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**AMENDED DIRECT TESTIMONY OF**

**JOSEPH M. LYNCH, Ph.D.**

**ON BEHALF OF**

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**

**DOCKET NO. 2019-2-E**

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Joseph M. Lynch and my business address is 220 Operation Way, Cayce, South Carolina.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by SCANA Services, Inc. as Manager of Resource Planning.

**Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE PLANNING IN YOUR CURRENT POSITION.**

A. I am responsible for managing the department that produces South Carolina Electric & Gas Company's ("SCE&G" or "Company") forecast of energy, peak demand, and revenue. I also am responsible for developing the Company's generation expansion plans and overseeing the Company's load research program.

**Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor of Science degree in mathematics. From the University of South Carolina, I received a Master of Arts degree in mathematics, an MBA, and a Ph.D. in management science and finance. I was employed by SCE&G as Senior Budget Analyst in 1977 to develop econometric models to forecast sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and in 1991, I was promoted to my current position of Manager of Resource Planning.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?**

A. Yes. I have testified on numerous occasions before this Commission.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to present certain analyses which support the development of the resource plan used to calculate SCE&G's avoided costs and update Rates PR-1 and PR-2. The resource plan and the calculation of avoided costs are discussed in the Direct Testimony of Company Witness Mr. James Neely. In



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addition, I discuss the 11 components contained in the net energy metering ("NEM") methodology approved by the Commission in Order No. 2015-194 issued in Docket No. 2014-246-E.

**Q. WHAT ANALYSES ARE YOU PRESENTING?**

A. I will discuss four analyses: 1) the impact of solar power on the need for capacity; 2) SCE&G's peak demand forecast; 3) SCE&G's reserve margin policy; and 4) a Loss of Load Expectation ("LOLE") study.

**<u>CONCERNING SOLAR PROFILES</u>**

**Q. DID SCE&G UPDATE ITS ANALYSIS OF SOLAR PROFILES WHICH WAS PART OF THE 2018 FUEL DOCKET? IF SO, WHAT CHANGES WERE MADE IN THE ANALYSIS?**

A. The updated analysis is contained in the study titled "The Capacity Benefit of Solar QFs 2018 Study" ("Solar Capacity Benefit Study") which is included as Exhibit No. ____ (JML-1). This study is essentially the same as last year except that a composite solar profile was used instead of a single solar profile. The composite solar profile used in the report was the average of the actual generation of 7 single-axis tracking solar farms on the SCE&G system for the latest annual period available at the time which was August 1, 2017, through July 31, 2018.



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**Q. WHAT WERE THE PRIMARY CONCLUSIONS MADE FROM THE SOLAR STUDY?**

A. Consistent with last year's findings, the study again concluded that solar power cannot help to serve the system's winter peaking needs because the system typically peaks early in the morning before sunrise. Additionally, for most non-summer days the system load peaks either before sunrise or after sunset, again providing little or no support for serving daily peaks.

Of course, results are different during the summer season. The study concludes that about 46% of the solar farm nameplate capacity will typically be provided to SCE&G's system during the summer peak. This figure is higher than the 34% derived in last year's study which was not based on a composite solar profile. The 46% rating is based on the average solar output during the five highest summer peak load days. For the balance of summer days, the rating drops to 26%. Therefore, in developing a resource plan, SCE&G will consider 26% of the solar nameplate as a base resource available for the whole summer season with an additional 20% for a total of 46% available on summer peaking days.

**Q. DOES THE UPDATED SOLAR CAPACITY BENEFIT STUDY INCLUDE AN ANALYSIS OF THE NUMBER OF DAYS PER YEAR WHEN THE DAILY PEAK IS UNAFFECTED BY SOLAR POWER?**

A. Yes, the study contains an update to the same analysis made last year. The results are summarized in Table 1 below.



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**Table 1**

| Number of Days By Month When a 100 MW Increment in Solar Has Zero Impact on the Peak Demand | | | | |
|---|---|---|---|---|
| | Total Solar Capacity (in MW) After 100 MW Increment | | | |
| Month | 200 | 500 | 800 | 1000 |
| 1 | 18 | 18 | 20 | 21 |
| 2 | 24 | 24 | 24 | 24 |
| 3 | 21 | 22 | 23 | 23 |
| 4 | 21 | 25 | 26 | 26 |
| 5 | 1 | 8 | 13 | 17 |
| 6 | 0 | 0 | 1 | 1 |
| 7 | 0 | 0 | 0 | 2 |
| 8 | 1 | 2 | 3 | 8 |
| 9 | 1 | 6 | 12 | 13 |
| 10 | 16 | 23 | 25 | 27 |
| 11 | 17 | 19 | 20 | 21 |
| 12 | 19 | 20 | 20 | 21 |

The table demonstrates that, as the amount of solar capacity increases, each increment of solar capacity affects the peak on fewer days. The last increment of 100 MW of solar capacity on the system, going from 900 MW to 1,000 MW of total solar capacity, leaves unaffected 163 daily peaks out of 212 days during the seven months of January through April and October through December. In other words, the last 100 MW increment of solar capacity on the system does not impact peak demand on approximately 77% of the days in those seven months. Even in the summer—when solar capacity affects the daily peak on most days—the last increment of 100 MW of solar capacity affects fewer daily peaks than previous increments.



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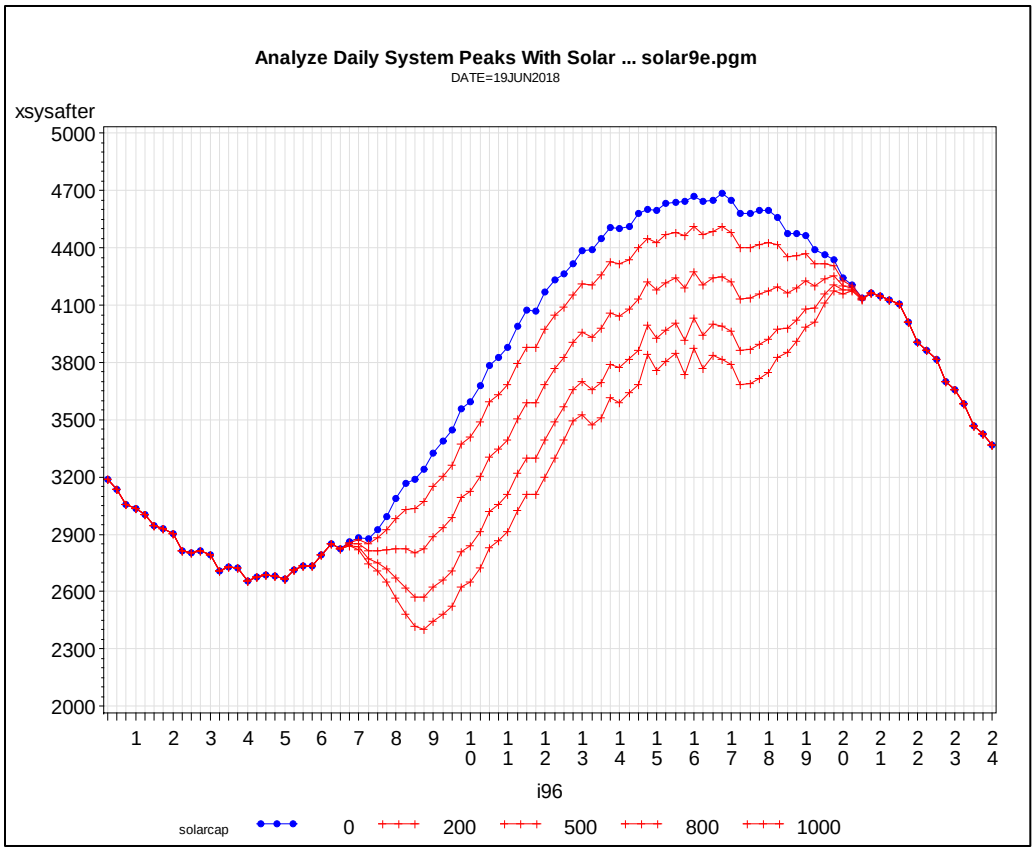
**Q. WHY DOES THE NUMBER OF DAYS WITH SOLAR AFFECTED PEAKS DECREASE AS THE TOTAL AMOUNT OF SOLAR CAPACITY IS ADDED TO THE SYSTEM?**

A. The basic reason is that the time of the system peak can be changed by solar capacity. Particularly in summer, as more and more solar capacity is added to the system the time of the system peak net of the solar output is shifted later and later in the day until it reaches the time of sunset, about 8 p.m., after which adding more solar no longer affects the peak. This can be seen in Chart 1 below which shows the impact of different levels of solar on the day of last summer's system peak. This is more fully discussed in the study attached as Exhibit No. __ (JML-1).

**Chart 1**



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**Q. WHAT IMPACT FROM SOLAR HAS SCE&G SEEN ON RECENT WINTER PEAK DAYS?**

A. Table 2 below shows the time of occurrence of the system peak in the last five winter seasons and only in 2018 has the peak occurred after sunrise allowing a non-zero impact from solar.

**Table 2**

| **Winter Peak Days on SCE&G's System** | | |
|---|---|---|
| Day of Peak | Peak MW | Time of Occurrence |
| January 07, 2014 | 4,717 | 7:30 a.m. |
| February 20, 2015 | 5,035 | 7:00 a.m. |
| January 19, 2016 | 4,451 | 7:00 a.m. |
| January 09, 2017 | 4,493 | 7:15 a.m. |
| January 05, 2018 | 4,776 | 8:00 a.m. |

Table 3 below shows the impact that various amounts of solar would have had during the 2018 winter peak.

**Table 3**

| **Impact of Solar on Peak Day January 5, 2018** | | | | |
|---|---|---|---|---|
| Solar Nameplate Facility Rating (MW) | Peak Load Less Solar Output (MW) | Additional Solar Production at the Peak (MW) | Cumulative Contribution of Solar Production at the Peak (MW) | Time of Effective Peak |
| 0 | 4,776 | | | 8:00 a.m. |
| 200 | 4,770 | 6 | 6 | 8:00 a.m. |
| 500 | 4,762 | 8 | 14 | 7:30 a.m. |
| 800 | 4,762 | 0 | 14 | 7:30 a.m. |
| 1,000 | 4,762 | 0 | 14 | 7:30 a.m. |

Table 3 shows that 500 MW of solar capacity would have only reduced the peak by 14 MW or 2.8% and would shift the peak of the net load to 7:30 a.m. at which time additional solar would have no effect.



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## SCE&G'S PEAK DEMAND FORECAST

**Q. WHAT ARE THE PRINCIPAL RESULTS OF SCE&G'S PEAK DEMAND FORECAST STUDY?**

A. As explained in "The Peak Demand Forecast" study attached as Exhibit No. __(JML-2) the principal results are that SCE&G expects its winter peak demand to be higher than its summer peak demand over the 15-year planning horizon under normal weather conditions. Table 4 below shows the forecasted peaks by season using the industry convention that the winter season follows the summer season.

**Table 4**

| | _Total Internal Demand__ | | _Net Internal Demand__ | | _Demand Response__ | |
|---|---|---|---|---|---|---|
| wyr | Summer | Winter | Summer | Winter | Summer | Winter |
| 2019 | 4,883 | 4,964 | 4,639 | 4,749 | -244 | -215 |
| 2020 | 4,933 | 5,008 | 4,688 | 4,792 | -245 | -216 |
| 2021 | 4,979 | 5,039 | 4,733 | 4,822 | -246 | -217 |
| 2022 | 5,019 | 5,078 | 4,772 | 4,860 | -247 | -218 |
| 2023 | 5,058 | 5,100 | 4,810 | 4,882 | -248 | -218 |
| 2024 | 5,084 | 5,140 | 4,835 | 4,921 | -249 | -219 |
| 2025 | 5,124 | 5,183 | 4,874 | 4,963 | -250 | -220 |
| 2026 | 5,170 | 5,228 | 4,919 | 5,007 | -251 | -221 |
| 2027 | 5,213 | 5,268 | 4,961 | 5,046 | -252 | -222 |
| 2028 | 5,257 | 5,308 | 5,003 | 5,085 | -254 | -223 |
| 2029 | 5,297 | 5,348 | 5,042 | 5,124 | -255 | -224 |
| 2030 | 5,340 | 5,391 | 5,084 | 5,166 | -256 | -225 |
| 2031 | 5,382 | 5,434 | 5,125 | 5,208 | -257 | -226 |
| 2032 | 5,426 | 5,475 | 5,168 | 5,248 | -258 | -227 |
| 2033 | 5,467 | 5,518 | 5,208 | 5,290 | -259 | -228 |
| 2034 | 5,510 | 5,558 | 5,250 | 5,329 | -260 | -229 |
| 2035 | 5,553 | 5,598 | 5,292 | 5,368 | -261 | -230 |
| 2036 | 5,596 | 5,638 | 5,334 | 5,407 | -262 | -231 |
| 2037 | 5,639 | 5,680 | 5,375 | 5,448 | -264 | -232 |

The total internal demand, also referred to as the gross peak, represents the system peak demand before dispatching any demand response ("DR") resources. The net internal demand, also known as the net peak or firm peak demand, represents the peak demand after all DR resources are dispatched. The DR forecast represents the Company's existing DR resources.

**Q. HOW DOES SCE&G FORECAST ITS SEASONAL PEAK DEMANDS?**

A. The details of the forecasting process are explained more fully in the study attached as Exhibit No. __(JML-2) but the basic methodology is to use the customer and energy sales forecast as the driver for growth and to use the load characteristics of each customer class captured in the Company's Load Research Program to develop the resulting peak demand. After this base level of demand is calculated then adjustments are made to the forecast to account for incremental impacts of energy efficiency (both from Company programs and federal mandates) and incremental net energy metering on the system. Table 5 below shows the process to develop the base forecast for the residential, commercial and industrial classes in the next few seasons.

**Table 5**

| **Components in the Base Peak Demand Forecast** | | | | |
|---|---|---|---|---|
| **Season** | **Driver** | **Load Characteristic** | **4-Hour Factor** | **Base Peak Forecast** |
| Residential 2019 Summer | 634,054 Customers | 3.310 kW per Customer | 1.0098 | 2,119 MW |
| Residential 2019/2020 Winter | 643,719 Customers | 3.973 kW per Customer | | 2,558 MW |
| Commercial 2019 Summer | 97,221 Customers | 15.887 kW per Customer | 1.0098 | 1,560 MW |
| Commercial 2019/2020 Winter | 98,116 Customers | 13.856 kW per Customer | | 1,359 MW |
| Industrial 2019 Summer | 5,908.3 GWh | 1.047 kW per kWh | 1.0098 | 713 MW |
| Industrial 2019/2020 Winter | 5,986.2 GWh | 0.904 kW per kWh | | 618 MW |



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The 4-hour factor applied in the summer season converts the forecast for the 4-hour band of hours, i.e., 2 p.m. to 6 p.m., to a one-hour basis. The winter peak does not need the conversion since it is projected on a one-hour basis. The calculation for the residential and commercial classes is straightforward. For example, in the case of the residential 2019 summer, the calculation is:

634,054 * 3.310 *1.0098 = 2,119,286 kW = 2,119 MW

For the industrial class, the number of hours in the year comes into play. For example, in the case of the industrial 2019/2020 winter, the calculation is:

(5,986.2/ (8,760/1,000)) * 0.904 = 618 MW.

It may be worth noting that the kW per kWh load characteristic can be referred to as the demand ratio and is equal to the reciprocal of the load factor.

**Q. WHY DOES SCE&G PROJECT ITS WINTER PEAK TO BE HIGHER THAN ITS SUMMER PEAK?**

A. The prominence of the winter peak demand relative to the summer peak demand is a consequence of changes in customer usage patterns resulting from energy efficiency and conservation having different seasonal impacts. For example, based on the Company's load research studies, the kW per customer impact on the summer peak demand has decreased from about 3.804 kW prior to the Great Recession[1] to about 3.310 kW today while in winter the decrease was from about

[1] The National Bureau of Economic Research ("NBER") sets the dates of the Great Recession as beginning in December 2007 and ending in June 2009. This recession is called "Great" because of the severity of its impact on the world.



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4.132 kW to about 3.973 kW. That's about a 13% decrease in summer and only about a 4% decrease in winter. For the average commercial customer, the decrease is about 10% in summer from 17.724 kW per customer to 15.887 kW and only about 3% in winter from 14.281 kW to 13.856 kW per customer. Obviously, there are more effective opportunities to conserve in summer than winter.

**Q. THE PROJECTED WINTER PEAKS AND SUMMER PEAKS ARE VERY CLOSE. WOULD SIGNIFICANT CHANGES NEED TO BE MADE TO THE ASSUMPTIONS IN THE FORECAST TO PRODUCE A SUMMER PEAK FORECAST GREATER THAN THE WINTER PEAK FORECAST?**

A. No. The summer peak forecast and the winter peak forecast are close. For example, for the 2020 planning year, i.e., with the winter season following the summer, the projected winter peak demand is 104 MW larger than the summer peak and only 61 MW for the calendar year. This difference can easily reverse with a small change in customer load characteristics. For example, if the residential class contributes 3.410 kW per customer instead of 3.310 kW, the summer forecast will increase by about 65 MW while if the winter contribution decreased to 3.873 kW per customer from 3.973 kW then the winter demand would decrease by about 65 MW. Similar what-if calculations can be made for the commercial class. It is not unreasonable to imagine that some of the significant drop in kW per customer contribution observed in the summer for both the residential and commercial classes might reverse in the near future as the economy improves.



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## SCE&G'S RESERVE MARGIN POLICY

**Q. WHAT IS SCE&G'S CURRENT RESERVE MARGIN POLICY USED IN DEVELOPING ITS RESOURCE PLAN?**

A. Table 6 below summarizes SCE&G's reserve margin policy.

**Table 6**
**Minimum Reserve Margin as Percent of Seasonal Peak Demand**

| | SUMMER | WINTER |
|---|---|---|
| Base Level | 12% | 14% |
| Peaking Level | 14% | 21% |
| Increment for Peaking | 2% | 7% |

The Commission accepted these reserve margins in Order No. 2018-322(A).

**Q. HAS SCE&G MODIFIED THE RESERVE MARGIN STUDY PRESENTED IN THE 2018 FUEL DOCKET?**

A. Yes. The updated study titled "2018 Reserve Margin Study" is attached as Exhibit No. __ (JML-3). This study differs from last year in that more analysis is provided to establish the winter and summer peak demand risk related to extreme weather. Last year a single quadratic regression equation, one in each season, was used to estimate the weather risk. Because of this, questions were asked about the appropriateness of using a quadratic formulation and of using all heating or cooling days in the season for regression estimation. To address these questions head on, this year's study developed three separate equations for each season: a quadratic equation using all the heating or cooling days in the season; a quadratic formula

using a restricted number of days; and finally, a linear equation using a restricted number of days.

**Q. WHAT WERE THE RESULTS?**

A. Table 7 below shows the three components that make up the reserve margin, i.e., the VACAR operating reserves, the reserves for the demand-side risk, and the reserves for the supply-side risk.

**Table 7**

| Reserve Margin for Summer and Winter Peak Periods | | |
|---|---|---|
| | **Summer** | **Winter** |
| **VACAR Operating** | **200** | **200** |
| **Demand-Side Risk** | **245** | **556** |
| **Supply-Side Risk** | **234** | **223** |
| **Total Reserve MW** | **679** | **979** |
| **Normal Peak Demand** | **4763** | **4852** |
| **Reserve Margin %** | **14.3%** | **20.2%** |
| **Reserve Margin Policy** | **14%** | **21%** |

The results of the study support the continued use of a 14% minimum reserve margin in summer and 21% in winter.

**Q. WHAT WERE THE ESTIMATES OF DEMAND-SIDE RISK FROM THE DIFFERENT FORMULATIONS OF STATISTICAL ESTIMATION?**

A. Table 8 below shows the estimated demand risk by season based on all three equations.



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**Table 8**

| Demand Risk Related to Extreme Weather (MW) | | |
|---|---|---|
| | **Summer** | **Winter** |
| **Quadratic, All Days** | **245** | **556** |
| **Quadratic, Restricted Days** | **252** | **617** |
| **Linear, Restricted Days** | **292** | **509** |

The results using the quadratic regression model on all heating or cooling days were used to develop SCE&G's reserve margin but clearly the other formulations do not provide a significantly different estimate.

**Q. THE WINTER DEMAND SIDE RISK IS MUCH HIGHER THAN SUMMER. CAN YOU CORROBORATE THAT LEVEL OF RISK IN WINTER?**

A. Yes. SCE&G's demand forecasting methodology and class load characteristics can be used to corroborate this level of risk in the winter. As previously discussed, SCE&G expects residential customers to contribute about 3.973 kW per customer at the time of winter peak demand and commercial customers, 13.856 kW. In 2003 SCE&G experienced a very cold winter and our load research program estimated the residential contribution to peak then to be 4.649 kW per customer and the commercial contribution, 15.391 kW. Table 9 below shows the potential demand risk if next winter is very cold and residential and commercial customers respond similarly to 2003.



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**Table 9**

| 2019 Demand-side Winter Weather Risk | | | | |
|---|---|---|---|---|
| | Customers | 2003 kW per Customer | Normal kW per Customer | Risk Estimate |
| Residential | 643,719 | 4.649 | 3.973 | 435 MW |
| Commercial | 98,116 | 15.391 | 13.856 | 151 MW |
| **Total Demand Risk** | | | | **586 MW** |

The demand-side winter weather risk estimate developed here using load research data of 586 MW is reasonably close to the statistical estimate of 556 MW used in the reserve margin analysis. When presenting the demand forecast, I stated that conservation and energy efficiency seemed to have reduced the residential demand by about 4% and the commercial demand by 3% since the Great Recession. Even if you take this into consideration, the winter demand-side risk used in the reserve margin seems reasonable. Here is that calculation using adjusted load research characteristics:

435 MW *(1.00-0.04) + 151 MW * (1.00-0.03) = 564 MW.

The result of 564 MW is close to the level used of 556 MW.

**<u>CONCERNING SCE&G'S LOSS OF LOAD EXPECTATION STUDY</u>**

**Q. DID SCE&G RELY ON A LOSS OF LOAD EXPECTATION ("LOLE") STUDY TO ESTABLISH ITS RESERVE MARGIN POLICY? IF NOT, WHY PRESENT IT IN THIS DOCKET?**

A. SCE&G has made LOLE calculations for many years and reported the results in its IRPs over those years. However, SCE&G does not rely on LOLE calculations



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to establish its reserve margin policy but has reported them as support of its policy. A formal LOLE study is being presented in this docket and is attached as Exhibit No. __ (JML-4) because LOLE is prevalent in the industry for establishing a reserve margin and a desire for these LOLE calculations was expressed in last year's fuel docket.

**Q. WHAT WAS THE GOAL OF THE LOLE STUDY AND HOW DID SCE&G GO ABOUT CONDUCTING THE STUDY?**

A. The goal of the study was to develop the functional relationship between the LOLE index and the system reserve margin. Once this function was estimated, it would be a simple matter to calculate the level of reserve margin associate with an LOLE=0.1. An LOLE of 0.1 represents an outage expectation of 1 day in 10 years or stated differently, 0.1 days in 1 year, and it is the generally accepted level of risk tolerance in the industry. As described in the attached study, SCE&G analyzed 15 years of load data, normalizing the load data to 2019 forecasted levels and calculating the LOLE associated with each reserve margin in the range of 12 to 25% at 0.5% intervals. The load data was adjusted in two ways making for two LOLE studies. One method of adjustment, "the Peak Method," scaled the daily peaks in 2004 through 2018 to produce seasonal peaks equal to those forecasted for 2019 while the second approach, "the Energy Method," scaled the historical load data so it had the same annual energy as 2019. The two approaches produced similar results.



