarized in the table on the following page.

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



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Existing Long Term Supply Resources

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

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

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

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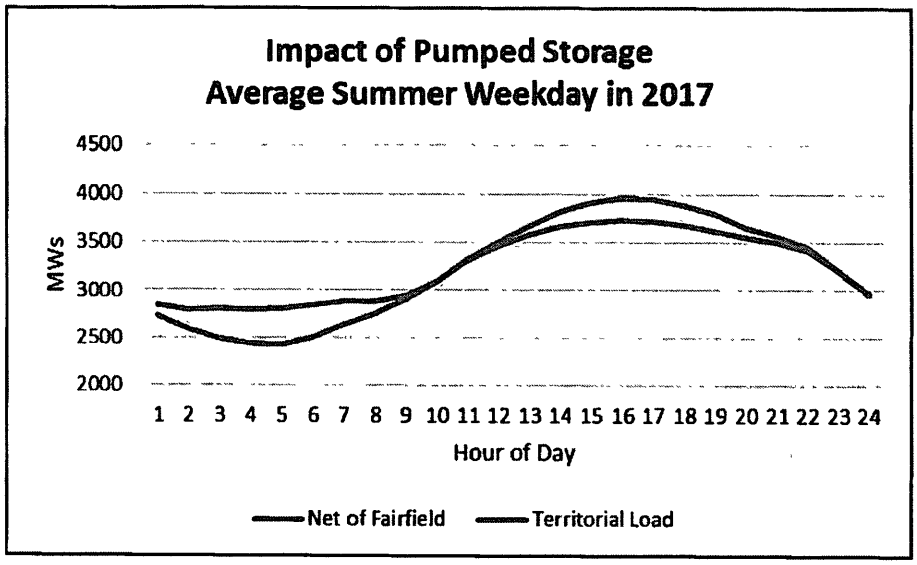
b. DSM from the Supply Side: SCE&G is able to achieve a DSM-like impact from the supply side using its Fairfield Pumped Storage Plant. The Company uses off-peak energy to pump water uphill into the Monticello Reservoir and then displaces on-peak generation by releasing the water and generating power.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



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

c. Planning Reserve Margin: Summer and Winter: All electric utilities require supply reserves to mitigate the risk of not being able to serve their load requirement because of demand-side related risk and supply-side related risk. Demand-side risk results from uncertainty in the level of demand which can increase because of abnormal weather or other unforeseen circumstances. Supply-side risk results from the possibility

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of supply resources either not being available at all or their capacity being reduced because of mechanical, fuel, weather or other circumstances. SCE&G is also required to carry operating reserves sufficient to meet its VACAR reserve sharing agreement. While SCE&G's share of the VACAR reserves can change each year, it is typically within a few megawatts of 200 MWs which is the amount SCE&G uses in its planning.

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

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

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

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

Background

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

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

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

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

On December 28, 2017 SCE&G filed a formal request with the Nuclear Regulatory Commission (NRC) to withdraw the combined operating licenses (COLs) for VC Summer Station Units 2 & 3. This action helps to ensure SCE&G captures approximately $2 billion in tax benefits for our customers to offset the costs of the new nuclear project. In its notification to the NRC, SCE&G states that it has irrevocably abandoned its interests in the VCS Units 2 and 3. All of its completion and preservation

activities have ceased. Current work is limited to only those actions required to place the site in a safe condition, terminate construction and close active permits concerns.

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

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

f. **Battery Storage on the Grid and in the Home:** Battery storage systems are likely to play a significant role in the future, both on the grid and in the home. The cost of battery storage has been decreasing consistently over the last several years and the technology continues to improve. Today battery storage can be cost effective in select grid integrations when supplying necessary stabilization services such as frequency

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response and voltage regulation. Batteries may also offer solutions to system integration challenges associated with intermittent renewable generation. Often these applications require specific, real-time analysis by the utility in examining the available battery storage solutions and the impact they have to the utility's transmission and distribution systems. This analysis is especially important in determining the potential for cost effectively storing and shifting large amounts of renewable energy. The dominant technologies currently are lithium-ion and a variety of flow batteries. Lithium-ion batteries have a high density storage coupled with a quick response time while flow batteries are better able to store energy for longer periods of time, hours to days. SCE&G will continue to monitor developments in battery storage technologies and their cost, and look for ways to improve the economics and reliability of service to our customers.