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**Q. WHAT ARE THE RESULTS OF THE LOLE STUDY AND WHAT DO THEY IMPLY FOR SCE&G'S RESERVE MARGIN POLICY?**

A. For each of the 15 years in the study, the reserve margin producing an LOLE=0.1 for that year was computed. Table 10 below summarizes the results for the two variations of peak load adjustment.

**Table 10**

| Reserve Margin Distributions for LOLE=0.1 for Years 2004-2018 | | | |
|---|---|---|---|
| | Minimum | Median | Maximum |
| Peak Method | 16.6% | 18.2% | 20.5% |
| Energy Method | 14.8% | 17.2% | 21.3% |

For the Peak Method of adjustment, one year produced a minimum value of 16.6% and one year a maximum value of 20.5%. For the Energy Method, the range was 14.8% to 21.3%. Each year was similar in the sense of having the same seasonal peak demands or the same annual energy but dissimilar in that each yearly profile was different as a result of the weather patterns and other conditions occurring in that particular year. Thus, for an LOLE=0.1, these results suggest that the SCE&G system requires a reserve margin between a low value of 14.8% and a high value of 21.3% with an average median value of 17.7%.

Since the LOLE methodology uses all days of the year and the LOLE index is a risk measure for the entire year, it should be compared to SCE&G's base level of reserve margin, i.e., the 14% for winter season and 12% for summer. SCE&G's base reserve margin falls below 17.7% and therefore is riskier than the LOLE standard of 0.1 or one day in 10 years criterion. In fact, using a formula derived in



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Exhibit No. _____(JML-4) relating reserve margin to LOLE index, a 14% reserve margin can be shown to be equivalent to an LOLE=0.3 on SCE&G's system on average. That means a risk level of 3 days in 10 years which is riskier than 1 day in 10 years. However, SCE&G's additional peak reserve resources, which mostly consist of demand response programs, will mitigate some of that added risk.

**Q. CAN THE LOLE METHODOLOGY BE USED TO ADDRESS PEAK DEMAND RISK, THAT IS, RISK FROM DEMAND SPIKES RELATED TO ABNORMAL WEATHER?**

A. No. The LOLE methodology addresses average risk for the entire year and an unacceptable risk level on the peak day can be hidden by the summary result for the year. As shown in Exhibit No.____(JML-4), a simple experiment of adding a spike of 500 MW to the annual peak and computing the LOLE can illustrate the problem. Attached are the results of this experiment.

| **Experiment to Analyze Peak Load Increase and Risk** | | | |
|---|---|---|---|
| | **Peak Load** | **Capacity** | **LOLE** |
| **Step 1: Calculate base value of LOLE** | **4,964** | **5,900** | **0.11235** |
| **Step 2: Add 500 MW to peak day** | **5,464** | **5,900** | **0.23616** |
| **Step 3: Increase Capacity to Restore LOLE** | **5,464** | **6,095** | **0.11234** |

The experiment shows that the combination of a peak load and capacity of 4,964 MW and 5,900 MW is equivalent in terms of LOLE to a combination of peak load and capacity of 5,464 MW and 6,095 MW. The LOLE method therefore suggests that an increase of 195 MW of capacity (=6,095-5,900) is sufficient to offset the



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demand risk created by an additional 500 MW in load (=5,464-4,964) which is clearly unacceptable. In this LOLE experiment every day of the year is a little less risky because of the additional 195 MW of capacity and the sum of the reduced risk as measured by the LOLE index on all these days is sufficient to offset the unacceptable risk remaining on the peak day. The logical conclusion to draw from these results is that, if you are concerned about extreme weather spikes in seasonal peaks, the related risk must be analyzed directly as SCE&G has done in its methodology and not by a method that summarizes risk for the entire year as LOLE does.



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## COMPONENTS OF VALUE FOR NEM DISTRIBUTED ENERGY RESOURCES

**Q. WHAT ARE THE COMPONENTS OF VALUE FOR NEM DISTRIBUTED ENERGY RESOURCES?**

A. By way of its Order No. 2015-194 issued in Docket No. 2014-246-E, the Commission approved the following 11 components of value for NEM Distributed Energy Resources:

**Net Energy Metering Methodology**

1. +/- Avoided Energy
2. +/-Energy Losses/Line Losses
3. +/- Avoided Capacity
4. +/- Ancillary Services
5. +/- T&D Capacity
6. +/- Avoided Criteria Pollutants
7. +/- Avoided $CO_2$ Emission Cost
8. +/- Fuel Hedge
9. +/-Utility Integration & Interconnection Costs
10. +/- Utility Administration Costs
11. +/- Environmental Costs

**= Total Value of NEM Distributed Energy Resources**

In Docket No. 2018-2-E, the Company calculated the value for these components, and, in Order No. 2018-322(A), the Commission determined that those values complied with the NEM Methodology approved by the Commission in Order No. 2015-194. Table 11 below shows the components of value of NEM Distributed Energy Resources approved by the Commission in Order No. 2018-322(A).



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**Table 11**
**Total Value of NEM Distributed Energy Resources ($/kWh)**
**Approved in Order No. 2018-322(A)**

| | Current Period | IRP Planning Horizon (15-Year Levelized) | Components |
|---|---|---|---|
| 1 | $0.03070 | $0.03010 | Avoided Energy Costs |
| 2 | $0 | $0 | Avoided Capacity Costs |
| 3 | $0 | $0 | Ancillary Services |
| 4 | $0 | $0 | T & D Capacity |
| 5 | $0.00008 | $0.00008 | Avoided Criteria Pollutants |
| 6 | $0 | $0 | Avoided $CO_2$ Emission Cost |
| 7 | $0 | $0 | Fuel Hedge |
| 8 | $0 | $0 | Utility Integration & Interconnection Costs |
| 9 | $0 | $0 | Utility Administration Costs |
| 10 | $0 | $0 | Environmental Costs |
| 11 | $0.03078 | $0.03018 | Subtotal |
| 12 | $0.00251 | $0.00246 | Line Losses @ 0.9245 |
| 13 | $0.03329 | $0.03264 | **Total Value of NEM Distributed Energy Resources** |

**Q. HAS SCE&G UPDATED THESE COMPONENTS OF VALUE?**

A. Yes. Table 12 shows the updated components of value for NEM Distributed Energy Resources. Two columns of numbers are shown: one for the current value and one for the value over the IRP planning horizon. The difference between these two columns of numbers represents the future benefits of DER and are subject to recovery under S.C. Code Ann. § 58-40-20(F)(6).



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**Table 12**
**Total Value of NEM Distributed Energy Resources ($/kWh)**

| | Current Period | IRP Planning Horizon (15-Year Levelized) | Components |
|---|---|---|---|
| 1 | $0.02977 | $0.02339 | Avoided Energy Costs |
| 2 | $0 | $0 | Avoided Capacity Costs |
| 3 | $0 | $0 | Ancillary Services |
| 4 | $0 | $0 | T & D Capacity |
| 5 | $0.00003 | $0.00003 | Avoided Criteria Pollutants |
| 6 | $0 | $0 | Avoided $CO_2$ Emission Cost |
| 7 | $0 | $0 | Fuel Hedge |
| 8 | $-0.00396 | $-0.00396 | Utility Integration & Interconnection Costs |
| 9 | $0 | $0 | Utility Administration Costs |
| 10 | $0.00113 | $0.00117 | Environmental Costs |
| 11 | $0.02697 | $0.02063 | Subtotal |
| 12 | $0.00220 | $0.00168 | Line Losses @ 0.9245 |
| 13 | $0.02917 | $0.02231 | **Total Value of NEM Distributed Energy Resources** |

**Q. PLEASE EXPLAIN THE COMPONENTS OF VALUE FOR AVOIDED ENERGY COSTS AND AVOIDED CAPACITY COSTS SHOWN ON LINE NOS. 1 AND 2 OF TABLE 12.**

A. The components of value for avoided energy costs and avoided capacity costs are based on the PURPA avoided cost values previously discussed with one adjustment. The avoided energy costs are adjusted to remove the cost of criteria pollutants and environmental costs, which are then reflected in the components shown on Lines 5 and 10, i.e., Avoided Criteria Pollutants and Environmental Costs.



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**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ANCILLARY SERVICES SHOWN ON LINE NO. 3 OF TABLE 12.**

A. Ancillary services refer to the need to balance the load and generation on the system and include operating reserves, both spinning and non-spinning; frequency regulation; and voltage control. SCE&G expects that the cost of providing these ancillary services will increase with the addition of large amounts of solar energy. SCE&G has assigned a value of zero to ancillary services but will address non-zero costs under the overlapping concept of integration on line 8 of Table 12.

**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR TRANSMISSION AND DISTRIBUTION CAPACITY SHOWN ON LINE NO. 4 OF TABLE 12.**

A. SCE&G's NEM distributed resources do not avoid transmission or distribution capacity and therefore the value of this component is zero. On SCE&G's transmission system, customer-scale NEM resources are distributed across SCE&G's transmission system and have too small of an impact on any transmission circuit to result in avoided transmission capacity. For example, the most impacted substation currently on SCE&G's system is connected to 1,818 kW of solar capacity owned by 257 customers. The impact of an 1,818 kW change in load is much too small to affect the planning of or need for a 115 kV or a 230 kV circuit, which carry loads between 237,000 and 948,000 kW.

On the distribution system, SCE&G's engineers must design a circuit for circumstances that will stress the circuit. In particular, since solar output is



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intermittent during the day and non-existent at night, they must also plan for when the DER is not supplying power. The distribution line must carry the load both when the DER is generating and when it is not because of weather related factors or because DER resources are off line.

**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED CRITERIA POLLUTANTS SHOWN ON LINE NO. 5 OF TABLE 12.**

A. SCE&G associates a positive avoided cost value to criteria pollutants such as $NO_x$ and $SO_2$. The avoided cost of these pollutants typically is included in the Company's avoided energy costs but, as I mentioned previously, these costs have been separated out in this proceeding for reporting purposes.

**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED $CO_2$ POLLUTANTS SHOWN ON LINE NO. 6 OF TABLE 12.**

A. Pursuant to Commission Order No. 2015-194, the component of value for avoided $CO_2$ is set at zero until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions. Currently, there are no state or federal laws or regulations restricting the emission of $CO_2$ pollutants and, therefore, the value for $CO_2$ pollutants is zero.



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**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR FUEL HEDGE SHOWN ON LINE NO. 7 OF TABLE 12.**

A. SCE&G does not hedge fuels for electric generation. Therefore, the value for fuel hedging is zero.

**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY INTEGRATION & INTERCONNECTION COSTS SHOWN ON LINE NO. 8 OF TABLE 12.**

A. SCE&G estimates that the integration costs associated with dispatching the system of generating units and meeting the load reliably with significant solar capacity operating on the system is at least $0.00396 per kWh as set forth in the Direct Testimony of Company Witness Dr. Matthew W. Tanner. Other integration and interconnection costs of NEM Distributed Energy Resources are being collected through a DER rider added to the fuel clause.

**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY ADMINISTRATION COSTS SHOWN ON LINE NO. 9 OF TABLE 12.**

A. At present, the administration costs of NEM Distributed Energy Resources are being collected through a DER rider being added to the fuel clause. Therefore, the value of this component is zero.



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**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ENVIRONMENTAL COSTS SHOWN ON LINE NO. 10 OF TABLE 12.**

A. The component of "Environmental Costs" refers to any appropriate environmentally related costs that were not already included in other net metering methodology components. SCE&G associates a positive avoided cost value to represent the cost of certain environmental materials used in the generation of energy, such as lime and ammonia. The avoided cost of these materials typically is included in the Company's avoided energy costs but, as I mentioned previously, these costs have been separated out in this proceeding for reporting purposes.

**Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ENERGY LOSSES/LINE LOSSES SHOWN ON LINE NO. 11 OF TABLE 12.**

A. When a NEM Distributed Energy Resource serves a customer's load behind their meter or when it puts power onto the distribution system, SCE&G avoids having to generate that specific amount of energy. The Company also avoids the energy required to bring the power to the customer's meter or the distribution system, i.e. the line losses associated with delivering power across the system. The loss factor used for these NEM values represents the cumulative marginal line losses at a residential customer's meter.



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**Q. WHAT IS SCE&G REQUESTING OF THE COMMISSION IN THIS PROCEEDING?**

A. SCE&G respectfully requests that the Commission approve the total value of NEM Distributed Energy Resources.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.



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**Exhibit No. __ (JML-1)**

# The Capacity Benefit of Solar QFs

# 2018 Study

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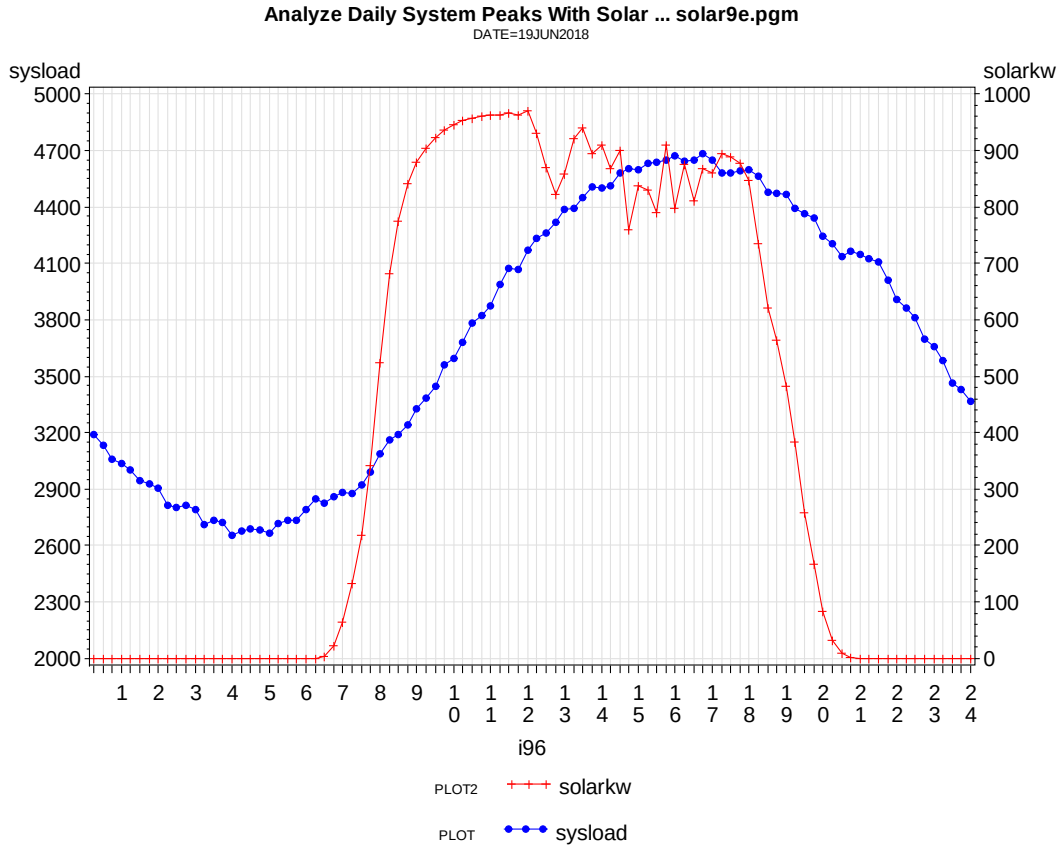
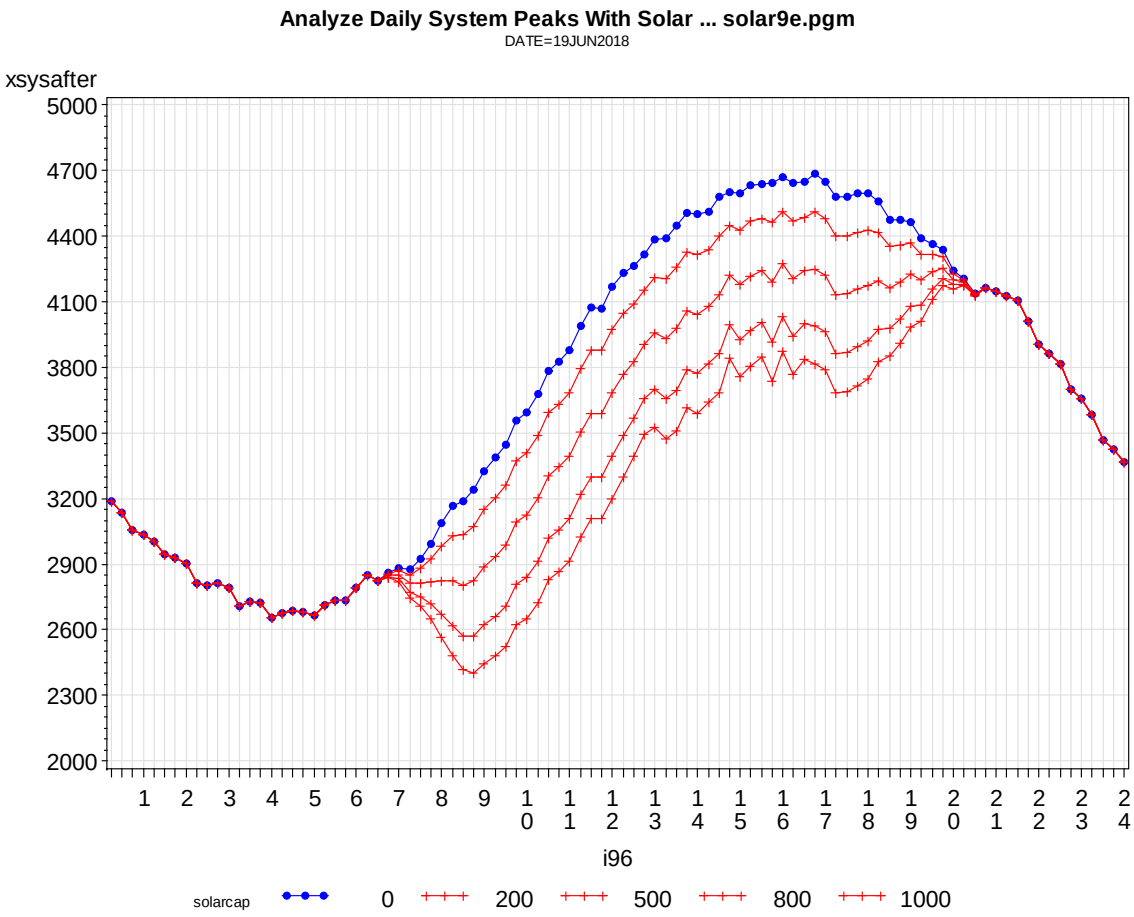
**Introduction:** The following chart compares the system and solar profiles on June 19, 2018, the summer peak day of 2018. The system load is measured on the left vertical axis and the solar on the right. The solar profile used throughout this report is the average of the actual generation of 7 single-axis tracking solar farms on the SCE&G system for the latest annual period available which was August 1, 2017, through July 31, 2018. The solar profile is scaled to a maximum capacity of 1,000 MW 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 7:00 a.m. (0700 hours) until about 8:00 p.m. (2000 hours). The system peak is 4,683 MW occurring at 4:45 p.m. (1645 hours) and by 8:00 p.m. (2000 hours) it decreases to about 4,100 MW 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 about 583 MW (=4,683-4,100). This is because the solar output will be zero at about 8:00 p.m. (2000 hours) and therefore could not reduce the load below 4,100 MW.



The following chart compares the system load without the addition of solar to the system load that results when 200, 500, 800 and 1,000 MW of solar capacity are subtracted from the original system load. Referring to the chart below, the impact of increasing amounts of solar capacity on the system load can be seen visually.




The following Table 1 shows the numerical impact on the peak demand as well as the incremental and cumulative change in peak demand.



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**Table 1**

| Impact of Solar on Peak Day June 19, 2018 | | | | |
|---|---|---|---|---|
| Solar Nameplate Facility Rating (MW) | Peak Load Less Solar Output (MW) | Additional Solar Production at the Peak (MW) | Cumulative Contribution of Solar Production at the Peak (MW) | Time of Effective Peak |
| 0 | 4,683 | | | 4:45 p.m. |
| 200 | 4,512 | 172 | 172 | 4:00 p.m. |
| 500 | 4,272 | 239 | 411 | 4:00 p.m. |
| 800 | 4,205 | 67 | 478 | 7:45 p.m. |
| 1,000 | 4,174 | 32 | 509 | 8:15 p.m. |

For example, the first 200 MW of solar capacity will reduce the peak demand by 172 MW while the last 200 MW, that is, going from 800 to 1,000 MW, will only reduce the peak demand by 32 MW. The change in the time of the peak occurrence helps explain this result. The time of the peak changes from 4:45 p.m. to 8:15 p.m.

A similar discussion can be made for a winter day. The following chart shows the system and solar profile for January 5, 2018, the winter peak day of 2018. It is instructive to note that the solar profile is positive for about 10 hours from about 7:45 a.m. (0745 hours) until about 5:30 p.m. (1730 hours). Since the system peaked at 8:00 a.m. (0800 hours) on this day, the solar impact was modest, only 31 MW. A 1,000 MW solar farm would only change the peak by 14 MW because the time of the peak would change from 8:00 a.m. to 7:30 a.m.



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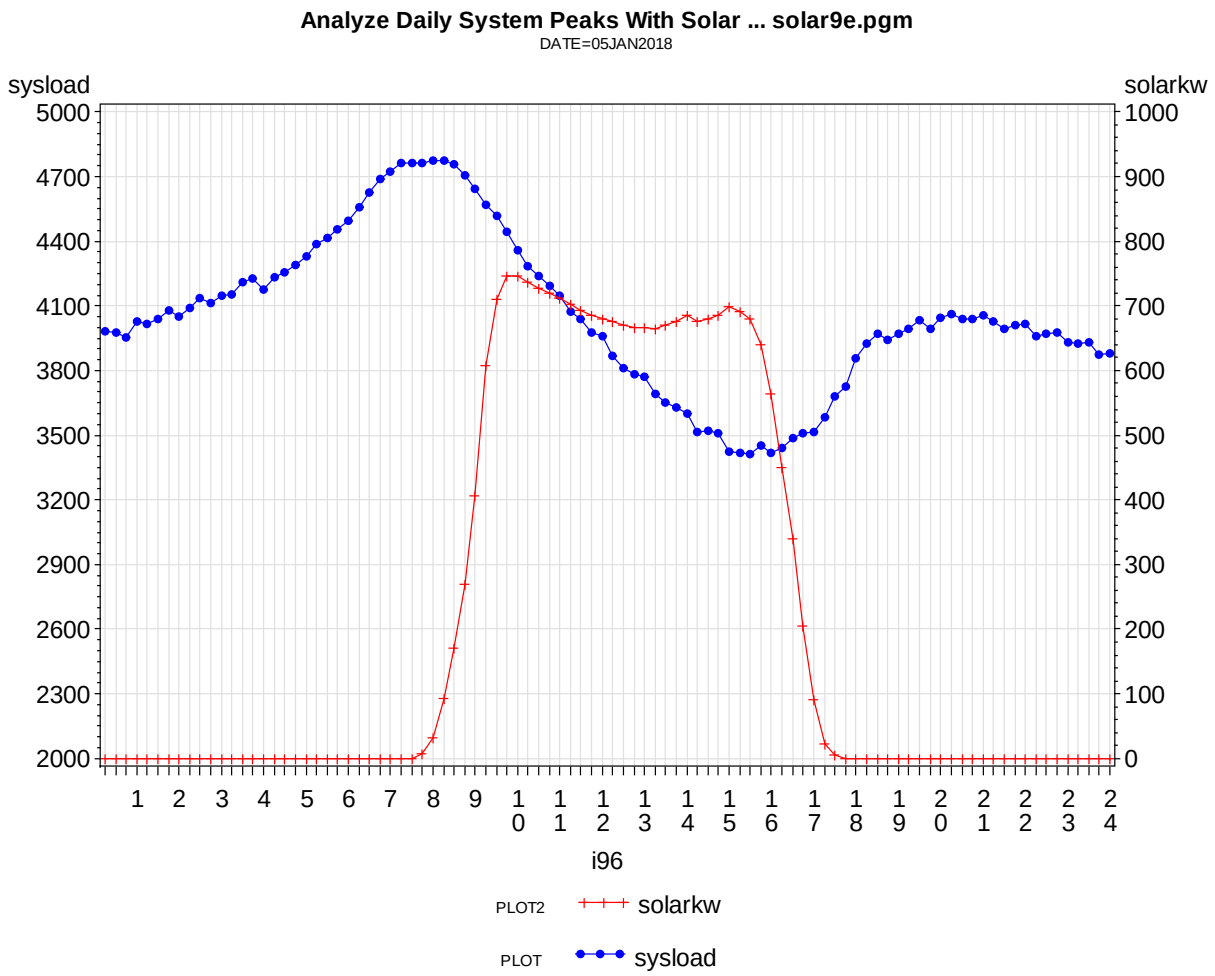


As was shown for the summer peak day, the following chart compares the system load without the addition of solar to the system load that results when 200, 500, 800 and 1,000 MW of solar capacity are subtracted from the original system load.



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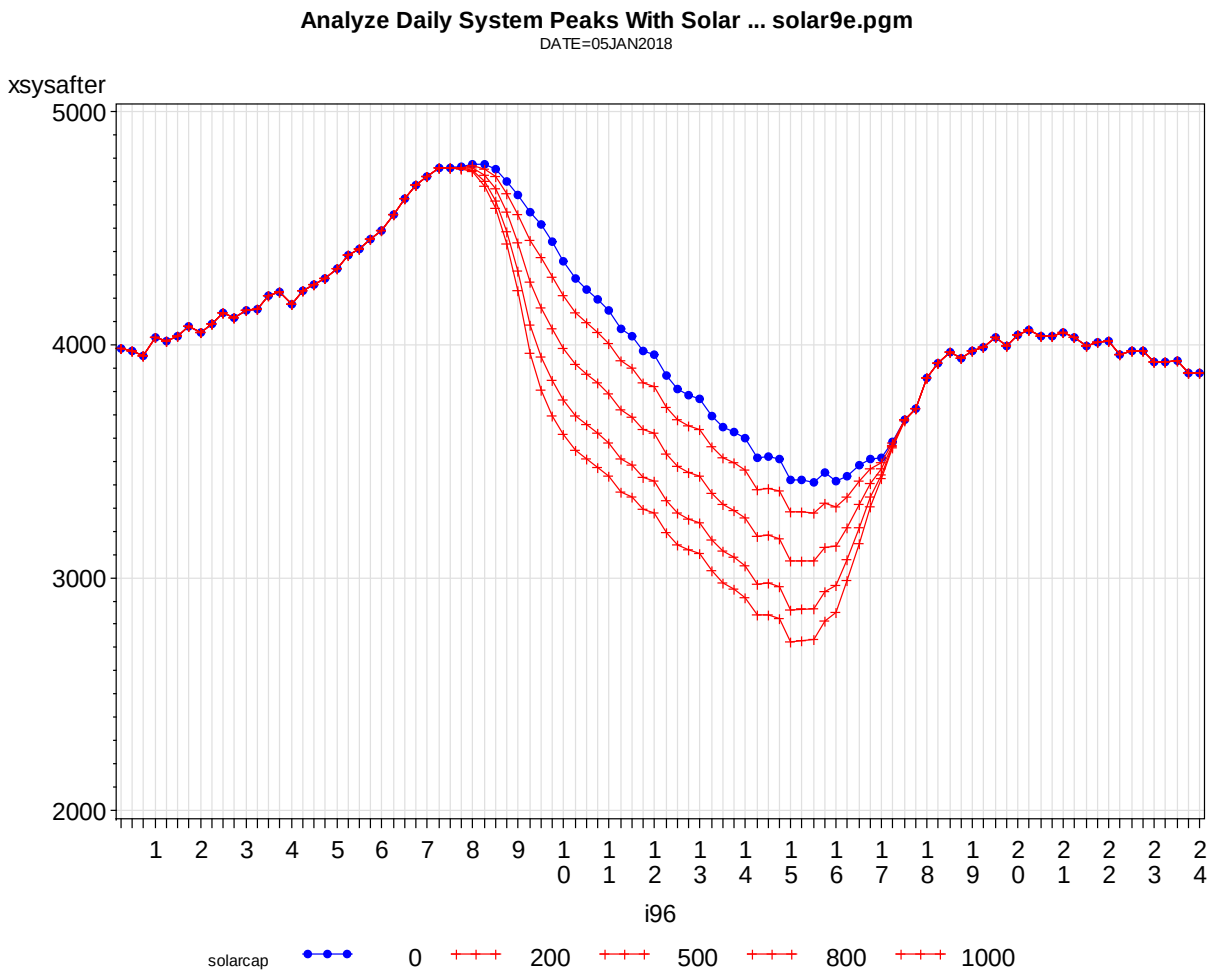


The following Table 2 displays the information in tabular form.

**Table 2**

| Impact of Solar on Peak Day January 5, 2018 | | | | |
|---|---|---|---|---|
| Solar Nameplate Facility Rating (MW) | Peak Load Less Solar Output (MW) | Additional Solar Production at the Peak (MW) | Cumulative Contribution of Solar Production at the Peak (MW) | Time of Effective Peak |
| 0 | 4,776 | | | 8:00 a.m. |
| 200 | 4,770 | 6 | 6 | 8:00 a.m. |
| 500 | 4,762 | 8 | 14 | 7:30 a.m. |
| 800 | 4,762 | 0 | 14 | 7:30 a.m. |
| 1,000 | 4,762 | 0 | 14 | 7:30 a.m. |



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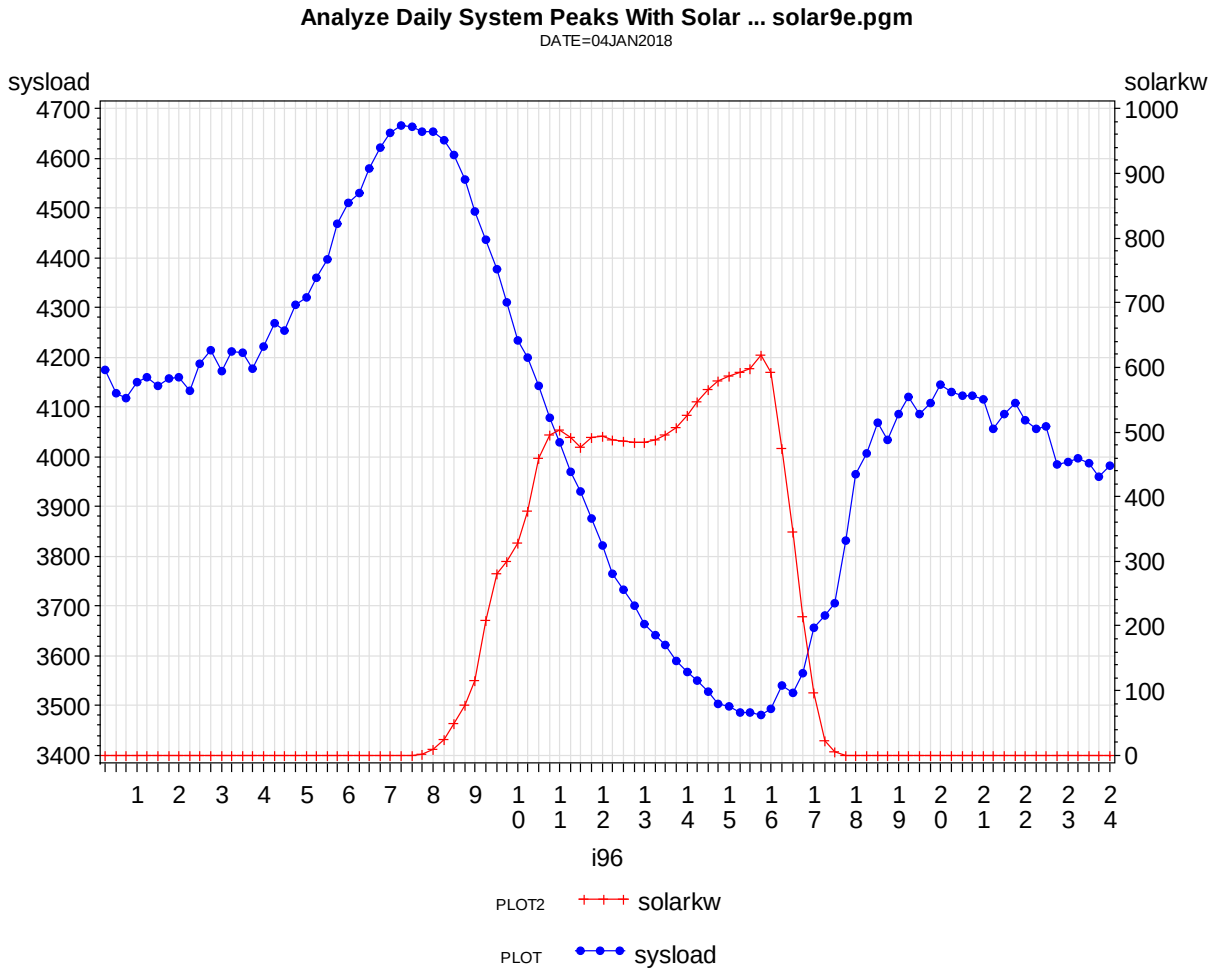
Table 2 shows that the first 500 MW of solar capacity reduces the system peak demand by 14 MW while the next increment of 500 MW has no effect after rounding. To one decimal place the impact is 0.1 MW.

The following chart shows the system and solar profile on the day prior to the peak day, i.e., January 4, 2018. On January 4, 2018, the system peak occurred at 7:30 a.m. when the solar output was zero. Consequently, no matter how much solar is added, even 1,000 MW, there would be no reduction in the system peak on this day.




The following chart shows a day in which the system peaked after sunset. The day is March 20, 2018, and the system peak occurred at 8:15 p.m. when the solar generation was zero.



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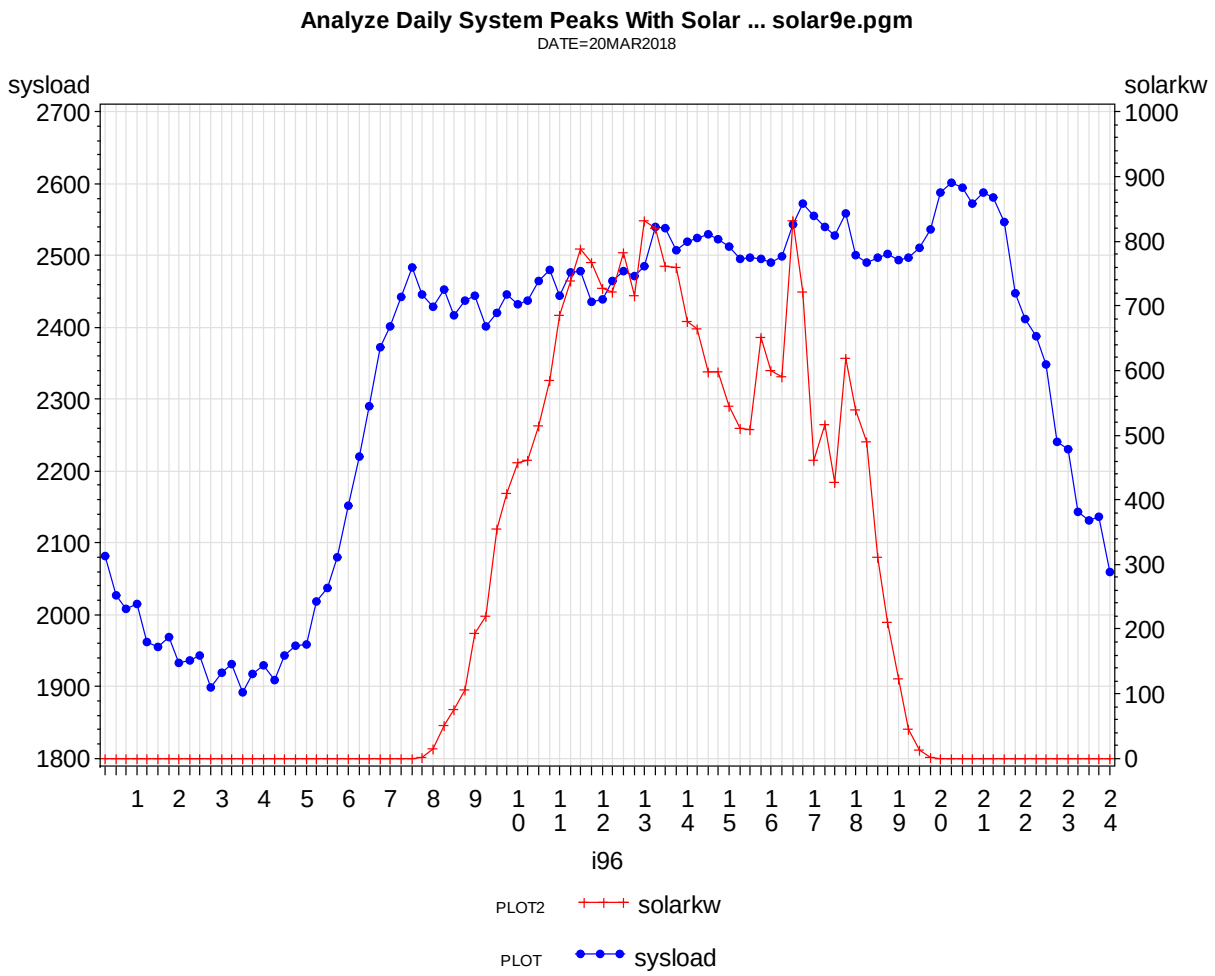


Many winter days are like these winter peak days in that the peak demand occurs either before or after the hours of solar output.

**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 some days the impact of solar on the need for capacity is zero. The Company is interested in the impacts of incremental levels of solar and it has been shown that as more solar capacity is added to the system, the incremental effects decrease. The following Table 3 displays the number of peak days affected by increments of solar in 100 MW steps. For example, if 100 MW of solar are added to SCE&G's system during the period of this study, there would be 18 days in January on which the peak demand is not changed; 24



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days in February, 20 in March, etc. However, if there exists 900 MW of solar already on the system and 100 MW more is added to produce a total of 1,000 MW, this last 100 MW will leave the peak demand unaffected on 21 days in January, 24 days in February, 23 days in March, etc.

**Table 3**

**Number of Days By Month When a 100 MW Increment in Solar Has Zero Impact on the Peak Demand**

| | Amount of Solar Capacity on the System After the 100 MW Increment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | 100 | 200 | 300 | 400 | 500 | 600 | 700 | 800 | 900 | 1000 |
| 1 | 18 | 18 | 18 | 18 | 18 | 18 | 19 | 20 | 20 | 21 |
| 2 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| 3 | 20 | 21 | 21 | 21 | 22 | 22 | 22 | 23 | 23 | 23 |
| 4 | 9 | 21 | 23 | 24 | 25 | 25 | 25 | 26 | 26 | 26 |
| 5 | 0 | 1 | 2 | 6 | 8 | 13 | 13 | 13 | 15 | 17 |
| 6 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 |
| 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| 8 | 0 | 1 | 1 | 1 | 2 | 2 | 2 | 3 | 8 | 8 |
| 9 | 1 | 1 | 2 | 5 | 6 | 10 | 10 | 12 | 13 | 13 |
| 10 | 14 | 16 | 19 | 21 | 23 | 24 | 24 | 25 | 26 | 27 |
| 11 | 15 | 17 | 19 | 19 | 19 | 20 | 20 | 20 | 21 | 21 |
| 12 | 19 | 19 | 19 | 20 | 20 | 20 | 20 | 20 | 20 | 21 |
| Total | 120 | 139 | 148 | 159 | 167 | 178 | 180 | 187 | 197 | 204 |

It appears that for 7 months of the year, solar will not affect the daily peak demand on most of the days of the month. However, for 3 months, i.e., for June through August, solar will impact the peak demand on most days of the month.

**Solar Impact in Winter:** Consideration of the winter months October through April supports the conclusion that solar has zero capacity value in winter. There are 212 days in these 7 months and on 163 of those days, the last 100 MW increment of solar reaching a total of 1,000 MW of solar capacity has no impact on the system peak demand reflecting about a 77% fail ratio.

It is useful to note the time of the system peak demand in the last 5 winter seasons. Table 4 below contains this information.



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**Table 4**

| Winter Peak Days on SCE&G's System | | |
|---|---|---|
| Day of Peak | Peak (MW) | Time of Occurrence |
| January 07, 2014 | 4,717 | 7:30 a.m. |
| February 20, 2015 | 5,035 | 7:00 a.m. |
| January 19, 2016 | 4,451 | 7:00 a.m. |
| January 09, 2017 | 4,493 | 7:15 a.m. |
| January 05, 2018 | 4,776 | 8:00 a.m. |

On the four winter peak days when the peak demand occurred at or before 7:30 a.m., the presence of solar capacity would not have helped serve the peak load. The following Table 5 shows the impact that various amounts of solar would have on the 2018 winter peak.

**Table 5**

| Impact of Solar on Peak Day January 5, 2018 | | | | |
|---|---|---|---|---|
| Solar Nameplate Facility Rating (MW) | Peak Load Less Solar Output (MW) | Additional Solar Production at the Peak (MW) | Cumulative Contribution of Solar Production at the Peak (MW) | Time of Effective Peak |
| 0 | 4,776 | | | 8:00 a.m. |
| 200 | 4,770 | 6 | 6 | 8:00 a.m. |
| 500 | 4,762 | 8 | 14 | 7:30 a.m. |
| 800 | 4,762 | 0 | 14 | 7:30 a.m. |
| 1,000 | 4,762 | 0 | 14 | 7:30 a.m. |

Table 5 shows that 500 MW of solar capacity would have only reduced the peak by 14 MW or 2.8% and would shift the peak of the net load to 7:30 a.m. at which time additional solar would have no effect.

**Solar Impact in Summer:** The tables below show the results of the summer analysis. Table 6 shows the solar impact on the five highest peak days of the summer. For 1,000 MW of solar added to the system, the average daily peak demand is reduced approximately 46% or about 461.6 MW. The last 100 MW of solar capacity, that is, the incremental impact when solar capacity is increased from 900 MW to 1,000 MW, reduces the peak demand by 14.5 MW on average which can also be expressed as 14.5%.

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**Table 6**

| Average Impact of Solar Capacity On 5 Highest Peak Summer Days | | | | |
|---|---|---|---|---|
| Solar Capacity | Nbr Days | Peak Reduction MW | % Reduction | Last 100 MW |
| 0 | 5 | 0.0 | | |
| 100 | 5 | 69.1 | 69% | 69.1 |
| 200 | 5 | 137.6 | 69% | 68.5 |
| 300 | 5 | 204.4 | 68% | 66.8 |
| 400 | 5 | 268.4 | 67% | 64.1 |
| 500 | 5 | 324.8 | 65% | 56.4 |
| 600 | 5 | 361.8 | 60% | 37.0 |
| 700 | 5 | 395.4 | 56% | 33.6 |
| 800 | 5 | 428.2 | 54% | 32.8 |
| 900 | 5 | 447.1 | 50% | 18.9 |
| 1000 | 5 | 461.6 | 46% | 14.5 |

The results of analyzing the solar impact over the remaining days available in the summer season are shown in Table 7 below.

**Table 7**

| Average Impact of Solar Capacity On Most Peak Summer Days | | | | |
|---|---|---|---|---|
| Solar Capacity | Nbr Days | Peak Reduction (MW) | % Reduction | Last 100 MW |
| 0 | 179 | 0.0 | | |
| 100 | 179 | 53.9 | 54% | 53.9 |
| 200 | 179 | 102.5 | 51% | 48.5 |
| 300 | 179 | 144.4 | 48% | 42.0 |
| 400 | 179 | 177.1 | 44% | 32.7 |
| 500 | 179 | 201.2 | 40% | 24.1 |
| 600 | 179 | 219.6 | 37% | 18.4 |
| 700 | 179 | 233.7 | 33% | 14.1 |
| 800 | 179 | 244.5 | 31% | 10.8 |
| 900 | 179 | 253.4 | 28% | 8.9 |
| 1000 | 179 | 261.0 | 26% | 7.6 |

Having 1,000 MW of solar capacity on the system yields an average reduction in peak demand of 26% or 261 MW. On an incremental basis, the impact of the last 100 MW of solar is

7.6 MW on average. The conclusion is that the last 100 MW of capacity will provide about 7.6 MW of system capacity relief for most of the summer season, i.e., during the months of May through October, plus an additional 6.9 MW (=14.9-7.6 MW) on the summer peak day.



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**Exhibit No. __ (JML-2)**

# The Peak Demand Forecast

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## Introduction

The peak demand forecasted growth is determined by the customer and sales forecast using the load characteristics of the different customer classes developed as part of the Company's Load Research Program. This report presents those load characteristics and the resulting peak demand forecast. The methodology for forecasting customers and sales involves many statistical and econometric models, a discussion of which is beyond the scope of this report. However, several comparisons of forecasted to historical growth in customers and sales are included to demonstrate the reasonableness of the forecast.

Table 1 below shows the forecast of the total internal demand, also known as the gross peak demand, for summer and winter. It also shows the projected net internal demand, also known as the firm peak demand, which requires supply resources to serve. The difference between these two demand concepts is the level of demand response currently available to the Company, most of which is comprised of interruptible customer load.