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

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

The capacity related to the two combined cycle plants projected is shown on line 9. The first combined cycle plant is the Columbia Energy Center plant that is expected to become part of SCE&G no later than January 1, 2019. By the winter of 2023 the system will be short of capacity by 200MWs and a second combined cycle is added. On line 10 the resource plan shows a decrease in capacity of 85 MWs in 2018 and another decrease of 25 MWs in 2020. The reduction of 85 MWs represents the loss of the Kapstone generator and the 25 MWs is the expiration of a power purchase contract with Santee Cooper. The need for firm capacity purchases is shown on line 12. The Company has

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secured the purchase of 300 MWs in 2018. Capacity is added to maintain the SCE&G's winter planning reserve margin above a minimum of 21%. The resource plan thus constructed represents one possible way to reliably meet the increasing demand of our customers.

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

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

	YEAR	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
2	EE/Renewables Impact	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
3	Gross Territorial Peak	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5636	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																															
4	Existing	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	6212	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6275	6491
5	Existing Solar	58 73	0	96.36	0	161.6	0	302.79	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302 8	0	302.8	0	302 8	0	302.8	0	302.8	0
6	Demand Response	274	222	275	223	276	324	277	325	278	326	280	327	281	328	282	329	283	330	285	331	286	332	287	333	288	333	290	334	291	335
	Additions:																														
7	Solar Plant	37.63	0	65.21	0	141.2	0																								
8	Peaking/Intermediate																												93		
9	Baseload		504										540	-30																	
10	Retirements			-85		-25																									
11	Total System Capacity	5648	6190	6134	6108	6251	6182	6251.8	6183	6253	6184	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6828
12	Firm Annual Purchase	300			50		25		100		150																				
13	Total Production Capability	5948	6190	6134	6156	6251	6207	6251.8	6283	6253	6334	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6826
Reserves																															
14	Margin (L13-L3)	871.4	1166	1023	1085	1071	1090	998.79	1097	893.8	1106	814.8	1468	1265	1427	1198	1380	1132	1337	1075	1297	1021	1257	970.8	1221	925.8	1179	875.8	1231	920.8	1189
15	% Reserve Margin (L14/L3)	17.2%	23.2%	20.0%	21.4%	20.7%	21.3%	19.0%	21.2%	16.7%	21 2%	15.0%	27.9%	23.0%	26.9%	21.5%	25.8%	20.1%	24.8%	18.9%	23.9%	17.8%	23.0%	16.7%	22.2%	15 8%	21.2%	14 8%	22.0%	15.5%	21.1%

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III. Transmission System Assessment and Planning

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

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

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

> *The requirements of the SCE&G "LONG RANGE PLANNING CRITERIA" will be satisfied if the system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.*

a. Loss of any bus and associated facilities operating at a voltage level of 115kV or above
b. Loss of any line operating at a voltage level of 115kV or above
c. Loss of entire generating capability in any one plant
d. Loss of all circuits on a common structure
e. Loss of any transmission transformer
f. Loss of any generating unit simultaneous with the loss of a single transmission line

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

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

the Federal Energy Regulatory Commission ("FERC").

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

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

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

The following is a list of joint studies with neighboring transmission planners completed over

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the past year:

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

The acronyms used above have the following reference:

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

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

Eastern Interconnection Planning Collaborative (EIPC)

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

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

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

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including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options.

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Appendix A

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Short Range Methodology

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

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

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

Regression Models

Regression analysis is a method of developing an equation which relates one variable, such as usage, to one or more other variables which help explain fluctuations and trends in the first. This method is mathematically constructed so that the resulting combination of explanatory variables produces the smallest squared error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the

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variable being explained. Several statistics which indicate the success of the regression analysis fit are shown for each model. Several of these indicators are R^2, Root Mean Squared Error, Durbin-Watson Statistic, F-Statistic, and the T-Statistics of the Coefficient. PROC REG of SAS was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

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

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

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

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

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ARIMA Models

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

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

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

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

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

$$Z_t = u + Y_1 (B) X_{i,t} + q(B)/ f(B) a_t$$

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

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

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

refinements in the tentative model. The iterative process is repeated until a satisfactory model is found.