**Table 1**

| | _Total Internal Demand__ | | _Net Internal Demand__ | | _Demand Response__ | |
|---|---|---|---|---|---|---|
| wyr | Summer | Winter | Summer | Winter | Summer | Winter |
| 2019 | 4,883 | 4,964 | 4,639 | 4,749 | -244 | -215 |
| 2020 | 4,933 | 5,008 | 4,688 | 4,792 | -245 | -216 |
| 2021 | 4,979 | 5,039 | 4,733 | 4,822 | -246 | -217 |
| 2022 | 5,019 | 5,078 | 4,772 | 4,860 | -247 | -218 |
| 2023 | 5,058 | 5,100 | 4,810 | 4,882 | -248 | -218 |
| 2024 | 5,084 | 5,140 | 4,835 | 4,921 | -249 | -219 |
| 2025 | 5,124 | 5,183 | 4,874 | 4,963 | -250 | -220 |
| 2026 | 5,170 | 5,228 | 4,919 | 5,007 | -251 | -221 |
| 2027 | 5,213 | 5,268 | 4,961 | 5,046 | -252 | -222 |
| 2028 | 5,257 | 5,308 | 5,003 | 5,085 | -254 | -223 |
| 2029 | 5,297 | 5,348 | 5,042 | 5,124 | -255 | -224 |
| 2030 | 5,340 | 5,391 | 5,084 | 5,166 | -256 | -225 |
| 2031 | 5,382 | 5,434 | 5,125 | 5,208 | -257 | -226 |
| 2032 | 5,426 | 5,475 | 5,168 | 5,248 | -258 | -227 |
| 2033 | 5,467 | 5,518 | 5,208 | 5,290 | -259 | -228 |
| 2034 | 5,510 | 5,558 | 5,250 | 5,329 | -260 | -229 |
| 2035 | 5,553 | 5,598 | 5,292 | 5,368 | -261 | -230 |
| 2036 | 5,596 | 5,638 | 5,334 | 5,407 | -262 | -231 |
| 2037 | 5,639 | 5,680 | 5,375 | 5,448 | -264 | -232 |

The projected growth rates of both the total and net internal demands over the period 2019-2037 is about 0.8%. The winter peak demands are higher than summer in both cases. For the total internal demand, the difference is 81 MW in 2019 and decreases to 41 MW by 2037. For the net internal demand, the difference is 110 MW in 2019 and 73 MW in 2037. It is important to keep in mind that the Company's resource plan calls for an increase in winter demand response which will lower the net internal demand in winter and may cause the net internal demand in summer to be larger than in winter. It is also worthwhile pointing out that the above demands are not reported on a calendar basis. By utility convention, the winter season is thought to follow the summer season. Thus, the winter demands reflect an additional six months of system growth over summer.

### Customer Class Characteristics

Except for the recent past, the Company's summer peak demands have always been larger than the winter seasonal peak demands. By examining the forecast methodology and how the customer load characteristics are used, it will be evident why the winter demands may dominate in the future. The

following Table 2 contains the components used to derive the peak demand forecasts. The residential and commercial classes, i.e., 10.0 and 20.0, are projected using the number of customers in the forecast while the other classes are projected using GWH sales. The adjustments labeled Res.Adj and Com.Adj will be explained later. The entry labeled Ind.Adj or class=30.2 represents expansions planned by certain large customers which have been communicated to our customer representatives.

**Table 2 – Calendar Based Information**

| | | | Energy Forecast | | Summer Peak | | | Winter Peak | |
|---|---|---|---|---|---|---|---|---|---|
| yr | class | desc | Customer | GWH Sales | kW Per | Factor | Peak Demand | kW Per | Peak Demand |
| 2019 | 10.0 | Res | 634,054 | . | 3.310 | 1.0098 | 2,119 | 3.973 | 2,519 |
| | 10.2 | Res.Adj | . | . | . | . | -25 | . | -22 |
| | 20.0 | Com | 97,221 | . | 15.887 | 1.0098 | 1,560 | 13.856 | 1,347 |
| | 20.2 | Com.Adj | . | . | . | . | -3 | . | -3 |
| | 30.0 | Ind | . | 5908.3 | 1.047 | 1.0098 | 713 | 0.904 | 610 |
| | 30.1 | Ind.DR | . | . | . | . | 210 | . | 178 |
| | 30.2 | Ind.Adj | . | . | . | . | 8 | . | -7 |
| | 60.0 | PSL | . | 156.8 | 0.129 | 1.0098 | 2 | 0.157 | 3 |
| | 70.0 | OPA | . | 519.6 | 1.485 | 1.0098 | 89 | 1.232 | 73 |
| | 92.0 | Muni | . | 900.8 | 1.725 | 1.0098 | 179 | 1.722 | 177 |
| | 98.1 | CoUse | . | . | . | . | 31 | . | 32 |
| | 98.5 | DR | . | . | . | . | -244 | . | -214 |
| 2019 | | | . | . | . | . | 4,639 | . | 4,693 |
| 2020 | 10.0 | Res | 643,719 | . | 3.310 | 1.0098 | 2,152 | 3.973 | 2,558 |
| | 10.2 | Res.Adj | . | . | . | . | -29 | . | -32 |
| | 20.0 | Com | 98,116 | . | 15.887 | 1.0098 | 1,574 | 13.856 | 1,359 |
| | 20.2 | Com.Adj | . | . | . | . | -3 | . | -3 |
| | 30.0 | Ind | . | 5986.2 | 1.047 | 1.0098 | 723 | 0.904 | 618 |
| | 30.1 | Ind.DR | . | . | . | . | 211 | . | 179 |
| | 30.2 | Ind.Adj | . | . | . | . | 3 | . | 0 |
| | 60.0 | PSL | . | 157.0 | 0.129 | 1.0098 | 2 | 0.157 | 3 |
| | 70.0 | OPA | . | 519.5 | 1.485 | 1.0098 | 89 | 1.232 | 73 |
| | 92.0 | Muni | . | 901.2 | 1.725 | 1.0098 | 179 | 1.722 | 177 |
| | 98.1 | CoUse | . | . | . | . | 32 | . | 32 |
| | 98.5 | DR | . | . | . | . | -245 | . | -215 |
| 2020 | | | . | . | . | . | 4,688 | . | 4,749 |

Table 1 shows that the summer net internal demand for 2019 is expected to be 4,639 MW which is shown in Table 2 as the sum of several customer components in the column labeled "Peak Demand". The first number in that column is the residential contribution to this total, labeled as class 10.0, and is equal to 2,119 MW. The formula for calculating this result is:

Peak Demand = Number of Customers * kW per customer * factor / 1000
= 634,054 * 3.310 * 1.0098 / 1000
= 2,119 MW

The number of residential customers, 634,054, is the average number for 2019 projected in the customer and sales forecast. The load characteristic of 3.310 kW per customer is the projected contribution to the four-hour (2-6 p.m.) summer system peak demand for the average residential customer. The "factor" is the average ratio of the one-hour summer peak demand to the four-hour average. Because the summer peak demand typically occurs in one of these four hours and the residential and commercial loads vary significantly by hour, the Company has used the four-hour period to conduct cost of service allocation



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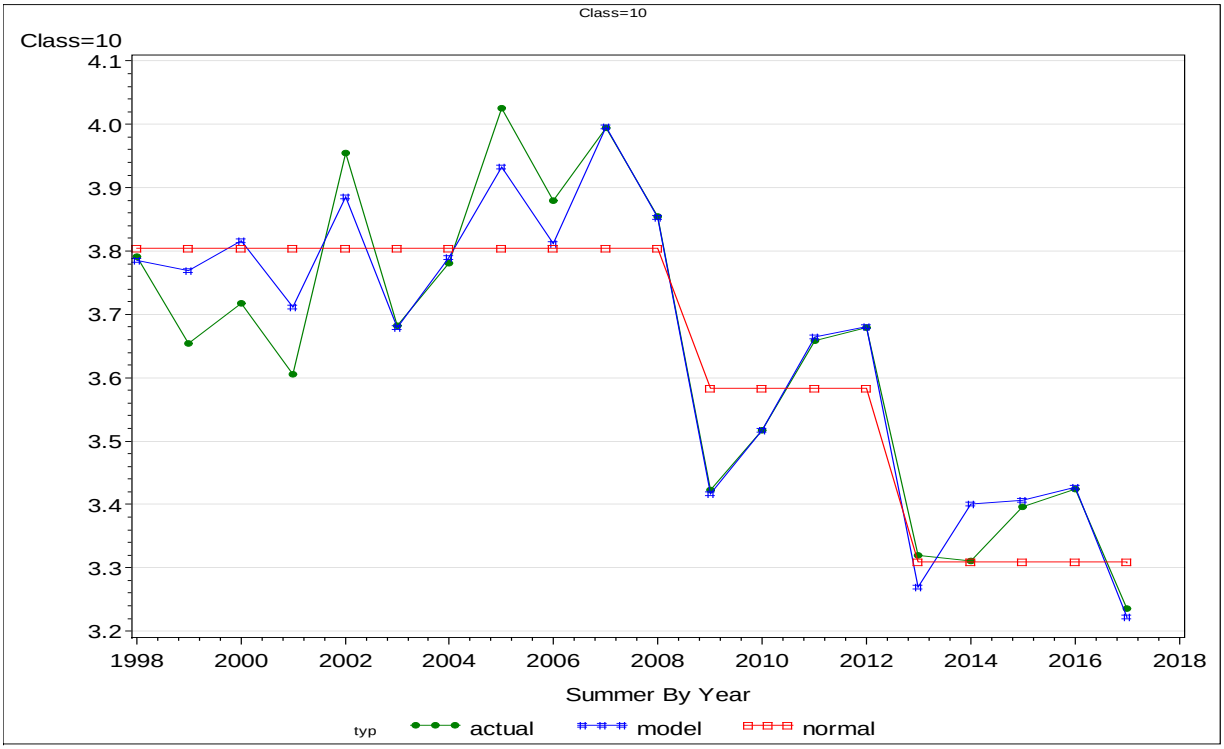
studies for many years. The four-four band is also used to project a more robust summer peak demand which must then be adjusted to the one-hour level, approximately a one percent adjustment.

The following chart shows the derivation of the kW per customer contribution to the summer peak demand for the average residential customer.

**Chart 1**




The chart shows the actual kW per customer going back to 1998 along with a regression model estimate and then a straight-line average based on normal weather. The regression model allows for this average to decrease over time as shown in the graph. The latest average is about 3.310 kW per customer. The average before the Great Recession[1] of 2008 was about 3.804, a 13% decrease.

The development of the winter peak demand forecast for 2019 is similar. As shown in Table 1, the winter net internal demand forecast for 2019 is 4,749 MW. Since the winter season follows the summer season, the components of the 2019 winter forecast must be taken from 2020 of Table 2 which reflects a calendar year. In Table 2 the peak demand of 4,749 MW is shown as the sum of several components and one of those components, labeled class 10.0, is the residential contribution of 2,558 MW. The formula for calculating this result is:

Peak Demand = Number of Customers * kW per customer / 1000
= 643,719 * 3.973 / 1000

[1] The National Bureau of Economic Research ("NBER") sets the dates of the Great Recession as beginning in December 2007 and ending in June 2009. This recession is called "Great" because of the severity of its impact on the world.



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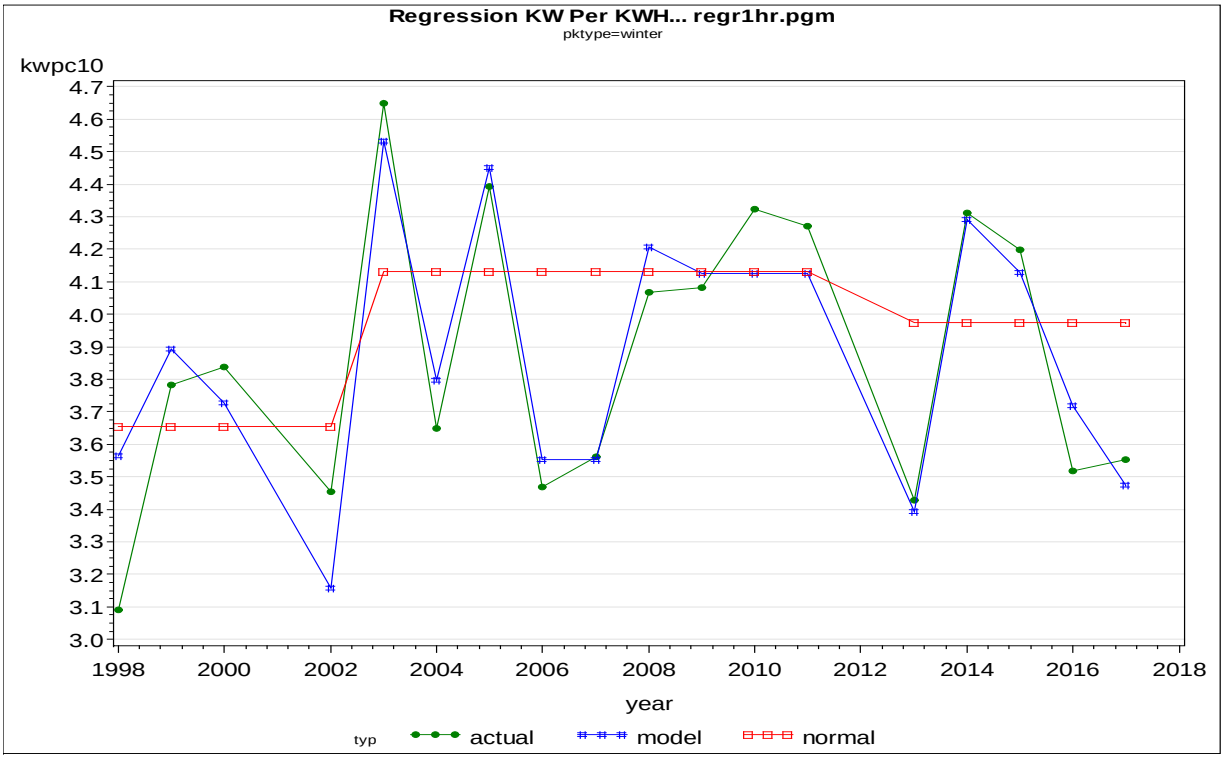
= 2,558 MW

The following chart shows the derivation of the kw per customer contribution to the winter peak demand for the average residential customer.

**Chart 2**




The current estimate of kW per customer of 3.973 reflects a small decrease from a previous period which reaches back to the pre-great recession years. The decrease from 4.132 kW per customer represents only a 3.8% decrease. It is worth noting that the largest kW per customer estimated in the Load Research Program was 4.649 kW per customer occurring in 2003. If circumstances, such as weather, resulted in the 643,719 residential customers increasing their demand from 3.973 to this maximum value of 4.649, it would mean an increase of 435 MW to their peak contribution, i.e. 643,719*(4.649-3.973).

The development of the commercial demand forecasts is identical to residential since it too relies on the number of customers. In winter then, the normal weather estimate of kW per customer contribution to peak is 13.856 and with a customer forecast for 2020 of 98,116 customers, the estimate of commercial class peak contribution in 2019 is 1,359 MW (=98,116*13.856). Remember the 2019 winter season follows the 2019 summer season. The actual kW per customer contribution to the winter peak in 2003 was 15.391. So, if weather like 2003 occurs during the 2019/2020 winter season, the commercial contribution to peak could increase by 151 MW (=98,116*(15.391-13.856)). Combining the commercial and residential demand related weather risk yields a combined weather risk of 586 MW. The following Table 3 summarizes the results.



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**Table 3**

| 2019 Combined Residential and Commercial Demand-side Winter Weather Risk | | | | |
|---|---|---|---|---|
| | Customers | 2003 kW per Customer | Normal kW per Customer | Risk Estimate |
| Residential | 643,719 | 4.649 | 3.973 | 435 MW |
| Commercial | 98,116 | 15.391 | 13.856 | 151 MW |

The industrial demand forecast relies on GWH sales, so it may be useful to review its formula. As already noted, the winter net internal demand for 2019 shown in Table 1 is 4,749 MW and this corresponds to the same number in Table 2 shown for 2020 as the sum of several components. The industrial contribution to this total, 618 MW, appears in the middle of the list of components and is labeled as class = "30.0 Ind". The formula for calculating the industrial demand forecast is:

Peak Demand = (GWH Sales / number of hours) * kW per Average kWh
= (5,986.2 / 8.760) * 0.904
= 618 MW

The 618 MW represents the firm part of industrial load. The non-firm portion or interruptible part is 179 MW and is shown in Table 2 with the label "Ind.DR" or class=30.1. The interruptible load is estimated using load research interval data for those customers participating in the Company's interruptible program. The total industrial winter peak demand, firm plus interruptible, is 797 MW.

The following chart shows the derivation of the kw per customer contribution to the winter peak demand for the average residential customer.



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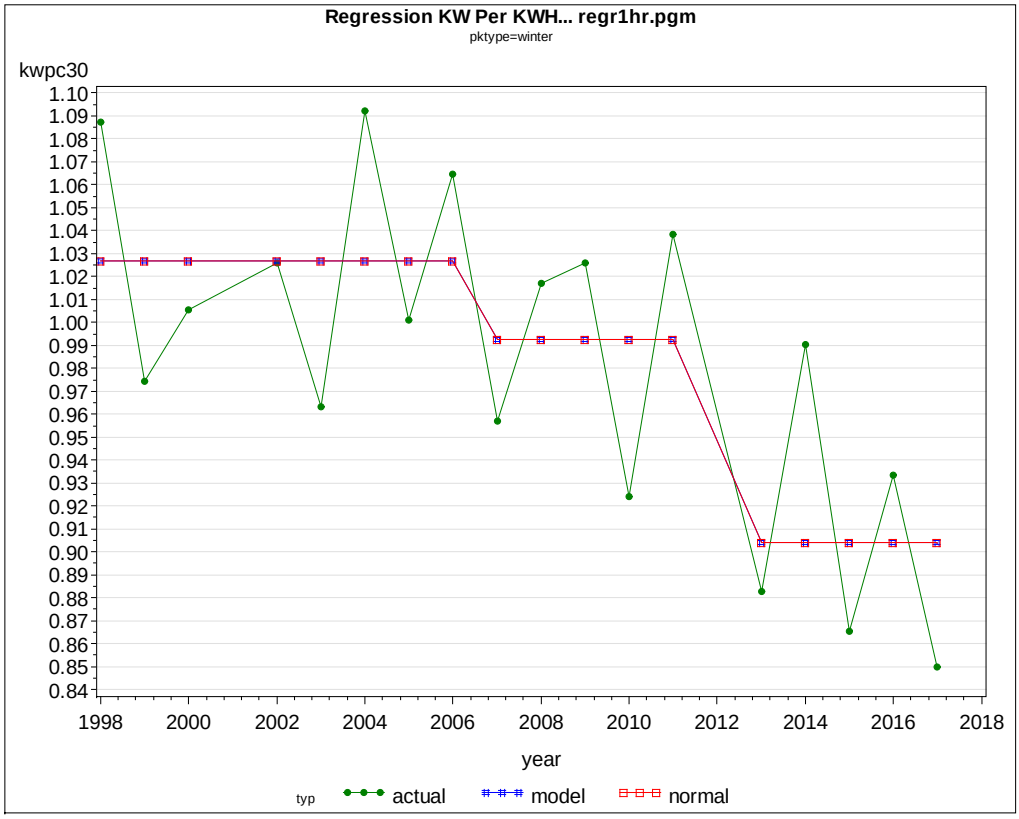
**Chart 3**




Since the industrial load does not vary with weather, the model and normal estimates are the same in the chart.

Calculations like those above were made for each class of customer, each season and each year to produce the forecast. The appendix contains charts for each customer class and season as well as a table like Table 2 for the years 2020, 2025 and 2030.

**Detail Components of Peak Demand Forecast**

The following Table 4 shows all the components that comprise the summer peak demand forecast. The rows labeled 10.5, 10.6, 10.7, 10.8 and 10.9 comprise the amount of load grouped under the label “Res.Adj” earlier in Table 2. The rows labeled 20.6 and 20.7 comprise “Com.Adj”.



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## Table 4 - SUMMER PEAK DEMAND FORECAST

| class | desc | iord | _2019 | _2020 | _2021 | _2022 | _2023 | _2024 | _2025 | _2026 |
|---|---|---|---|---|---|---|---|---|---|---|
| 10.0 | Residential | 1 | 2,119 | 2,152 | 2,186 | 2,216 | 2,244 | 2,271 | 2,299 | 2,328 |
| 10.5 | Res SEER | 5 | -9 | -10 | -11 | -13 | -15 | -33 | -37 | -41 |
| 10.6 | Res Eff Lites | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10.7 | Res SCE&G EE | 7 | 0 | 0 | -6 | -12 | -18 | -24 | -30 | -36 |
| 10.8 | Res Water Heater Eff. | 8 | 0 | 0 | -1 | -1 | -1 | -1 | -1 | -1 |
| 10.9 | Res NEM Solar PV | 9 | -16 | -19 | -20 | -21 | -21 | -21 | -21 | -21 |
| 20.0 | Commercial | 10 | 1,560 | 1,574 | 1,596 | 1,616 | 1,635 | 1,655 | 1,674 | 1,694 |
| 20.5 | Com Standby Gen | 11 | -11 | -11 | -11 | -11 | -11 | -11 | -11 | -11 |
| 20.6 | Com Eff Lites | 12 | -3 | -3 | -10 | -19 | -27 | -32 | -36 | -39 |
| 20.7 | Com SCE&G EE | 13 | 0 | 0 | -1 | -2 | -4 | -5 | -6 | -7 |
| 30.0 | Industrial | 14 | 931 | 937 | 942 | 949 | 956 | 962 | 968 | 976 |
| 60.0 | PSL | 15 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 |
| 70.0 | OPA | 16 | 89 | 89 | 90 | 91 | 93 | 94 | 95 | 96 |
| 80.0 | Company Use | 19 | 31 | 32 | 32 | 32 | 32 | 33 | 33 | 33 |
| 92.0 | Municipals | 17 | 179 | 179 | 180 | 181 | 182 | 183 | 184 | 185 |
| 97.0 | Cooperatives | 18 | . | . | . | . | . | . | . | . |
| 99.1 | Standby Gen | 20 | -25 | -25 | -25 | -25 | -25 | -25 | -25 | -25 |
| 99.2 | Interruptible Loads | 21 | -208 | -209 | -210 | -211 | -212 | -213 | -214 | -215 |
| | | ===== | ===== | ===== | ===== | ===== | ===== | ===== | ===== | ===== |
| | | 222 | 4,639 | 4,688 | 4,733 | 4,772 | 4,810 | 4,835 | 4,874 | 4,919 |

| class | desc | _2027 | _2028 | _2029 | _2030 | _2031 | _2032 | _2033 | class |
|---|---|---|---|---|---|---|---|---|---|
| 10.0 | Residential | 2,357 | 2,387 | 2,416 | 2,445 | 2,474 | 2,503 | 2,532 | 10.0 |
| 10.5 | Res SEER | -45 | -49 | -54 | -56 | -57 | -58 | -59 | 10.5 |
| 10.6 | Res Eff Lites | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10.6 |
| 10.7 | Res SCE&G EE | -43 | -49 | -56 | -63 | -70 | -77 | -84 | 10.7 |
| 10.8 | Res Water Heater Eff. | -2 | -2 | -2 | -2 | -2 | -2 | -2 | 10.8 |
| 10.9 | Res NEM Solar PV | -21 | -21 | -21 | -21 | -21 | -22 | -22 | 10.9 |
| 20.0 | Commercial | 1,713 | 1,733 | 1,753 | 1,772 | 1,792 | 1,811 | 1,830 | 20.0 |
| 20.5 | Com Standby Gen | -11 | -11 | -11 | -11 | -11 | -11 | -11 | 20.5 |
| 20.6 | Com Eff Lites | -39 | -45 | -51 | -57 | -63 | -69 | -76 | 20.6 |
| 20.7 | Com SCE&G EE | -9 | -10 | -11 | -12 | -14 | -15 | -16 | 20.7 |
| 30.0 | Industrial | 983 | 991 | 999 | 1,007 | 1,014 | 1,022 | 1,029 | 30.0 |
| 60.0 | PSL | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 60.0 |
| 70.0 | OPA | 97 | 98 | 99 | 101 | 102 | 103 | 104 | 70.0 |
| 80.0 | Company Use | 33 | 34 | 34 | 34 | 34 | 35 | 35 | 80.0 |
| 92.0 | Municipals | 186 | 187 | 188 | 189 | 190 | 192 | 193 | 92.0 |
| 97.0 | Cooperatives | . | . | . | . | . | . | . | 97.0 |
| 99.1 | Standby Gen | -25 | -25 | -25 | -25 | -25 | -25 | -25 | 99.1 |
| 99.2 | Interruptible Loads | -216 | -218 | -219 | -220 | -221 | -222 | -223 | 99.2 |
| | | ===== | ===== | ===== | ===== | ===== | ===== | ===== | ===== |
| | | 4,961 | 5,003 | 5,042 | 5,084 | 5,125 | 5,168 | 5,208 | 772.6 |



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The following Table 5 has a description of each component in the forecast.

**Table 5**

| Category | | Description |
|---|---|---|
| 10.0 | Residential | Residential Base Load |
| 10.5 | Res SEER | Adjustment for Improved SEER Rating |
| 10.6 | Res Eff Lites | Adjusment for More Efficient Lighting |
| 10.7 | Res SCE&G EE | Adjustment for Incremental Impact of SCE&G EE Programs |
| 10.8 | Res Water Heater Eff. | Adjustment for Improved Water Heater Efficiency |
| 10.9 | Res NEM Solar PV | Adjustment for Incremental NEM Customers |
| 20.0 | Commercial | Commercial Base Load |
| 20.5 | Com Standby Gen | Retail Standby Generation |
| 20.6 | Com Eff Lites | Adjusment for More Efficient Lighting |
| 20.7 | Com SCE&G EE | Adjustment for Incremental Impact of SCE&G EE Programs |
| 30.0 | Industrial | Industrial Base Load |
| 60.0 | PSL | Public Street Lighting |
| 70.0 | OPA | Other Public Authorities |
| 80.0 | Company Use | Company Use |
| 92.0 | Municipals | Municipalities |
| 97.0 | Cooperatives | Cooperatives |
| 99.1 | Standby Gen | Wholesale Standby Generation |
| 99.2 | Interruptible Loads | Retail Interruptible Load |



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The following Table 6 shows all the components that comprise the winter peak demand forecast.

**Table 6 - WINTER PEAK DEMAND FORECAST**

| class | desc | iord | _2019 | _2020 | _2021 | _2022 | _2023 | _2024 | _2025 | _2026 |
|---|---|---|---|---|---|---|---|---|---|---|
| 10.0 | Residential | 1 | 2,558 | 2,599 | 2,634 | 2,667 | 2,700 | 2,733 | 2,767 | 2,802 |
| 10.5 | Res SEER | 5 | -10 | -11 | -13 | -15 | -33 | -37 | -41 | -45 |
| 10.6 | Res Eff Lites | 6 | -20 | -30 | -40 | -42 | -44 | -47 | -49 | -52 |
| 10.7 | Res SCE&G EE | 7 | 0 | -6 | -12 | -18 | -24 | -30 | -36 | -42 |
| 10.8 | Res Water Heater Eff. | 8 | -2 | -3 | -4 | -4 | -5 | -5 | -6 | -6 |
| 10.9 | Res NEM Solar PV | 9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20.0 | Commercial | 10 | 1,359 | 1,379 | 1,396 | 1,412 | 1,429 | 1,446 | 1,463 | 1,479 |
| 20.5 | Com Standby Gen | 11 | -11 | -11 | -11 | -11 | -11 | -11 | -11 | -11 |
| 20.6 | Com Eff Lites | 12 | -3 | -10 | -19 | -26 | -32 | -36 | -38 | -39 |
| 20.7 | Com SCE&G EE | 13 | 0 | -1 | -2 | -4 | -5 | -6 | -7 | -8 |
| 30.0 | Industrial | 14 | 797 | 804 | 810 | 816 | 820 | 826 | 832 | 838 |
| 60.0 | PSL | 15 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 70.0 | OPA | 16 | 73 | 74 | 75 | 76 | 77 | 78 | 79 | 80 |
| 80.0 | Company Use | 19 | 32 | 32 | 32 | 33 | 33 | 33 | 33 | 34 |
| 92.0 | Municipals | 17 | 177 | 178 | 179 | 180 | 181 | 182 | 183 | 184 |
| 97.0 | Cooperatives | 18 | . | . | . | . | . | . | . | . |
| 99.1 | Standby Gen | 20 | -25 | -25 | -25 | -25 | -25 | -25 | -25 | -25 |
| 99.2 | Interruptible Loads | 21 | -179 | -180 | -181 | -182 | -182 | -183 | -184 | -185 |
| | | ===== | ===== | ===== | ===== | ===== | ===== | ===== | ===== | ===== |
| | | 222 | 4,749 | 4,792 | 4,822 | 4,860 | 4,882 | 4,921 | 4,963 | 5,007 |

| class | desc | _2027 | _2028 | _2029 | _2030 | _2031 | _2032 | _2033 | class |
|---|---|---|---|---|---|---|---|---|---|
| 10.0 | Residential | 2,837 | 2,873 | 2,906 | 2,941 | 2,976 | 3,010 | 3,045 | 10.0 |
| 10.5 | Res SEER | -49 | -53 | -55 | -56 | -57 | -58 | -60 | 10.5 |
| 10.6 | Res Eff Lites | -54 | -57 | -60 | -62 | -65 | -68 | -71 | 10.6 |
| 10.7 | Res SCE&G EE | -49 | -56 | -62 | -69 | -76 | -83 | -90 | 10.7 |
| 10.8 | Res Water Heater Eff. | -7 | -8 | -8 | -8 | -8 | -8 | -8 | 10.8 |
| 10.9 | Res NEM Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10.9 |
| 20.0 | Commercial | 1,497 | 1,514 | 1,530 | 1,547 | 1,564 | 1,581 | 1,598 | 20.0 |
| 20.5 | Com Standby Gen | -11 | -11 | -11 | -11 | -11 | -11 | -11 | 20.5 |
| 20.6 | Com Eff Lites | -45 | -51 | -57 | -63 | -69 | -75 | -81 | 20.6 |
| 20.7 | Com SCE&G EE | -10 | -11 | -12 | -14 | -15 | -16 | -17 | 20.7 |
| 30.0 | Industrial | 845 | 852 | 859 | 865 | 872 | 878 | 885 | 30.0 |
| 60.0 | PSL | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 60.0 |
| 70.0 | OPA | 81 | 82 | 83 | 84 | 85 | 85 | 86 | 70.0 |
| 80.0 | Company Use | 34 | 34 | 34 | 35 | 35 | 35 | 36 | 80.0 |
| 92.0 | Municipals | 185 | 186 | 187 | 188 | 189 | 191 | 192 | 92.0 |
| 97.0 | Cooperatives | . | . | . | . | . | . | . | 97.0 |
| 99.1 | Standby Gen | -25 | -25 | -25 | -25 | -25 | -25 | -25 | 99.1 |
| 99.2 | Interruptible Loads | -186 | -187 | -188 | -189 | -190 | -191 | -192 | 99.2 |
| | | ===== | ===== | ===== | ===== | ===== | ===== | ===== | ===== |
| | | 5,046 | 5,085 | 5,124 | 5,166 | 5,208 | 5,248 | 5,290 | 772.6 |

**Customer and Sales Growth Comparisons: History and Forecast**

The following table shows the growth in customers and sales over the last five years and that projected over the next five years. The variable or header labeled "hisgr" is the compound average annual growth rate for the years 2013 through 2018 and the variable "forgr" is the growth rate for the period 2018 through 2023. For the residential class, the number of customers is the driver for growth in residential peak demand. The table shows that the projected growth over the next five years is only slightly lower than over the previous five years, i.e., 1.5% versus 1.4%. Similarly, for the commercial class of customers, the projected growth rate is only slightly lower than the historical rate, 1.2% versus 1.1%. While not affecting the peak demand forecast, the weather normalized average kWh per customer for both residential and commercial customers is expected to continue declining over the next five years but at a slower rate than in the last five years. Industrial GWH sales are expected to decrease over the next five years but this is mostly an accounting phenomenon which is explained after tables 7 and 8.



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**Table 7 – Customers and Weather Normalized Sales Over +/- 5 Years**

| CLASS=Residential | | | | | | |
|---|---|---|---|---|---|---|
| desc | CLASS | _2013 | _2018 | _2023 | hisgr | forgr |
| Nbr Customers | Residential | 580,407 | 624,849 | 671,268 | 1.5 | 1.4 |
| kWh per Customer | Residential | 13,407 | 12,701 | 12,177 | -1.1 | -0.8 |
| Total GWH Sales | Residential | 7,782 | 7,936 | 8,174 | 0.4 | 0.6 |
| **CLASS=Commercial** | | | | | | |
| desc | CLASS | _2013 | _2018 | _2023 | hisgr | forgr |
| Nbr Customers | Commercial | 90,770 | 96,378 | 101,944 | 1.2 | 1.1 |
| kWh per Customer | Commercial | 80,287 | 74,435 | 73,385 | -1.5 | -0.3 |
| Total GWH Sales | Commercial | 7,288 | 7,174 | 7,481 | -0.3 | 0.8 |
| **CLASS=Industrial** | | | | | | |
| desc | CLASS | _2013 | _2018 | _2023 | hisgr | forgr |
| Total GWH Sales | Industrial | 6,005 | 6,321 | 6,143 | 1.0 | -0.6 |
| **CLASS=All_Sales** | | | | | | |
| desc | CLASS | _2013 | _2018 | _2023 | hisgr | forgr |
| Total GWH Sales | All_Sales | 22,625 | 22,916 | 23,331 | 0.3 | 0.4 |

The following Table 8 contains similar information on a 15-year basis. And similar comments could be made.

**Table 8 – Customers and Weather Normalized Sales Over +/- 15 Years**

| CLASS=Residential | | | | | | |
|---|---|---|---|---|---|---|
| desc | CLASS | _2003 | _2018 | _2033 | hisgr | forgr |
| Nbr Customers | Residential | 481,380 | 624,849 | 757,596 | 1.8 | 1.3 |
| kWh per Customer | Residential | 14,876 | 12,701 | 12,251 | -1.0 | -0.2 |
| Total GWH Sales | Residential | 7,161 | 7,936 | 9,282 | 0.7 | 1.0 |
| **CLASS=Commercial** | | | | | | |
| desc | CLASS | _2003 | _2018 | _2033 | hisgr | forgr |
| Nbr Customers | Commercial | 78,999 | 96,378 | 114,094 | 1.3 | 1.1 |
| kWh per Customer | Commercial | 84,798 | 74,435 | 69,800 | -0.9 | -0.4 |
| Total GWH Sales | Commercial | 6,699 | 7,174 | 7,964 | 0.5 | 0.7 |
| **CLASS=Industrial** | | | | | | |
| desc | CLASS | _2003 | _2018 | _2033 | hisgr | forgr |
| Total GWH Sales | Industrial | 6,543 | 6,321 | 6,658 | -0.2 | 0.3 |
| **CLASS=All_Sales** | | | | | | |
| desc | CLASS | _2003 | _2018 | _2033 | hisgr | forgr |
| Total GWH Sales | All_Sales | 22,347 | 22,916 | 25,563 | 0.2 | 0.7 |

Regarding the projected growth, or lack thereof, in industrial sales, the generator in a large cogeneration facility has been acquired by the host manufacturing customer. Therefore, instead of the generator output being SCE&G's generation and all energy consumption by the host being recorded as SCE&G's industrial sales, the generator output will be consumed at the customer's site and only the residual energy needs of the host customer will be industrial sales from SCE&G. To get a better estimate of industrial growth on SCE&G's system, 500 GWHs can be added to the industrial sales level in the forecasted years. For example, the adjusted industrial growth rate for the years 2018 through 2023 is 1.0% instead of -0.6% what is shown in the table and for the period 2018-2033, the adjusted growth is 0.8% instead of -0.2% as shown in the table.



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# APPENDIX

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**Figure A1: Containing Components of Demand Forecast in Future "Calendar" Years**

| | | | Energy Forecast | | Summer Peak | | | Winter Peak | |
|---|---|---|---|---|---|---|---|---|---|
| yr | class | desc | Customer | GWH Sales | kW Per | Factor | Peak Demand | kW Per | Peak Demand |
| 2020 | 10.0 | Res | 643,719 | . | 3.310 | 1.0098 | 2,152 | 3.973 | 2,558 |
| | 10.2 | Res.Adj | . | . | . | . | -29 | . | -32 |
| | 20.0 | Com | 98,116 | . | 15.887 | 1.0098 | 1,574 | 13.856 | 1,359 |
| | 20.2 | Com.Adj | . | . | . | . | -3 | . | -3 |
| | 30.0 | Ind | . | 5986.2 | 1.047 | 1.0098 | 723 | 0.904 | 618 |
| | 30.1 | Ind.DR | . | . | . | . | 211 | . | 179 |
| | 30.2 | Ind.Adj | . | . | . | . | 3 | . | 0 |
| | 60.0 | PSL | . | 157.0 | 0.129 | 1.0098 | 2 | 0.157 | 3 |
| | 70.0 | OPA | . | 519.5 | 1.485 | 1.0098 | 89 | 1.232 | 73 |
| | 92.0 | Muni | . | 901.2 | 1.725 | 1.0098 | 179 | 1.722 | 177 |
| | 98.1 | CoUse | . | . | . | . | 32 | . | 32 |
| | 98.5 | DR | . | . | . | . | -245 | . | -215 |
| 2020 | | | . | . | . | . | 4,688 | . | 4,749 |
| 2025 | 10.0 | Res | 687,796 | . | 3.310 | 1.0098 | 2,299 | 3.973 | 2,733 |
| | 10.2 | Res.Adj | . | . | . | . | -89 | . | -119 |
| | 20.0 | Com | 104,361 | . | 15.887 | 1.0098 | 1,674 | 13.856 | 1,446 |
| | 20.2 | Com.Adj | . | . | . | . | -42 | . | -42 |
| | 30.0 | Ind | . | 6230.8 | 1.047 | 1.0098 | 752 | 0.904 | 643 |
| | 30.1 | Ind.DR | . | . | . | . | 216 | . | 183 |
| | 60.0 | PSL | . | 167.3 | 0.129 | 1.0098 | 2 | 0.157 | 3 |
| | 70.0 | OPA | . | 554.3 | 1.485 | 1.0098 | 95 | 1.232 | 78 |
| | 92.0 | Muni | . | 924.5 | 1.725 | 1.0098 | 184 | 1.722 | 182 |
| | 98.1 | CoUse | . | . | . | . | 33 | . | 33 |
| | 98.5 | DR | . | . | . | . | -250 | . | -219 |
| 2025 | | | . | . | . | . | 4,874 | . | 4,921 |
| 2030 | 10.0 | Res | 731,487 | . | 3.310 | 1.0098 | 2,445 | 3.973 | 2,906 |
| | 10.2 | Res.Adj | . | . | . | . | -142 | . | -185 |
| | 20.0 | Com | 110,442 | . | 15.887 | 1.0098 | 1,772 | 13.856 | 1,530 |
| | 20.2 | Com.Adj | . | . | . | . | -69 | . | -69 |
| | 30.0 | Ind | . | 6499.4 | 1.047 | 1.0098 | 785 | 0.904 | 671 |
| | 30.1 | Ind.DR | . | . | . | . | 222 | . | 188 |
| | 60.0 | PSL | . | 177.8 | 0.129 | 1.0098 | 3 | 0.157 | 3 |
| | 70.0 | OPA | . | 587.4 | 1.485 | 1.0098 | 101 | 1.232 | 83 |
| | 92.0 | Muni | . | 951.9 | 1.725 | 1.0098 | 189 | 1.722 | 187 |
| | 98.1 | CoUse | . | . | . | . | 34 | . | 34 |
| | 98.5 | DR | . | . | . | . | -256 | . | -224 |
| 2030 | | | . | . | . | . | 5,084 | . | 5,124 |



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# Concerning Figures A2-A13

Figures A2-A13 show the results of an "Analysis of Variance" approach to the changes in kW per customer or kW per kWh for each of the classes of customer, i.e. an ANOVA model. When weather is a statistically significant factor in the variation of peak contribution, an "Analysis of Covariance" is used, i.e. an ANCOVA model. Figures A2-A7 show results for the winter and Figures A8-A13, for the summer. The customer classes are: residential, commercial, industrial, pubic street lighting, other public authorities and municipalities.

The fixed effects variables are 0-1 dummy variables where the start and stop year, i.e. the years when the variable equals one, are indicated in the name of the variable. For example, in Figure A2 showing results for the residential class in winter, the variable "i03_11", takes on the value 1 in the years 2003 through 2011 and 0 elsewhere.

The weather variables for the peak day used in the models are:

Mntmp=minimum daily temperature;
Hdh60 = heating degree hours base 60;
Cdh = cooling degree hours base 75; and
Maxtmp=maximum daily temperature.

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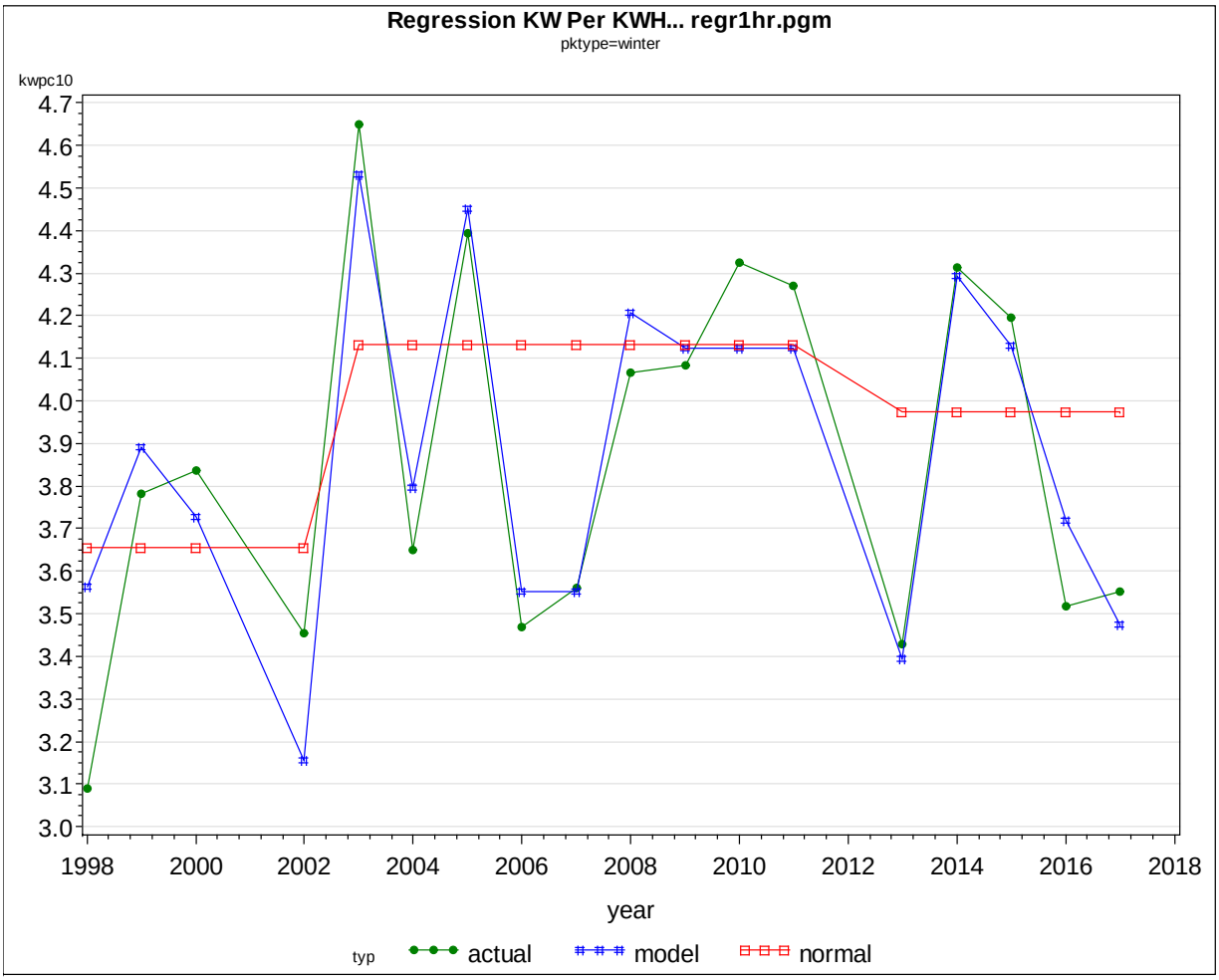
**Figure A2: Residential Winter kW per Customer Regression Equation**

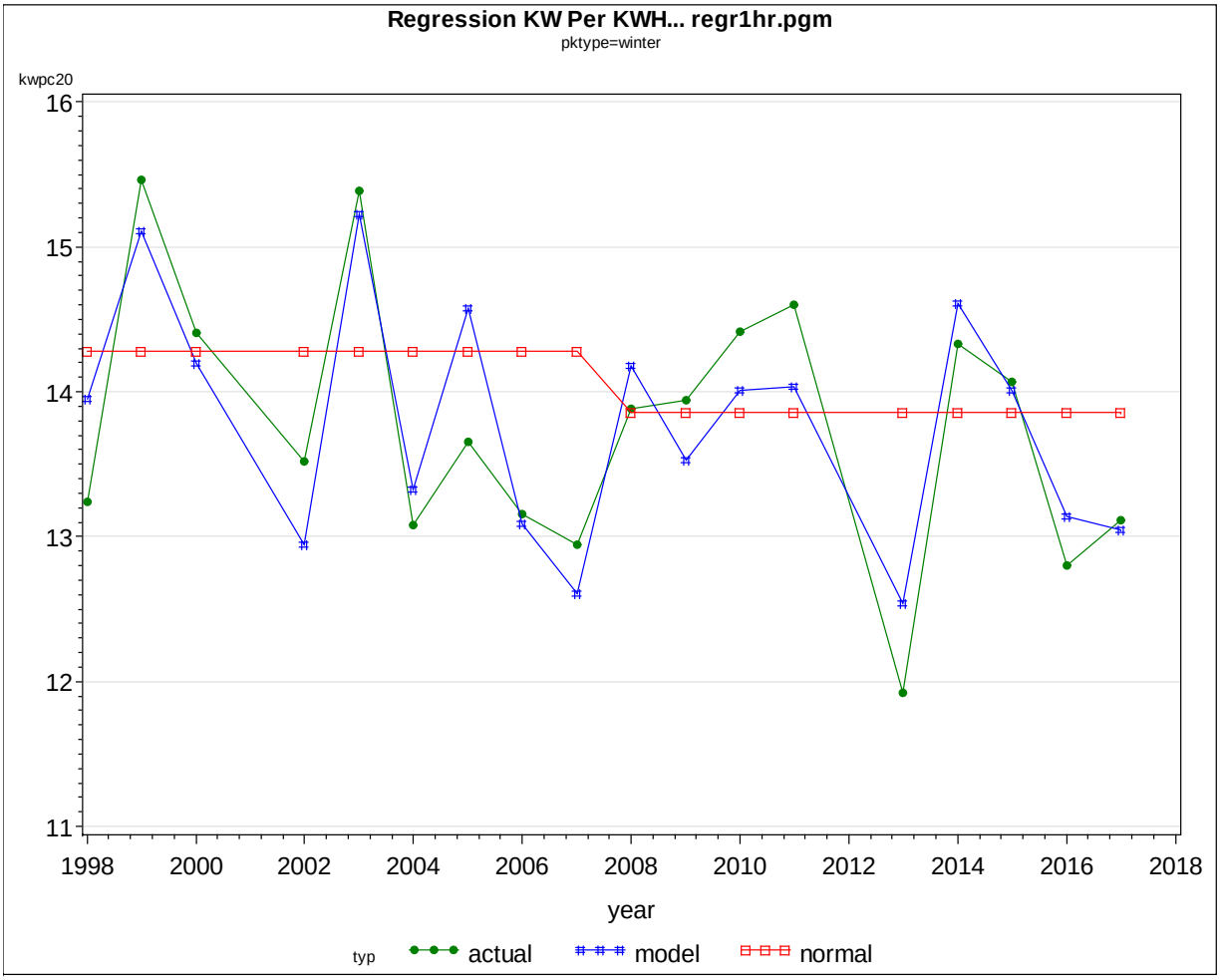



| | | | |
|---|---|---|---|
| Root MSE | 0.16765 | R-Square | 0.8600 |
| Dependent Mean | 3.89496 | Adj R-Sq | 0.8300 |
| Coeff Var | 4.30439 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 5.60029 | 0.23202 | 24.14 | <.0001 | 0 |
| i98_02 | 1 | -0.31863 | 0.11965 | -2.66 | 0.0185 | 1.36938 |
| i03_11 | 1 | 0.15893 | 0.09417 | 1.69 | 0.1136 | 1.36462 |
| mntmp | 1 | -0.08176 | 0.00998 | -8.19 | <.0001 | 1.02115 |