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

Electric Sales Assumptions

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

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

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weighted by cycle billing. Adding Company Use and unaccounted energy to monthly territorial sales produces electric generation requirements.

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1. TABLE 1 Short-Term Forecasting Groups

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

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

TABLE 2

Summary of Methodologies Used To Produce
The Short Range Forecast

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

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Appendix B

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Long Range Sales Forecast

Electric Sales Forecast

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

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

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

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Forecast Methodology

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

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

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

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

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

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

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

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

Economic Assumptions

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

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

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

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contained in the short-term projections.

Peak Demand Forecast

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

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY'S FIRST DATA REQUEST
DOCKET NO. 2018-2-E

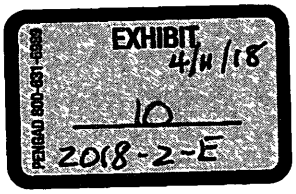
REQUEST 2:

Please provide an estimate of the four avoided energy costs for PR-2 under the methodology approved under Docket 2017-2-E calculated with May and October as part of the "peak season," for both solar and generic resources. This could be provided in a format similar to Table 2 of Joseph M. Lynch's testimony.

RESPONSE 2:

May and October were not included as part of the peak season in the methodology approved under Docket No. 2017-2-E. Below is an estimate of the four avoided energy costs for PR-2 under the methodology approved under Docket No. 2017-2-E.

$/MWH by Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018-2022	32.54	29.45	33.34	31.97
2023-2027	36.72	33.70	36.18	34.95
2028-2032	43.75	37.74	40.71	39.10



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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Resources and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, South Carolina Office of Regulatory Staff.

Resource Planning:

- Authored the Locational Net Benefits Analysis tool used by the California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas.
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island; demand response from large customers; and new clean power generation.
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments.
- Evaluated the sale value of hydroelectric assets in the Western United States.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts.
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Principal investigator for the CEC EPIC project on valuing distributed energy resources on a local area basis with an emphasis on solar plus storage.
- Author of the "E3 Calculator" tool used as the basis for all energy efficiency programs evaluations in California since 2006.
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities.
- Co-author of the NYSERDA Solar Value Stack Calculator to help contractors better estimate compensation for specific solar projects.

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- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions. Also, authored the model's sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs.
- Coauthor of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005.
- Principal consultant for the California Energy Commission's Title-24 building standards to reflect how the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage.
- Principal investigator for the 1992 EPRI report, Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects.
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation.

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities the United States, Canada, and the Middle East.
- Principal author of the Full Value Tariff and Retail Rate Choices report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding.
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings in 2008, 2010, and ongoing.
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions.
- Consulted to the New York State Public Service Commission on the appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and the appropriate cost tests.
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997). Principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix).
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs.
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs.
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work in the area includes marginal cost-based revenue allocation and rate design, estimation of area and time specific marginal costs; incorporation of customer outage costs into planning criteria designing a comprehensive billing and information management system for a major ESP operating in California.

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in the California central valley.
- Developed the quantitative modeling of the net benefits to the California grid of SDG&E's Sunrise Powerlink project. The work was performed in support of the CAISO's testimonies in that proceeding.

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- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO.
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation.
- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades.
- Developed the cost basis for BC Hydro's wholesale transmission tariffs.
- Provided support to for utility regulatory filings, including testimony writing and other litigation services.

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluation of electricity sector greenhouse gas emissions and tradeoffs.
- Primary architect of long term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept. The projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models.
- Served as PG&E's expert witness on revenue allocation and rate design in testimonies before the California Public Utilities Commission (CPUC). Was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC. and extending their application to cost effectiveness analyses of DSM programs. Additional analytical work included creating interactive negotiation analysis programs, and forecasting electric rates trends for short-term planning.

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped developed methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints, and created a model for determining the least cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs.
- Co-authored The Delta Report for PG&E and EPRI which examined the targeting of DSM measures to defer the expansion of local distribution facilities.

Education

Stanford University Palo Alto, CA

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M.S., Civil Engineering and Environmental Planning 1987

Stanford University Palo Alto, CA
B.S., Civil Engineering 1986

Citizenship

United States

Refereed Papers

1. *Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," The Energy Journal, 33:1, 207-229.*
2. *Orans, R., C.K. Woo, B. Horii, M. Chait and A. DeBenedictis (2010) "Electricity Pricing for Conservation and Load Shifting," Electricity Journal, 23:3, 7-14.*
3. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*
4. *Woo, C.K., B. Horii, M. Chait and I. Horowitz (2008) "Should a Lower Discount Rate be Used for Evaluating a Tolling Agreement than Used for a Renewable Energy Contract?" Electricity Journal, 21:9, 35-40.*
5. *Woo, C.K., E. Kollman, R. Orans, S. Price and B. Horii (2008) "Now that California Has AMI, What Can the State Do with It?" Energy Policy, 36, 1366-74.*
6. *Baskette, C., B. Horii, E Kollman, and S. Price (2006) "Avoided cost estimation and post reform funding allocation for California's energy efficiency programs," Energy 31, (2006) 1084-1099.*
7. *Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA, 34:1, 70-80.*
8. *Woo, C.K., I. Horowitz, B. Horii and R. Karimov (2004) "The Efficient Frontier for Spot and Forward Purchases: An Application to Electricity," Journal of the Operational Research Society, 55, 1130-1136.*
9. *Woo, C. K., B. Horii and I. Horowitz (2002) "The Hopkinson Tariff Alternative to TOU Rates in the Israel Electric Corporation," Managerial and Decision Economics, 23:9-19.*
10. *Heffner, G., C.K. Woo, B. Horii and D. Lloyd-Zannetti (1998) "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," IEEE Transactions on Power Systems, PE-493-PWRS-012-1997, 13:2, 560-567.*
11. *Chow, R.F., Horii, B., Orans, R. et. al. (1995), Local Integrated Resource Planning of a Large Load Supply System, Canadian Electrical Association.*

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12. *Woo, C.K., R. Orans, B. Horii and P. Chow (1995) "Pareto-Superior Time-of-Use Rate Option for Industrial Firms," Economics Letters, 49, 267-272.*

13. *Pupp, R., C.K.Woo, R. Orans, B. Horii, and G. Heffner (1995), "Load Research and Integrated Local T&D Planning," Energy - The International Journal, 20:2, 89-94.*

14. *Woo, C.K., D. Lloyd-Zannetti, R. Orans, B. Horii and G. Heffner (1995) "Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation," The Energy Journal, 16:2, 111-130.*

15. *Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994), "Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," Energy - The International Journal, 19:12, 1213-1218.*

16. *Woo, C.K., B. Hobbs, Orans, R. Pupp and B. Horii (1994), "Emission Costs, Customer Bypass and Efficient Pricing of Electricity," Energy Journal, 15:3, 43-54.*

17. *Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," Managerial and Decision Economics, 15, 169-175.*

Research Reports and Filed Testimony

1. *Horii B., C.K. Woo, E. Kollman and M. Chait (2009) Smart Meter Implementation Business Case, Rate-related Capacity Conservation Estimates - Technical Appendices submitted to B.C. Hydro.*

2. *Horii, B., P. Auclair, E. Cutter, and J. Moore (2006) Local Integrated Resource Planning Study: PG&E's Windsor Area, Report prepared for PG&E.*

3. *Horii, B., R. Orans, A. Olsen, S. Price and J Hirsch (2006) Report on 2006 Update to Avoided Costs and E3 Calculator, Prepared for the California Public Utilities Commission.*

4. *Horii, B., (2005) Joint Utility Report Summarizing Workshops on Avoided Costs Inputs and the E3 Calculator, Primary author of testimony filed before the California Public Utilities Commission.*

5. *Horii, B., R. Orans, and E. Cutter (2005) HELCO Residential Rate Design Investigation, Report prepared for Hawaiian Electric and Light Company.*

6. *Orans, R., C.K. Woo, and B. Horii (2004-2005) PG&E Generation Marginal Costs, Direct and rebuttal testimonies submitted to the California Public Utilities Commission on behalf of PG&E.*

7. *Orans, R., C.K. Woo, B. Horii, S. Price, A. Olson, C. Baskette, and J Swisher (2004) Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, Report prepared for the California Public Utilities Commission.*
8. *Orans, R, B. Horii, A. Olson, M. Kin, (2004) Electric Reliability Primer, Report prepared for B.C. Hydro and Power Authority.*