**Figure A3: Commercial Winter kW per Customer Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.46576 | R-Square | 0.7694 |
| Dependent Mean | 13.77535 | Adj R-Sq | 0.7386 |
| Coeff Var | 3.38112 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 6.58985 | 1.02200 | 6.45 | <.0001 | 0 |
| i98_07 | 1 | 0.42590 | 0.22305 | 1.91 | 0.0755 | 1.02117 |
| hdh60 | 1 | 0.02400 | 0.00342 | 7.02 | <.0001 | 1.02117 |



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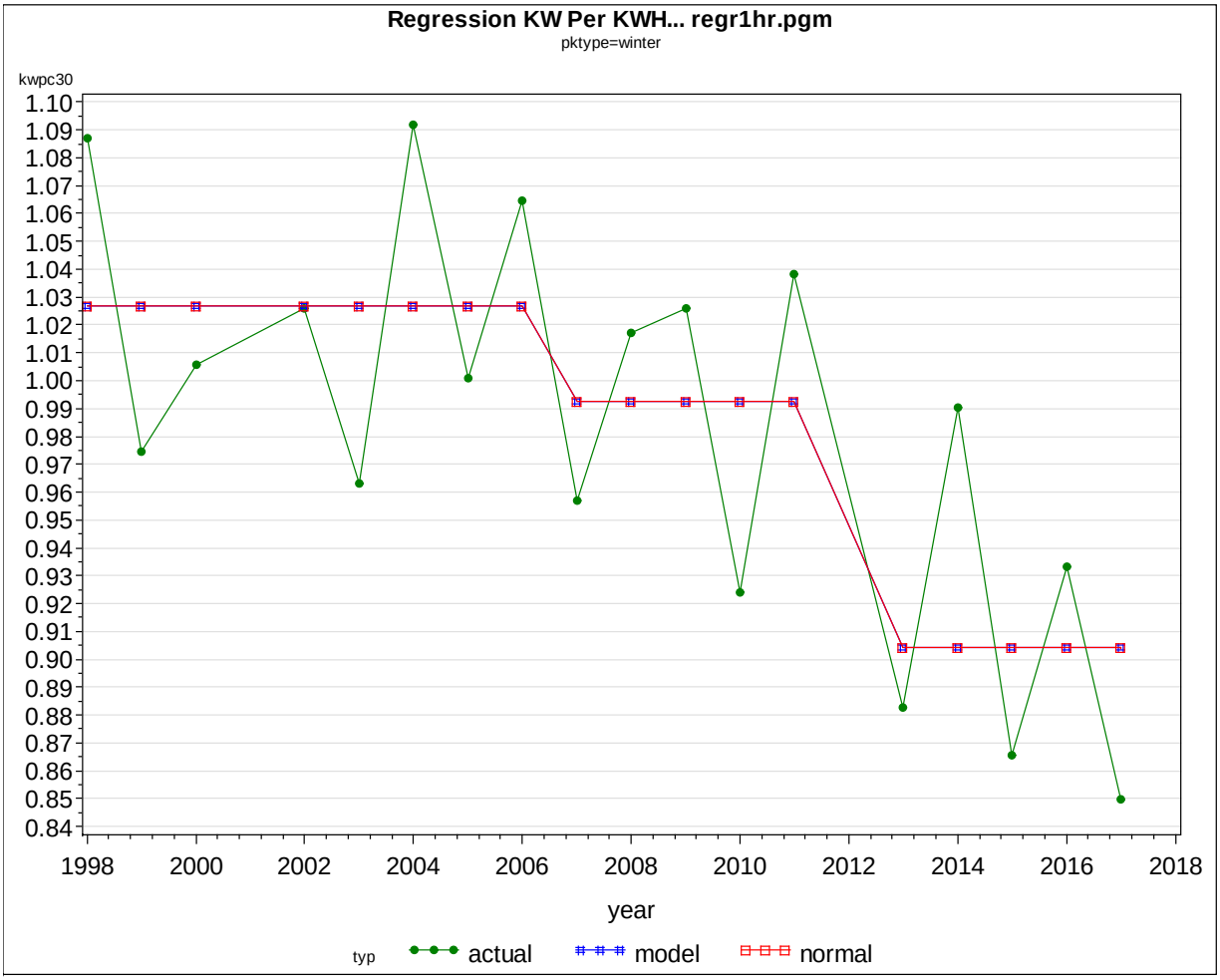
**Figure A4: Industrial Winter kW per kWh Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.05172 | R-Square | 0.5383 |
| Dependent Mean | 0.98318 | Adj R-Sq | 0.4767 |
| Coeff Var | 5.26080 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 0.90408 | 0.02316 | 39.03 | <.0001 | 0 |
| i98_06 | 1 | 0.12263 | 0.02951 | 4.16 | 0.0008 | 1.44605 |
| i07_11 | 1 | 0.08833 | 0.03274 | 2.70 | 0.0165 | 1.44605 |



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**Figure A5: Public Street Lighting Winter kW per kWh Regression Equation**

| | | | |
|---|---|---|---|
| Root MSE | 0.03107 | R-Square | 0.7780 |
| Dependent Mean | 0.19808 | Adj R-Sq | 0.7641 |
| Coeff Var | 15.68591 | | |

**Parameter Estimates**

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 0.15665 | 0.00937 | 16.72 | <.0001 | 0 |
| i98_05 | 1 | 0.11875 | 0.01586 | 7.49 | <.0001 | 1.00000 |



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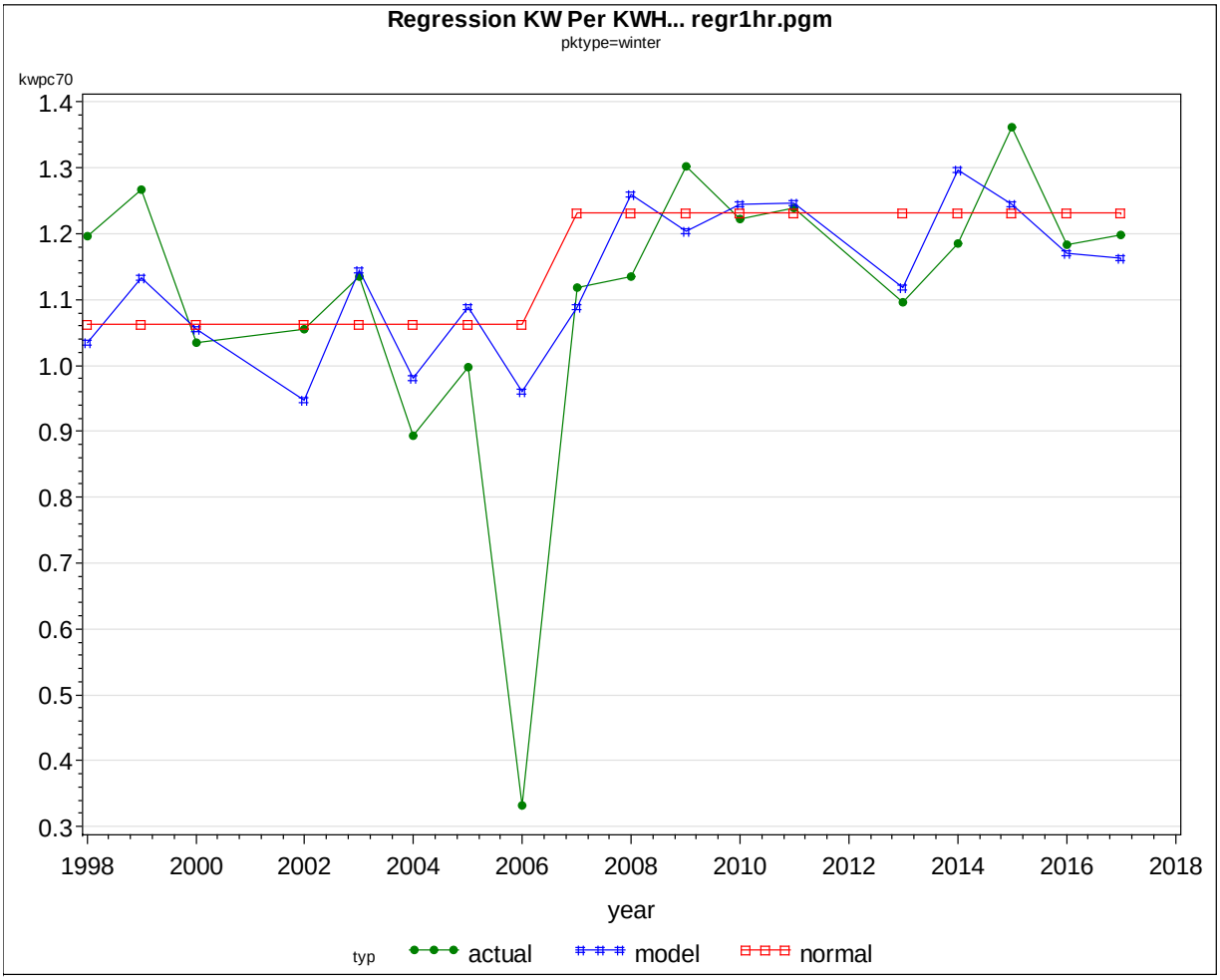
**Figure A6: Other Public Authorities Winter kW per kWh Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.12947 | R-Square | 0.4117 |
| Dependent Mean | 1.13890 | Adj R-Sq | 0.3333 |
| Coeff Var | 11.36830 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 0.60597 | 0.28380 | 2.14 | 0.0496 | 0 |
| i98_06 | 1 | -0.17013 | 0.06345 | -2.68 | 0.0171 | 1.01477 |
| hdh60 | 1 | 0.00207 | 0.00097174 | 2.13 | 0.0502 | 1.01477 |



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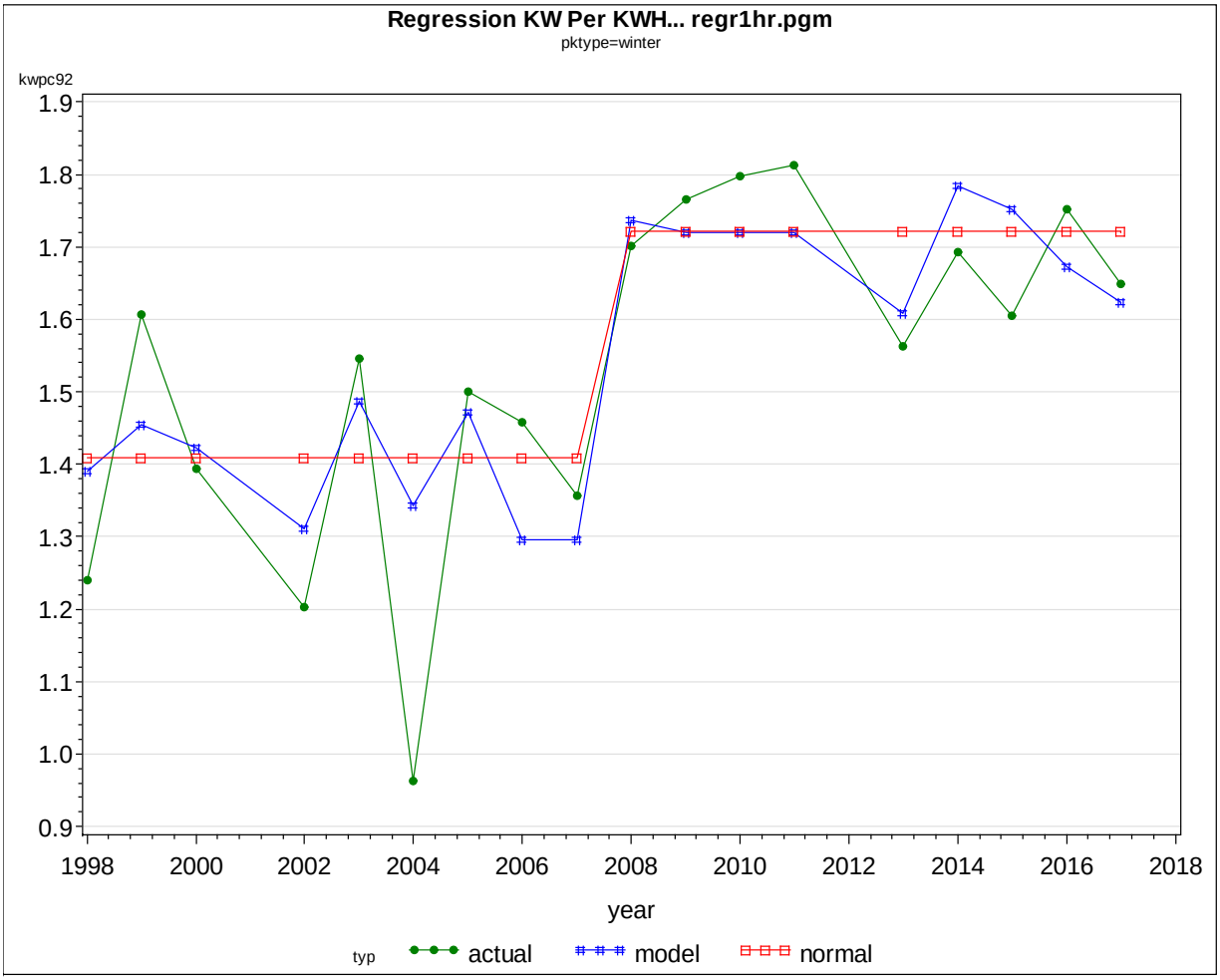
**Figure A7: Municipal Winter kW per kWh Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.11997 | R-Square | 0.7024 |
| Dependent Mean | 1.55133 | Adj R-Sq | 0.6627 |
| Coeff Var | 7.73352 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 2.04098 | 0.15377 | 13.27 | <.0001 | 0 |
| i98_07 | 1 | -0.31344 | 0.05747 | -5.45 | <.0001 | 1.00040 |
| mntmp | 1 | -0.01603 | 0.00707 | -2.27 | 0.0386 | 1.00040 |



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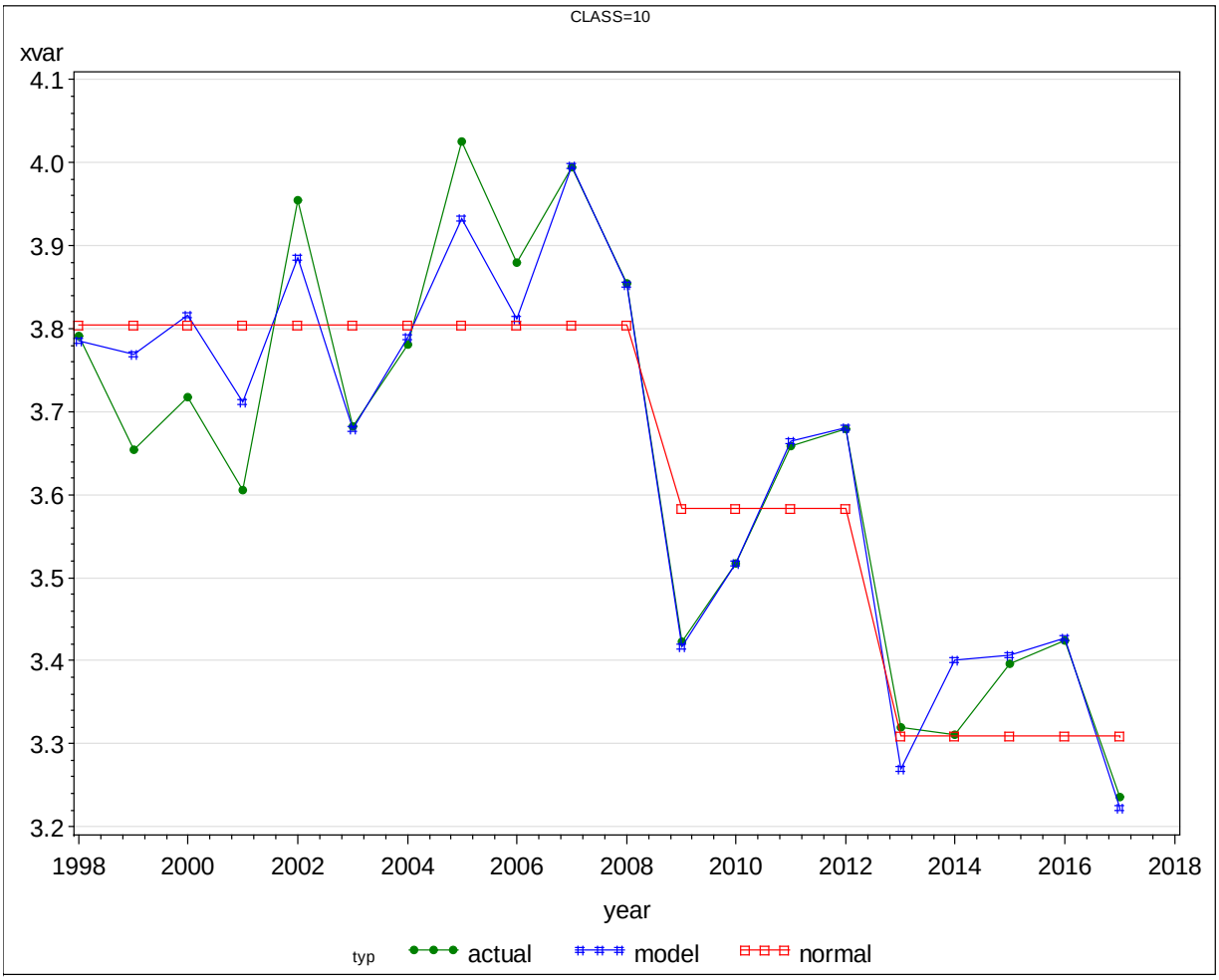
**Figure A8: Residential Summer kW per Customer Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.03102 | R-Square | 0.9781 |
| Dependent Mean | 3.62672 | Adj R-Sq | 0.9740 |
| Coeff Var | 0.85544 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 2.37371 | 0.08296 | 28.61 | <.0001 | 0 |
| i98_08 | 1 | 0.49447 | 0.02032 | 24.33 | <.0001 | 1.50540 |
| i09_12 | 1 | 0.27372 | 0.02280 | 12.01 | <.0001 | 1.54897 |
| cdh | 1 | 0.00527 | 0.00044121 | 11.94 | <.0001 | 1.03613 |



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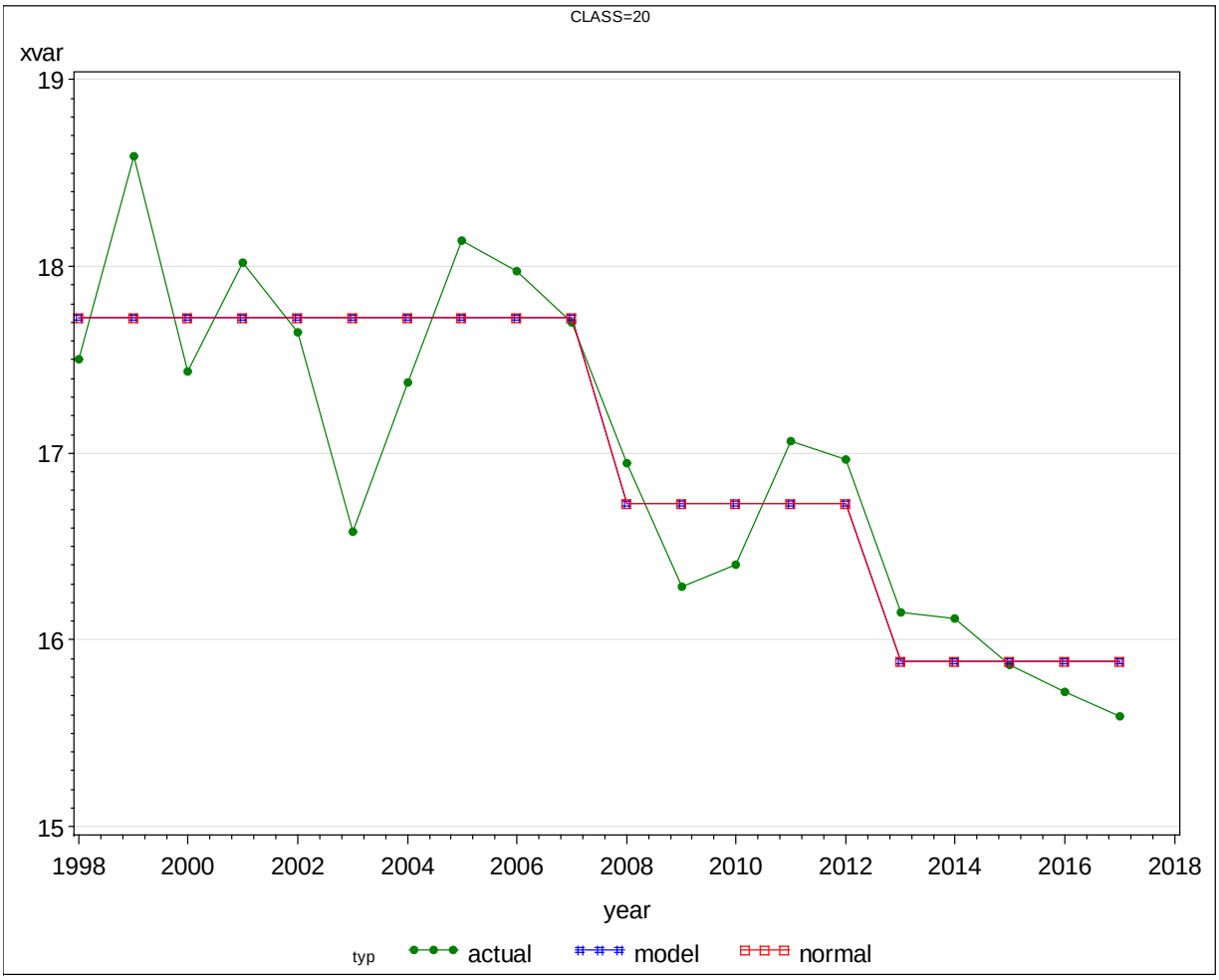
**Figure A9: Commercial Summer kW per Customer Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.38840 | R-Square | 0.8163 |
| Dependent Mean | 16.98935 | Adj R-Sq | 0.7946 |
| Coeff Var | 2.28611 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 15.88726 | 0.17370 | 91.47 | <.0001 | 0 |
| i98_07 | 1 | 1.83709 | 0.21563 | 8.52 | <.0001 | 1.48023 |
| i08_12 | 1 | 0.84600 | 0.24564 | 3.44 | 0.0031 | 1.48023 |