9. *Horii, B., T. Chu (2004) Long-Run Incremental Cost Update – 2006/2005, Report prepared for B.C. Hydro and Power Authority.*

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10. *Price, S., B. Horii (2001) Chelsea and E. 13th Street / East River Evaluation, Local integrated resource planning study prepared for Consolidated Edison Company of New York.*

11. *Horii, B., C.K. Woo, and S. Price (2001) Local Integrated Resource Planning Study for the North of San Mateo Study Area, Report prepared for PG&E.*

12. *Horii, B., C.K. Woo and D. Engel (2000) PY2001 Public Purpose Program Strategy and Filing Assistance: (a) A New Methodology for Cost-Effectiveness Evaluation; (b) Peak Benefit Evaluation; (c) Screening Methodology for Customer Energy Management Programs; and (d) Should California Ratepayers Fund Programs that Promote Consumer Purchases of Cost-Effective Energy Efficient Goods and Services? Reports submitted to Pacific Gas and Electric Company.*

13. *Horii, B. (2000) Small Area Forecasting Process and Documentation, Report prepared for Puget Sound Energy Company.*

14. *Price S., B. Horii, and K. Knapp (2000) Rainey to East 75th Project – Distributed Resource Screening Study, Report prepared for Consolidated Edison Company of New York.*

15. *Mahone, D., J. McHugh, B. Horii, S. Price, C. Eley, and B. Wilcox (1999) Dollar-Based Performance Standards for Building Energy Efficiency, Report submitted to PG&E for the California Energy Commission.*

16. *Horii, B., J. Martin (1999) Report to the Alaska Legislature on Restructuring, E3 prepared the forecasts of market prices and stakeholder impacts used in this CH2M Hill report.*

17. *Horii, B., S. Price, G. Ball, R. Dugan (1999) Local Integrated Resource Planning Study for PG&E's Tri-Valley Area, Report prepared for PG&E.*

18. *Woo, C.K. and B. Horii (1999) Should Israel Electric Corporation (IEC) Replace Its Industrial Time of Use Energy Rates with A Hopkinson Tariff? Report prepared for IEC.*
19. *B. Horii, J. Martin, Khoa Hoang, (1996), Capacity Costing Spreadsheet: Application of Incremental Costs to Local Investment Plans, Report and software forthcoming from the Electric Power Research Institute.*

20. *Lloyd-Zanetti, D., B. Horii, J. Martin, S. Price, and C.K. Woo (1996), Profitability Primer: A Guide to Profitability Analysis in the Electric Power Industry, Report No. TR-106569, Electric Power Research Institute.*

21. *Horii B., (1996) Customer Reclassification Study, Report Submitted to Ontario Hydro.*

22. *Horii, B., Orans, R., Woo, C.K., (1995) Area- and Time- Specific Marginal Cost and Targeted DSM Study, Report submitted to PSI Energy.*

23. *Horii, B., Orans, R., Woo, C.K., (1995) Local Integrated Resource Planning Study - White Rock, Report submitted to B.C. Hydro.*

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24. *Horii, B., Orans, R., Woo, C.K., (1995) Area- and Time- Specific Marginal Cost Study, Report submitted to B.C. Hydro.*
25. *Orans, R., C.K. Woo and B. Horii (1995), Impact of Market Structure and Pricing Options on Customers' Bills, Report submitted to B.C. Hydro.*

26. *Horii, B., R. Orans (1995), System Incremental Cost Study 1994 Update (With Regional Results Appendix), Report submitted to B.C. Hydro.*

27. *Horii, B., Orans, R., Woo, C.K., (1994) Marginal Cost Disaggregation Study, Report submitted to PSI Energy.*

28. *Orans, R., C.K. Woo, J.N. Swisher, B. Wiersma and B. Horii (1992), Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District, Report No. TR-100487, Electric Power Research Institute.*

29. *Horii, B., (1991) Pacific Gas and Electric Company 1993 General Rate Case Application (eight exhibits within Phase I, and contributions to five exhibits within Phase II), A. 91-11-036, Submitted to the California Public Utilities Commission.*