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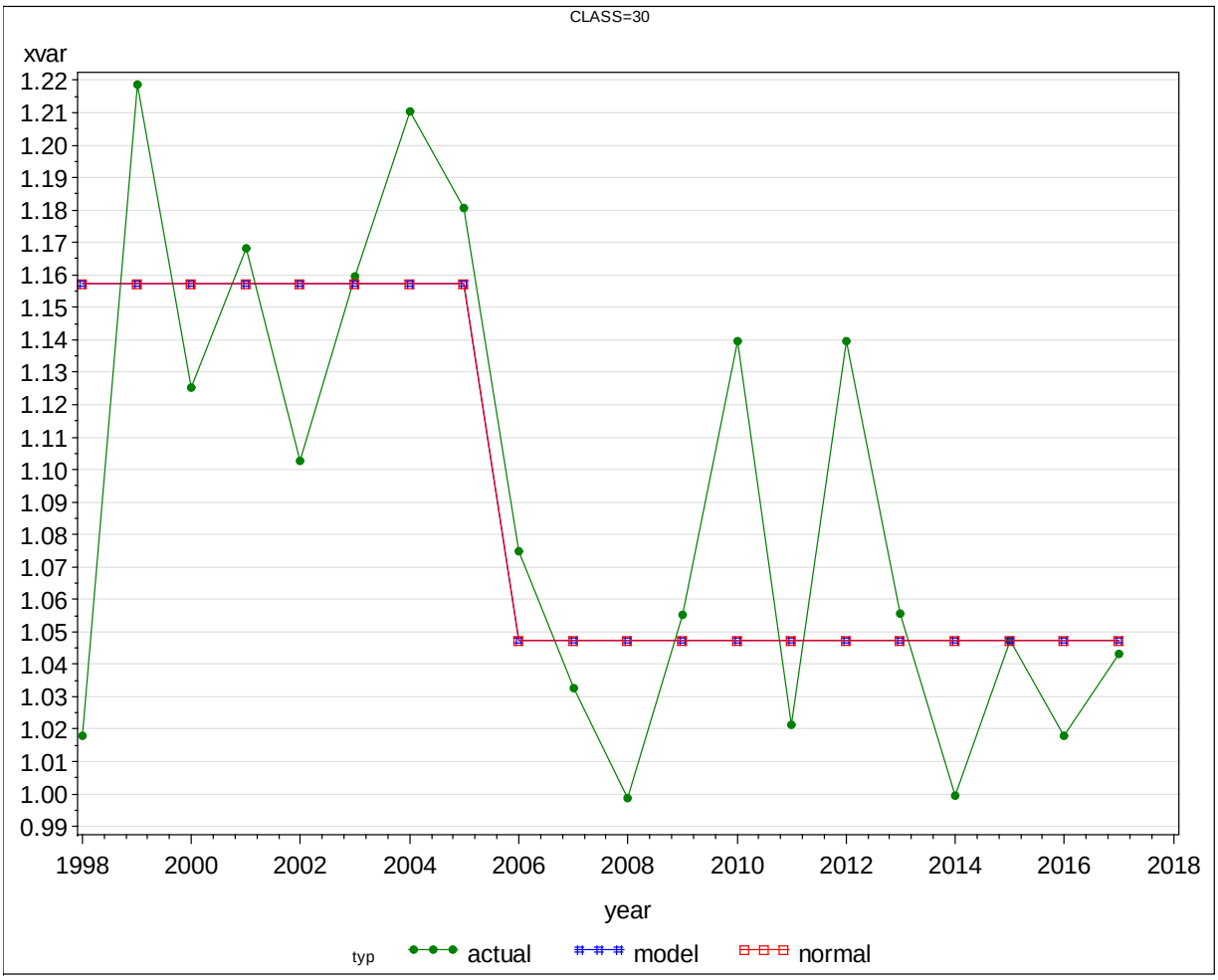
**Figure A10: Industrial Summer kW per kWh Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.04655 | R-Square | 0.5834 |
| Dependent Mean | 1.09088 | Adj R-Sq | 0.5603 |
| Coeff Var | 4.26685 | | |

**Parameter Estimates**

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 1.04726 | 0.01381 | 75.86 | <.0001 | 0 |
| i98_05 | 1 | 0.11015 | 0.02194 | 5.02 | <.0001 | 1.00000 |



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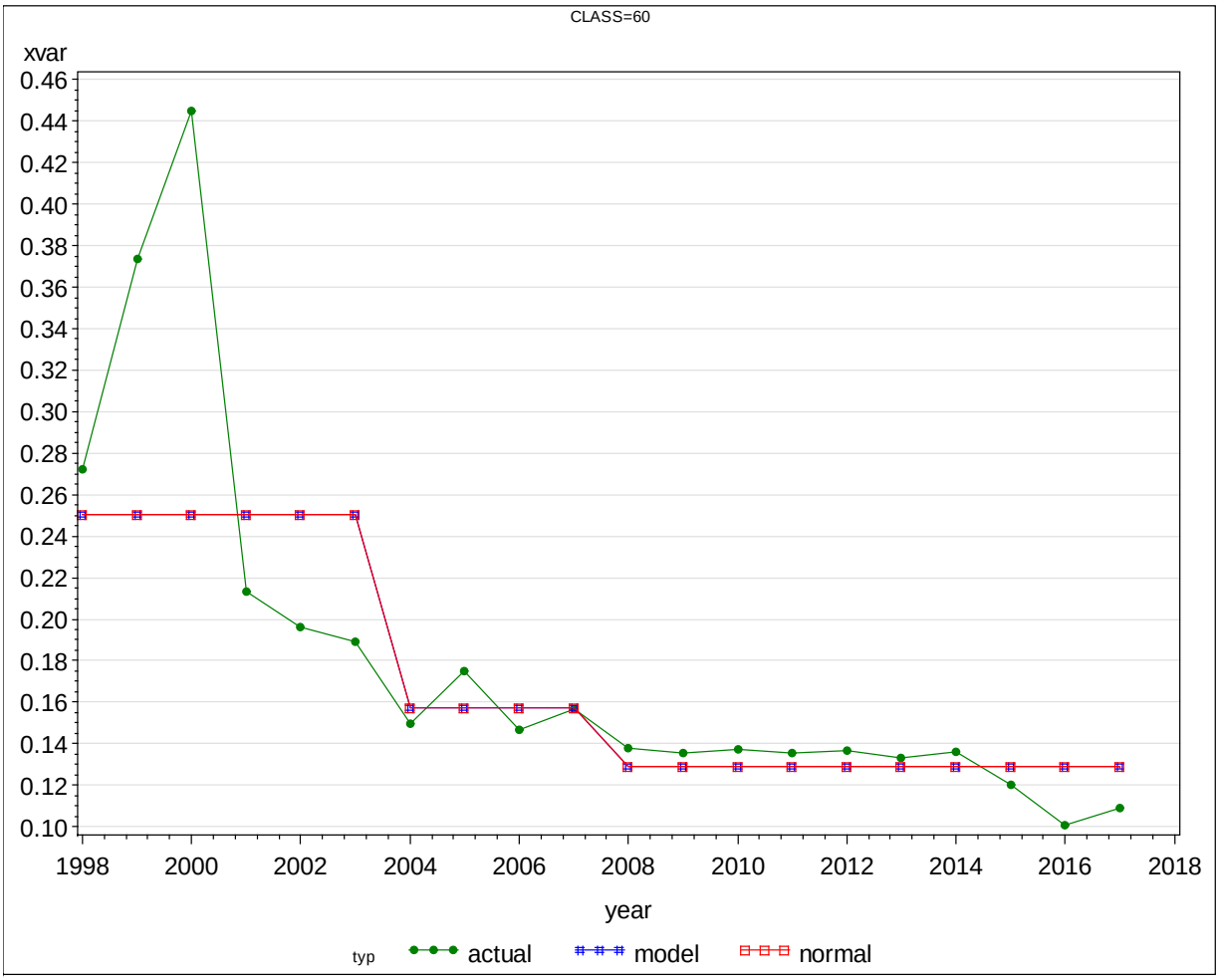
**Figure A11: Public Street Lighting Summer kW per kWh Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.02724 | R-Square | 0.7087 |
| Dependent Mean | 0.15512 | Adj R-Sq | 0.6744 |
| Coeff Var | 17.56336 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 0.12876 | 0.00871 | 14.78 | <.0001 | 0 |
| i98_03 | 1 | 0.12191 | 0.01896 | 6.43 | <.0001 | 1.06530 |
| i04_07 | 1 | 0.02826 | 0.01617 | 1.75 | 0.0986 | 1.06530 |



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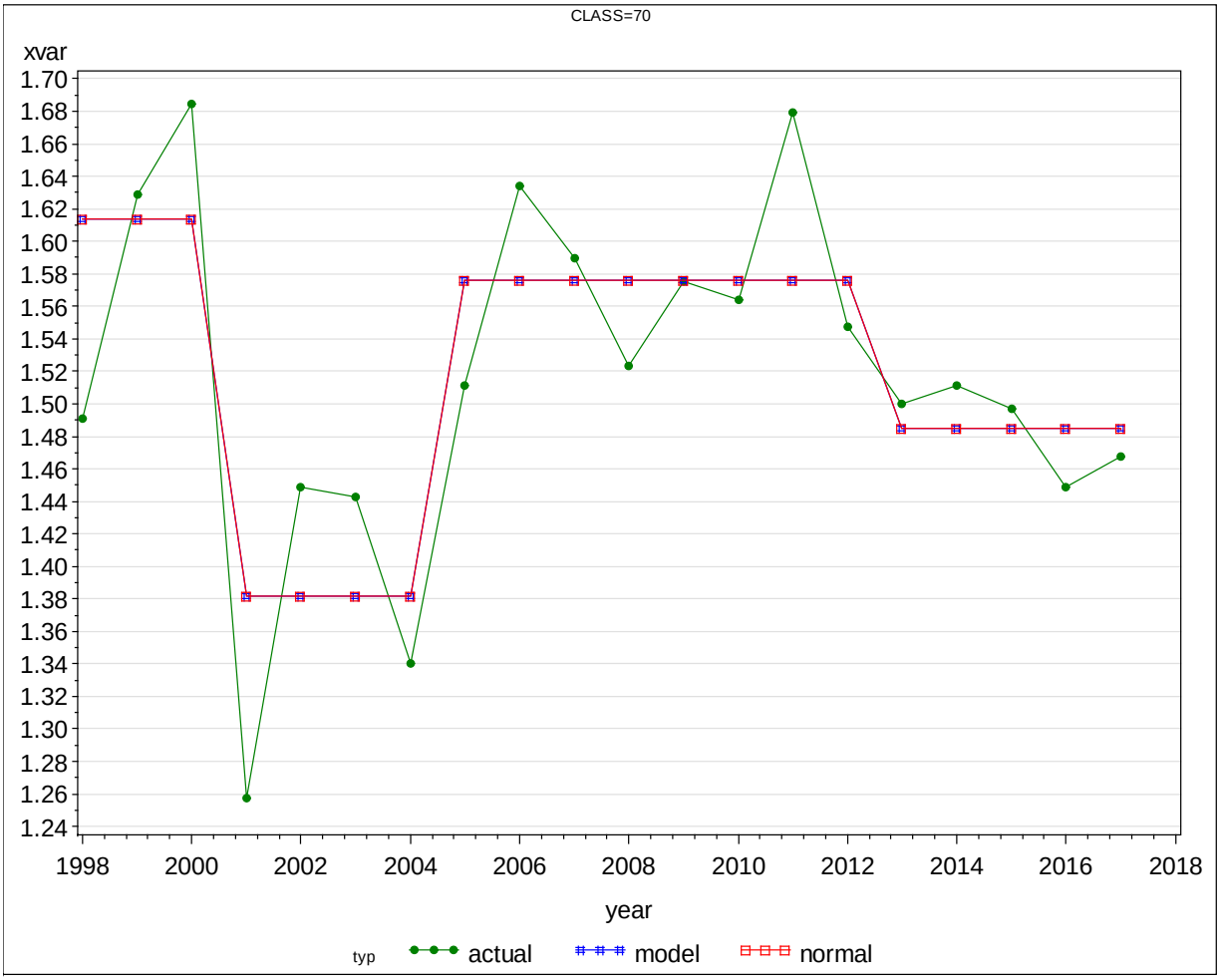
**Figure A12: Other Public Authorities Summer kW per kWh Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.06103 | R-Square | 0.6764 |
| Dependent Mean | 1.52037 | Adj R-Sq | 0.6158 |
| Coeff Var | 4.01428 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 1.48502 | 0.02729 | 54.41 | <.0001 | 0 |
| i98_00 | 1 | 0.12849 | 0.04607 | 2.79 | 0.0131 | 1.32424 |
| i01_04 | 1 | -0.10295 | 0.04187 | -2.46 | 0.0257 | 1.40488 |
| i05_12 | 1 | 0.09095 | 0.03493 | 2.60 | 0.0192 | 1.52137 |



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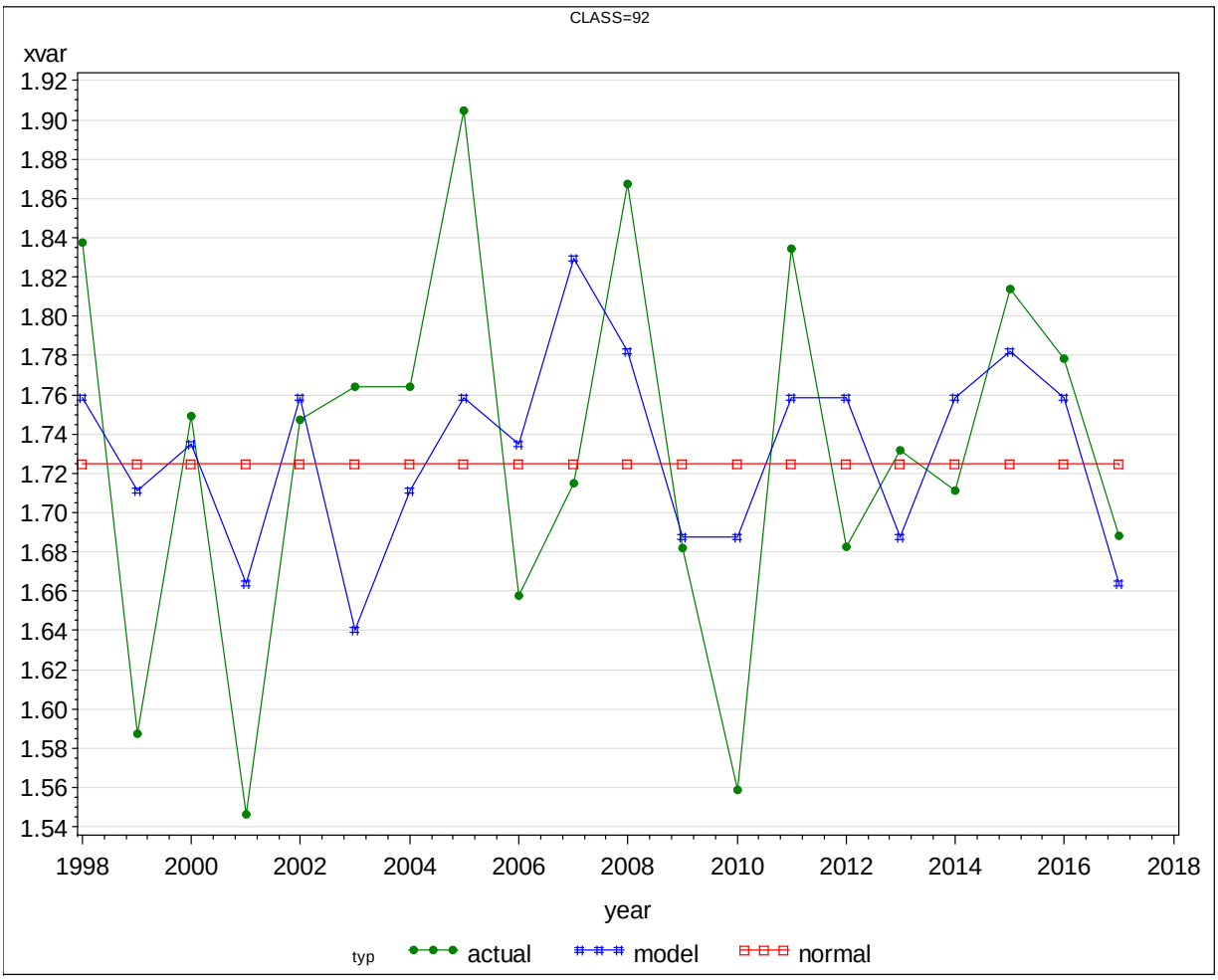
**Figure A13: Municipal Summer kW per kWh Regression Equation**




| | | | |
|---|---|---|---|
| Root MSE | 0.08684 | R-Square | 0.2443 |
| Dependent Mean | 1.73104 | Adj R-Sq | 0.2023 |
| Coeff Var | 5.01673 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | -0.58169 | 0.95897 | -0.61 | 0.5517 | 0 |
| maxtmp | 1 | 0.02364 | 0.00980 | 2.41 | 0.0267 | 1.00000 |

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**Exhibit No. __ (JML-3)**

# 2018 Reserve Margin Study

SCE&G is becoming Dominion Energy®

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## Summary

SCE&G's reserve margin policy is summarized in the following table.

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

The analysis contained in this study suggested a summer peaking reserve margin of 14.3% and a winter peaking reserve margin of 20.2%. SCE&G believes these results support the existing reserve margin policy. Also, the analysis for the base level of reserves to support operation of the system throughout the year outside of seasonal peaking periods suggested a reserve level of 13.4% in summer and 14.9% in winter. These results support the existing policy and for the present SCE&G will maintain the base levels of reserve margin at 12% and 14% in summer and winter respectively.

## 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 MW 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, a regression study was performed for each season separately. Three years of data were combined using the months of June, July and August for the summer model and December 16 through March 16 for the winter model. The regression study followed the following steps for each season:

1. Define a set of explanatory variables such as cooling degree hours ("CDH") for summer and heating degree hours for winter ("HDH"). The square of these weather variables was added to the possible choices in case a quadratic equation provided the best fit. To avoid collinearity problems between the linear and squared terms, the deviation from the mean value of both CDH and HDH was used instead of the actual degree hours.
2. The stepwise model selection procedure in SAS was used to find the best set of explanatory variables to use in the regression equation to explain variations in daily peak demand. The stepwise procedure will add or subtract a variable to build the best regression model in terms of goodness of fit. A variable is added to the equation if it meets a specified significance level when added. After adding a variable, the stepwise procedure checks all the variables presently in the regression equation to make sure they meet a certain significance level to stay in the equation. A statistical significance level of 15% was used for both adding a variable and removing a variable. The SAS code that implements this procedure is shown in the appendix with the list of explanatory variables provided.
3. The best model specification chosen by the stepwise procedure was estimated first using a robust regression procedure to identify outliers in the data which are assigned appropriate weights by the modeling procedure. The final estimation of the model was made in a weighted regression analysis using those weights. This mitigated any bias from the squared residuals associated with outliers.



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4. The above was first performed for all the days in the summer season for which CDH was greater than zero and in the winter season for which HDH was greater than zero. To estimate a sensitivity to the data the entire process was repeated using the 100 hottest days in summer based on CDH and the coldest 100 days in winter based on HDH.
5. The stepwise procedure chose a quadratic formulation as the best fitting model in all four instances, i.e. in summer and winter and with all the days and with only the 100 extremist days. To estimate the sensitivity to the quadratic formulation, a linear model was designed by dropping the quadratic term out of the quadratic model in the 100-day scenario. Thus, there were three summer models and three winter models estimated.
6. The seasonal peak demand days on the system since 1991 were identified and the weather from those days as well as day of week and month of occurrence were entered into the six regression equations to estimate what the seasonal peak demand would be today if the historical peak conditions were present. For each season about 28 different peak demands were calculated. The average of these seasonal peaks was taken as an approximation of the peak demand under normal weather conditions and the difference between the maximum and the normal would represent the seasonal demand side risk which is the goal of this exercise.

The following chart compares the summer regression model's daily peak estimates to the actual daily peak demands. The estimated regression equations and related statistics are included as appendices.



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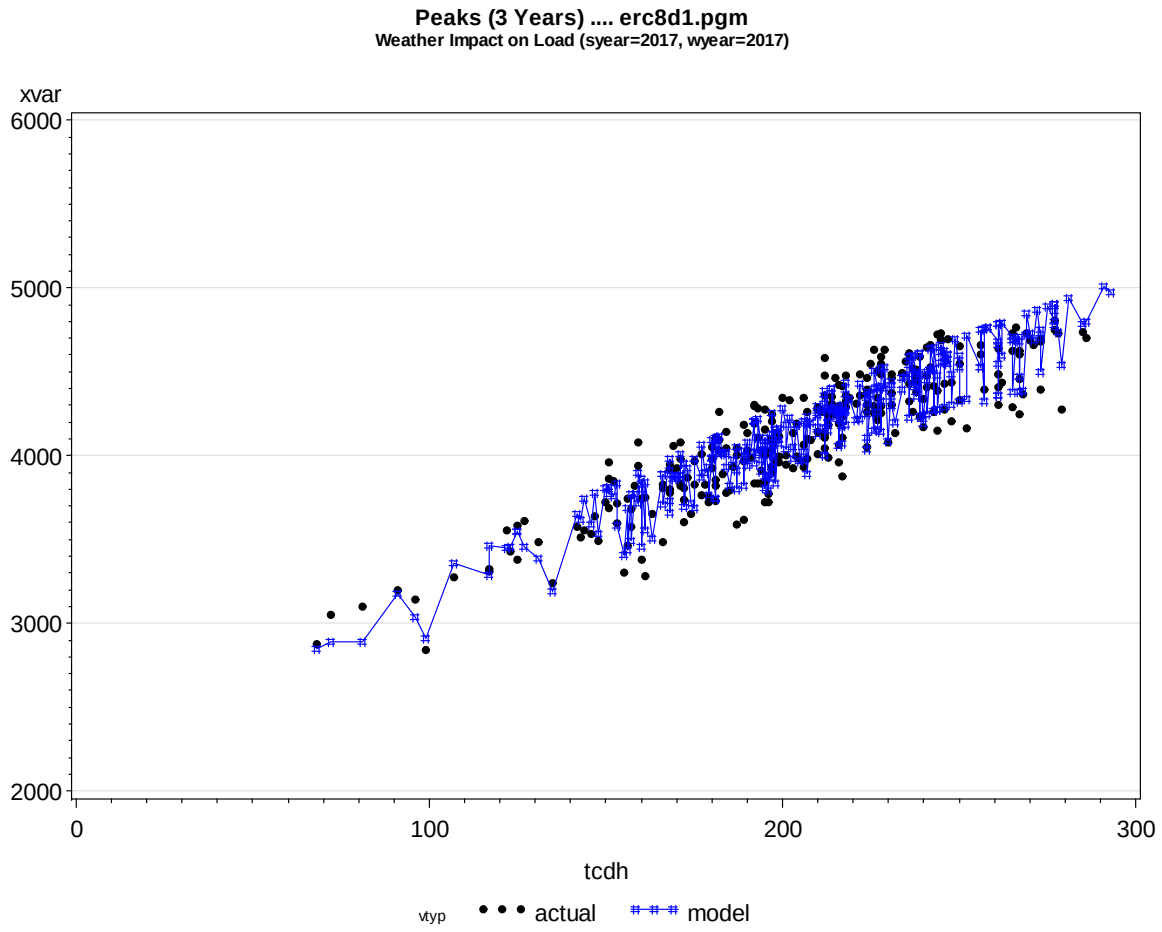


The following chart compares the winter regression model's daily peak estimates to the actual daily peak demands.