30. *Horii, B., (1991) Pacific Gas and Electric Company 1991 Electricity Cost Adjustment Clause Application (Revenue Allocation and Rate Design), Submitted to the California Public Utilities Commission.*

Conference Papers

1. *Heffner, G., C.K. Woo, B. Horii and D. Lloyd-Zannetti (1998) "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," IEEE Transactions on Power Systems, PE-493-PWRS-012-1997, 13:2, 560-567.*

2. *Horii, B., (1995), "Final Results for the NMPC Area Costing and Distributed Resource Study," Proceedings Distributed Resources 1995: EPRI's First Annual Distributed Resources Conference, Electric Research Power Institute, August 29-31, 1995, Kansas City, Missouri*

3. *Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.*

4. *Heffner, G., R. Orans, C.K. Woo, B. Horii and R. Pupp (1993), "Estimating Area Load and DSM Impact by Customer Class and End-Use," Western Load Research Association Conference, September 22-24, San Diego, California; and Electric Power Research Institute CEED Conference, October 27-29, St. Louis, Missouri.*

ROA 1668

Office of Regulatory Staff
Utility Services Request #6
South Carolina Electric & Gas Company
Docket No. 2018-2-E

Utility Services Request #6

ORS AUDIT REQUEST FORM

DATE: March 30, 2018

TO: Paulette Ledbetter/Byron Hinson

UTILITY: South Carolina Electric & Gas
Docket No. 2018-2-E
SCE&G Fuel Adjustment Clause

FROM: Sarah Johnson

AUDIT PURPOSE: Rebuttal testimony of SCE&G witness Joseph Lynch

REQUEST THE FOLLOWING ITEMS BE PROVIDED BY: Noon on April 2, 2018

Provide the response for the following in electronic format and post to the e-room:

1) Provide the workpapers in working Excel format with all formulas intact showing the calculations of the values shown in the table starting on line 8 of page 5.
2) On page 8 lines 19 through 21, SCE&G refers to reserve margins calculated using the LOLE methodology in 2013-2017.
    a. Were LOLE's estimated separately for the summer and winter in any of those studies?
    b. If so, what are the summer and winter LOLE-based reserve margins from those studies?
3) On page 4, SCE&G shows a table of the difference in summer and winter need. The first inputs in the table are summer and winter peak demand that are consistent the IRP table in Exhibit JML-1. Provide workpapers in working Excel format with all formulas intact and explanations of the methods and inputs used to produce the peak demand forecast shown in lines 1 through 3. At a minimum, the response should address the following questions:
    a. Is the forecast based on a top-down econometric model, or bottoms-up end use models, or some other method?
    b. How does weather affect the forecast? Are specific weather conditions assumed for each season or end use? (e.g.: 1-in-10 weather, 1-in-2 weather, a specific design temperature) If so, what are the weather assumptions?

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c. How are load reductions from demand response or curtailable load events treated in the forecast and forecast process? (e.g.: is demand response added back to loads to reconstitute "normal" demand before estimating any econometric models? Are demand response loads somehow added back to the forecast after any econometric forecast is estimated?)

d. How do historical peak loads affect the forecast? (e.g.: does the forecast apply a growth rate to some average peak demand?)

e. If econometric models are used, what dummy variables are included in the model, and what are the assumed values of those variables for the peak forecast? In particular, if a dummy variable for month of the year is used, what month is assumed for the forecast?

4) On page 16, SCE&G discusses the availability of demand response programs that can be employed on peak days. Regarding demand response, provide the following:

   a. A list of all demand response event days, the called amount of load reduction, and the estimated attained amount of reduction for each event. This should be provided going back to Jan 1, 2014.

   b. An explanation of how demand response has been treated in the 2017 Reserve Margin Study. The discussion should at a minimum address:

      i. Do the historical loads used to create the regression models reflect loads with or without demand response reductions?

         1. If the loads reflect the absence of a demand response program, provide workpapers in working Excel format showing the adjustment from recorded load to reconstituted load without the demand response.

5) The IRP table in JML-1 shows forecasted demand response on line 6. Demand response that is achieved during an event is generally less than the amount of subscribed demand response.

   a. Is this demand response in SCE&G's forecast an expected or subscribed amount?

TO: _____ **DATE:** _____

THE REQUESTED ANSWERS, RECORD OR DOCUMENTATION:

1) ☐ **HAS BEEN PROVIDED TODAY;**
2) ☐ **CANNOT BE PROVIDED BY THE REQUESTED DATE, BUT WILL BE MADE AVAILABLE BY** _____;
3) ☐ **ITEM(S)** _____ **IS (ARE) PROPRIETARY AND CONFIDENTIAL BUSINESS INFORMATION;**
4) ☐ **THE ITEM WILL NOT BE PROVIDED. (SEE ATTACHED MEMORANDUM).**

_____

SIGNATURE & TITLE OF RESPONDENT

ACCEPTED FOR PROCESSING - 2018 March 28 1:55 PM - SCPSC - 2018-2-E - Page 1 of 1

Duke, Daphne

From: BURGESS, KENNETH CHAD [mailto:chad.burgess@scana.com]
Sent: Monday, March 26, 2018 3:21 PM
To: Butler, David <David.Butler@psc.sc.gov>; Benjamin Mustian <bmustian@willoughbyhoefer.com>; Bateman, Andrew <abateman@regstaff.sc.gov>; Pittman, Jenny <jpittman@regstaff.sc.gov>; alex@shissiaslawfirm.com; Richard Whitt <rlwhitt@austinrogerspa.com>; tfrogers@austinrogerspa.com; Richard Whitt <rlwhitt@austinrogerspa.com>; Scott Elliott <selliott@elliottlaw.us>; Bholman@selcsc.org; Matthew Gissendanner <matthew.gissendanner@scana.com>; Mitch Willoughby <mwilloughby@willoughbyhoefer.com>
Subject: RE: DN 2018-2-E - Two Outstanding Motions

David –

SCE&G will be filing a response to the motion filed by the South Carolina Business Alliance in Docket No. 2018-2-E. According to our calculations, SCE&G's response is due April 2, 2018.

With respect to the Petition of SCCCL and SACE, SCE&G will file a response to the Petition; however, the Petition was filed in Docket No. 2017-2-E and not Docket No. 2018-2-E. By making the filing in the 2017 docket, SCE&G did not interpret the Petition to be an issue in the 2018 docket. Additionally, with SCCCL and SACE styling their legal document as a Petition, Commission Regulation 103-830(B), allows SCE&G thirty (30) days to file a response after service by the Chief Clerk. SCE&G has not yet been served with a copy of the Petition.

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

Chad

From: Butler, David <David.Butler@psc.sc.gov>
Sent: Monday, March 26, 2018 2:01 PM
To: BURGESS, KENNETH CHAD <chad.burgess@scana.com>; Benjamin Mustian <bmustian@willoughbyhoefer.com>; Bateman, Andrew <abateman@regstaff.sc.gov>; Pittman, Jenny <jpittman@regstaff.sc.gov>; alex@shissiaslawfirm.com; Richard Whitt <rlwhitt@austinrogerspa.com>; tfrogers@austinrogerspa.com; Richard Whitt <rlwhitt@austinrogerspa.com>; Scott Elliott <selliott@elliottlaw.us>; Bholman@selcsc.org
Subject: DN 2018-2-E - Two Outstanding Motions

***This is an EXTERNAL email from "Butler, David" (David.Butler@psc.sc.gov). Please do not click on a link or open any attachments unless you are confident it is from a trusted source.

To the Parties:
We are going to have an outstanding Petition and an outstanding Motion in this Docket, one of which I have seen and one of which I have not. And these are:

1. A Petition by SCCCL and SACE for an Order requiring that SCE&G comply with Commission Order No. 2018-55 (which I have seen);
2. A Motion by the South Carolina Solar Business Alliance and/or Southern Current to bifurcate the fuel hearing (which I have not seen);

Do some of the parties in this Docket intend to file responses to these documents? I am just checking.
Thanks,
David Butler
Standing Hearing Officer

ACCEPTED FOR PROCESSING - 2018 March 28 1:57 PM - SCPSC - 2018-2-E - Page 1 of 2

Duke, Daphne

From: Blan Holman [mailto:bholman@selcsc.org]
Sent: Tuesday, March 27, 2018 4:46 PM
To: Butler, David <David.Butler@psc.sc.gov>; K. Chad Burgess <chad.burgess@scana.com>; Benjamin Mustian <bmustian@willoughbyhoefer.com>; Bateman, Andrew <abateman@regstaff.sc.gov>; Pittman, Jenny <jpittman@regstaff.sc.gov>; alex@shissiaslawfirm.com; Richard Whitt <rlwhitt@austinrogerspa.com>; tfrogers@austinrogerspa.com; Scott Elliott <selliott@elliottlaw.us>
Subject: RE: DN 2018-2-E - Two Outstanding Motions

David,

CCL and SACE plan to file a response tomorrow in support of SBA's Motion to Bifurcate.

Regarding the 2017-2-E petition, CCL and SACE served the petition on SCE&G electronically and by first class mail on March 21. CCL and SACE requested expedited treatment by the Commission given the clear overlap with 2018-2-E.

SCE&G cites to Rule 103-830(B)(1)-(2) in seeking service directly from the Clerk and an additional 30 days to respond, but those rule provisions refer specifically to petitions for declaratory orders and petitions for a rule to show cause. CCL and SACE's petition is neither of these and thus should not require service by the Chief Clerk nor a full 30 days for response.

A more expedited schedule is warranted for the petition because the 2017-2-E Commission order at issue directed SCE&G to file updated and Commission-compliant PR-2 rates in the Company's 2018-2-E testimony. SCE&G failed to do this, impairing the ability of parties in the 2018-2-E docket to adequately respond to their proposals. If SCE&G proceeds on its desired schedule of awaiting service from the Clerk and another 30 days to respond, the testimony deadlines and hearing in the 2018-2-E proceeding will have already passed. This is why CCL and SACE requested in the petition that the Commission require SCE&G's compliance with filing the PR-2 updated rates within seven days, so that this issue might be addressed with supplemental testimony before the April 10 hearing in 2018-2-E. If SCE&G needs additional time for a response, then setting a response deadline of Monday, April 2 for both the motion to bifurcate and the 2017-2-E petition would, at a minimum, allow the Commission to rule on the matters before the April 10 hearing in 2018-2-E. Please let me know if the Commission requires something additional from the parties in order to expedite this process, including a motion to expedite if needed.

Notably, if SBA's motion to bifurcate is allowed, that may provide an opportunity for a longer response time from SCE&G on the 2017-2-E petition. If the Commission allows for additional time and opportunity to file supplemental testimony related to SCE&G's PR-2 rate and proposed avoided cost methodology changes, then the request to expedite the petition's consideration may be less urgent.

Blan

Blan Holman
Southern Environmental Law Center
463 King St. - Suite B
Charleston, SC 29403

p. 843 720 5270
www.southernenvironment.org

From: Butler, David [David.Butler@psc.sc.gov]
Sent: Monday, March 26, 2018 2:01 PM
To: K. Chad Burgess; Benjamin Mustian; Bateman, Andrew; Pittman, Jenny; alex@shissiaslawfirm.com; Richard Whitt; tfrogers@austinrogerspa.com; Richard Whitt; Scott Elliott; Blan Holman
Subject: DN 2018-2-E - Two Outstanding Motions
To the Parties:
We are going to have an outstanding Petition and an outstanding Motion in this Docket, one of which I have seen and one of which I have not. And these are:
1. A Petition by SCCCL and SACE for an Order requiring that SCE&G comply with Commission Order No. 2018-55 (which I have seen);
2. A Motion by the South Carolina Solar Business Alliance and/or Southern Current to bifurcate the fuel hearing (which I have not seen);

Do some of the parties in this Docket intend to file responses to these documents? I am just checking.
Thanks,
David Butler
Standing Hearing Officer

ACCEPTED FOR PROCESSING - 2018 March 28 1:57 PM - SCPSC - 2018-2-E - Page 2 of 2

CERTIFICATE OF COUNSEL

The undersigned hereby certifies that the *Record on Appeal* contains all material proposed to be included by any of the parties and not any other material.

Respectfully submitted this the 22nd day of May, 2019.

J. Blanding Holman, IV
S.C. Bar No. 72260
Southern Environmental Law Center
463 King Street, Suite B
Charleston, SC 29403
Telephone: (843) 720-5270
bholman@selcsc.org

Attorney for Appellant