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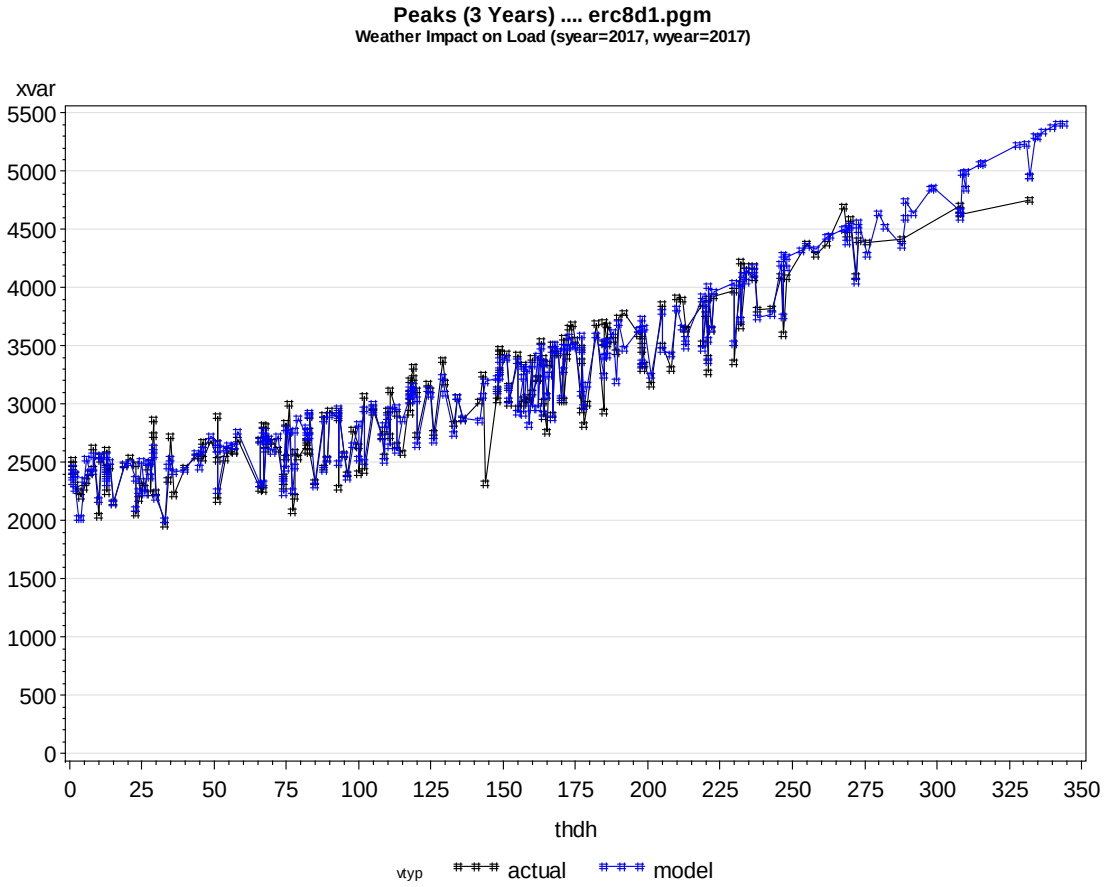


The next step was to use these regression equations to estimate what the peak demand would be on SCE&G's system today given the weather that occurred on historical peak days since 1991. The following two charts display the regression equation, the resulting peak demands and where they fall along the regression line. The first chart is for the summer season and the second for the winter season.



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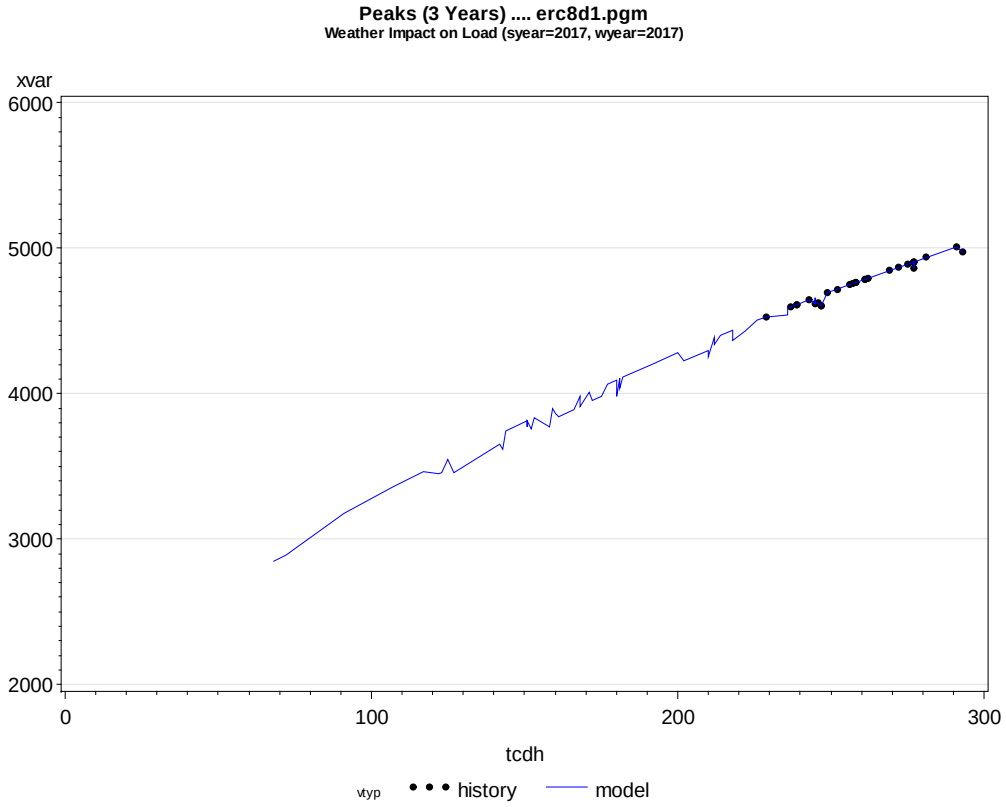


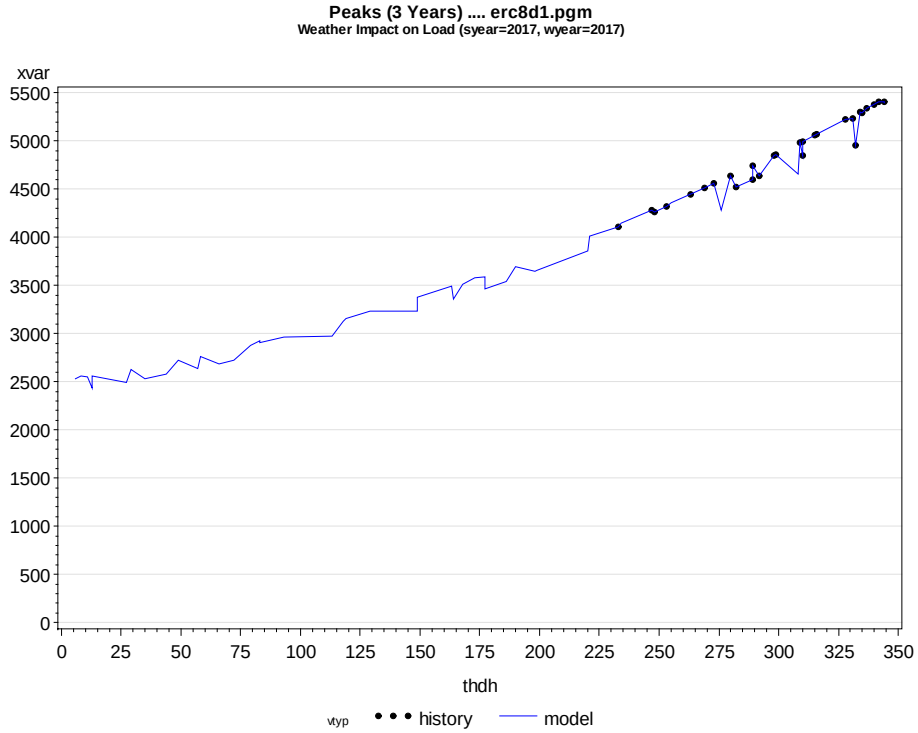




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The following table, Table 1, shows the maximum peak demand that would result from the most extreme weather since 1991. The table also shows the average peak demand which represents the peak demand expected under normal or average weather conditions today. Finally, the table shows the maximum deviation from normal that could occur on SCE&G's system due to abnormal weather. The results in Table 1 are for the regression models that are based on all the days in the season where degree hours were positive. The results suggest that the summer demand risk is about 245 MW while the winter demand risk is about 556 MW.

**Table 1**

| MW Peak Demand | | | | |
|---|---|---|---|---|
| **Weather** | **Maximum** | **Normal** | **Deviation** | **%Deviation** |
| **Summer** | **5,008** | **4,763** | **245** | **5.1%** |
| **Winter** | **5,408** | **4,852** | **556** | **11.5%** |

Table 1a shows the results for the two alternate summer models, one quadratic and one linear, and both based on the 100 hottest days in the season. The demand risk based on the quadratic model is 252 MW while for the linear model the demand risk is 292 MW. The linear estimate is higher than the quadratic because the regression procedure estimated a concave down quadratic function, i.e., the impact of weather moderates as the days get hotter. In a sense the linear model overshoots the quadratic.

**Table 1a**

| Summer Models Results Using 100 Hottest Days MW Peak Demand | | | | |
|---|---|---|---|---|
| **Weather** | **Maximum** | **Normal** | **Deviation** | **%Deviation** |
| **Summer Quadratic** | **4,900** | **4,648** | **252** | **5.4%** |
| **Summer Linear** | **4,954** | **4,662** | **292** | **6.3%** |

Similar data is presented in Table 1b for the two alternate winter models, again both based on the 100 coldest days in the season. The demand risk based on the quadratic model is 617 MW while for the linear model the demand risk is 509 MW. The linear estimate is lower than the quadratic because the regression procedure estimated a concave up quadratic function, i.e., the impact of weather increases as the days get colder. In a sense the linear model undershoots the quadratic.



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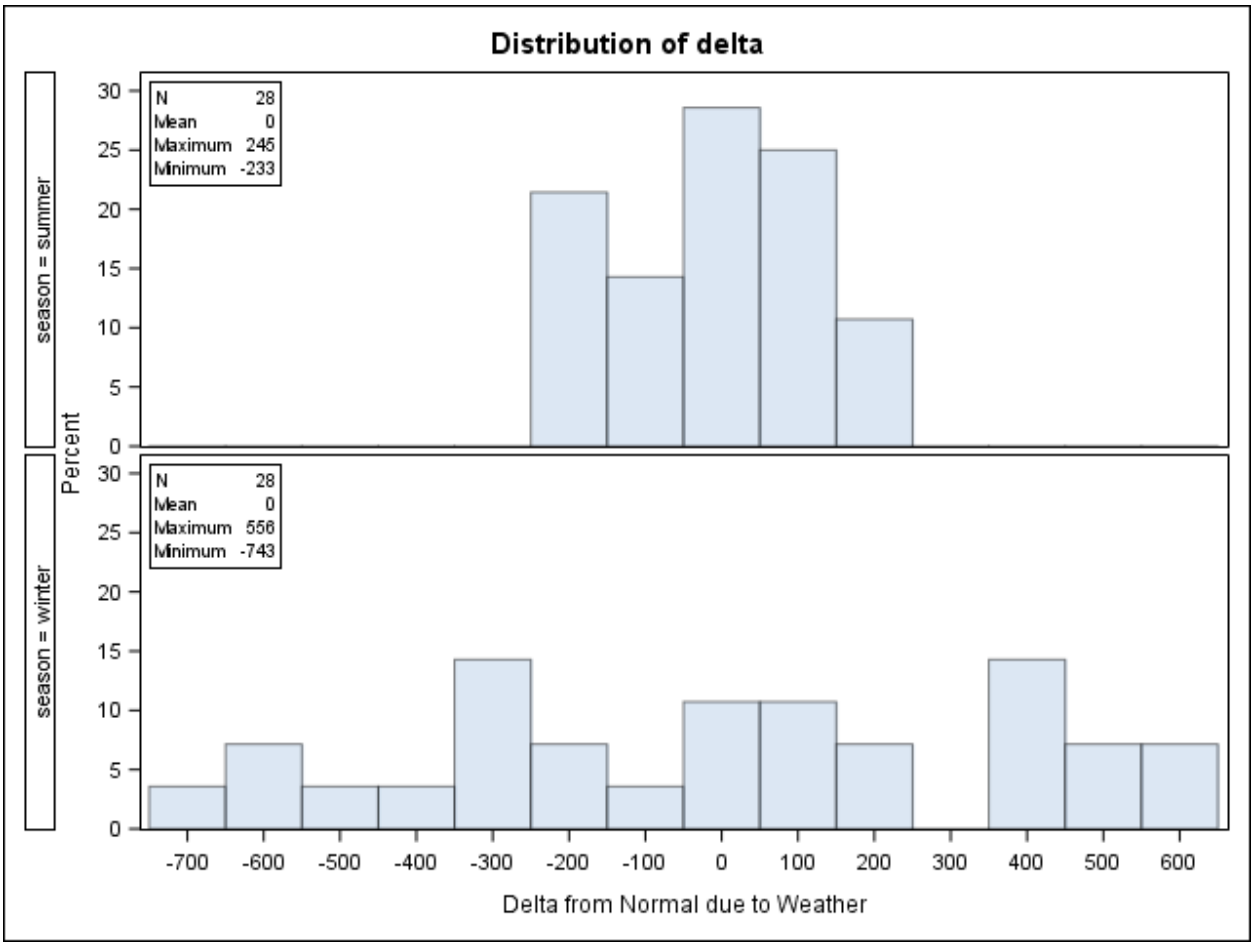
**Table 1b**

| Winter Models Results Using 100 Coldest Days MW Peak Demand | | | | |
|---|---|---|---|---|
| **Weather** | **Maximum** | **Normal** | **Deviation** | **%Deviation** |
| **Winter Quadratic** | **5,484** | **4,867** | **617** | **12.7%** |
| **Winter Linear** | **5,292** | **4,783** | **509** | **10.6%** |

There are thus three estimates of demand side risk for the summer, i.e. the base level of 245 MWs and the two alternate estimates of 252 MW and 292 MW. For the winter season the base estimate is 556 MW while the two alternates are 617 MW and 509 MW.

The following chart shows the distribution of deviations about the mean using the quadratic model based on all days in the season. 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 the winter is more spread out and similar to a uniform probability distribution.



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The following table, Table 2, summarizes the risk of higher peak demands based on these distributions.

**Table 2**

| MW Weather Deviations by Percentile | | | | |
|---|---|---|---|---|
| **Percentile** | **75%** | **90%** | **95%** | **100%** |
| **Summer** | **118** | **173** | **214** | **245** |
| **Winter** | **379** | **527** | **553** | **556** |

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 556 MW while in summer the maximum deviation is closer to 245 MW.

**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 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 2010-2017. For winter, the months of December, January and February were used. The resulting number of days used for summer and for winter was greater than 700 each season. Table 3 below summarizes each of these distributions of forced outages. For example, in summer it would take 234 MW of reserve capacity to replace the capacity forced out over 70% of the summer days being studied.

**Table 3**

| MW Forced Out by Percentile | | | | | | |
|---|---|---|---|---|---|---|
| **Percentile** | **50%** | **60%** | **70%** | **80%** | **90%** | **100%** |
| **Summer** | **106** | **152** | **234** | **385** | **618** | **1,402** |
| **Winter** | **121** | **165** | **223** | **373** | **520** | **1,552** |

The following is the distribution in graphical form showing the accumulated MW out by the percentile in the probability distribution.



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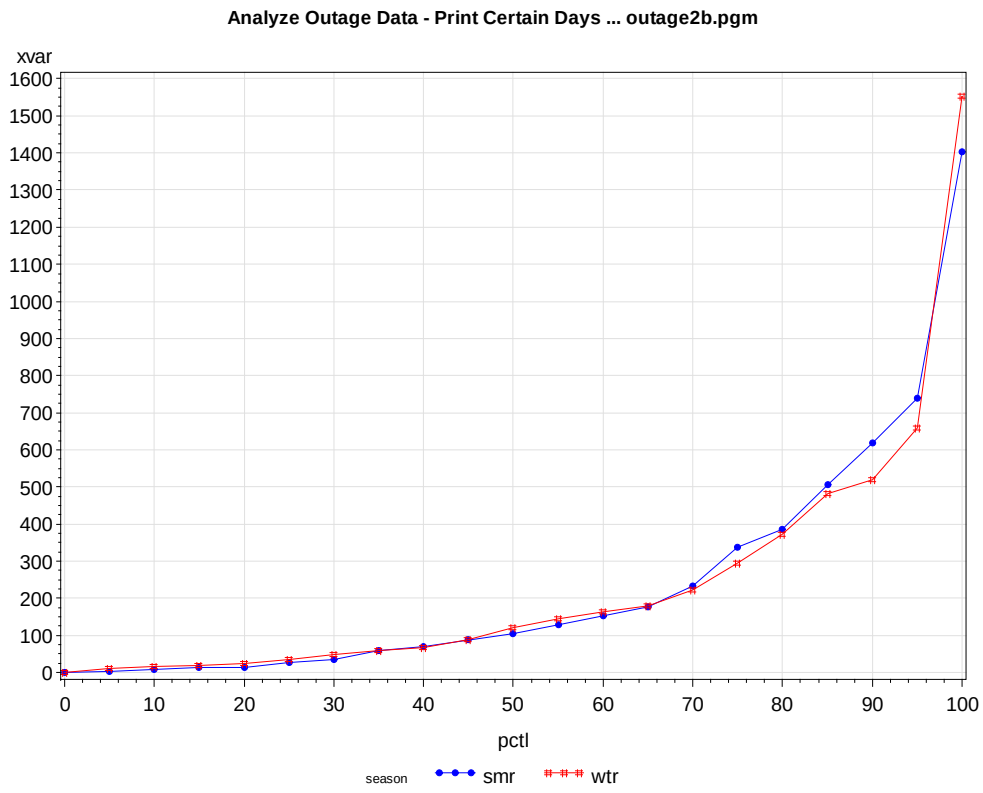


To maintain reliability and replace the loss of generating capacity up to 70% of the days in the winter, SCE&G estimates that it needs about 223 MW of reserve capacity.

**<u>Summary: Reserve Capacity for Summer and Winter Peak Periods</u>**

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.



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**Table 4**

| Reserve Margin for Summer and Winter Peak Periods | | |
|---|---|---|
| | **Summer** | **Winter** |
| **VACAR Operating** | **200** | **200** |
| **Demand-Side Risk** | **245** | **556** |
| **Supply-Side Risk** | **234** | **223** |
| **Total Reserve MWs** | **679** | **979** |
| **Normal Peak Demand** | **4,763** | **4,852** |
| **Reserve Margin %** | **14.3%** | **20.2%** |
| **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.

**<u>Base Reserve Capacity Needed to Operate the System Reliably Throughout the Year</u>**

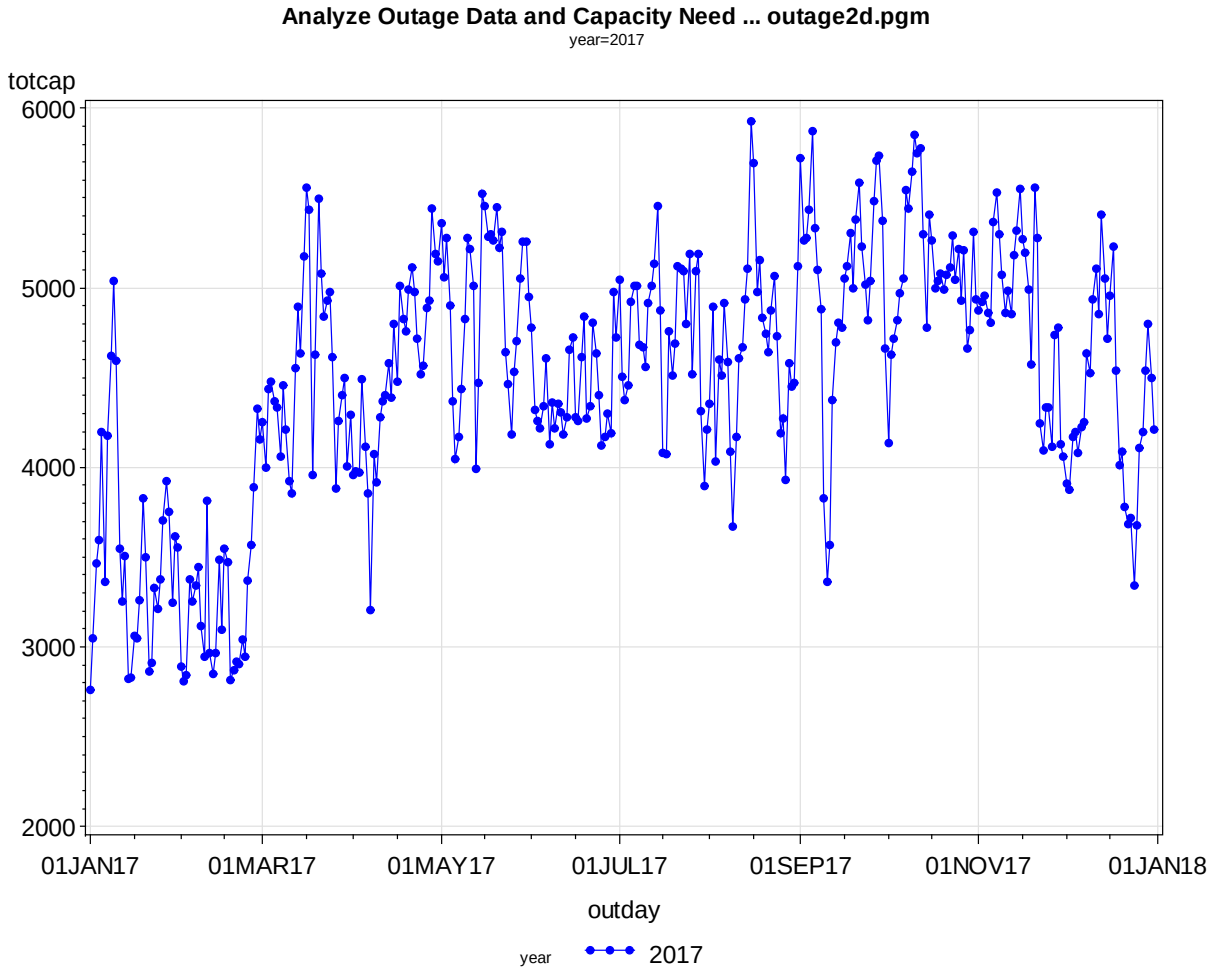
In addition to the reserves needed to address risk during the summer and winter peak periods, SCE&G needs a portion of this reserve capacity to operate the system throughout the year, not only to meet the load, but also to cover both scheduled and un-scheduled generating unit outages. To quantify this 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 — MW Forced Out — MW 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 + MW Forced Out + MW Scheduled Out + Desired Daily Reserves**

Setting the "Desired Daily Reserves" equal to the VACAR Operating Reserve requirement which is about 200 MW, 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 2017.




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 6,000 MW was principally caused by the forced outage of Williams Station on that day.



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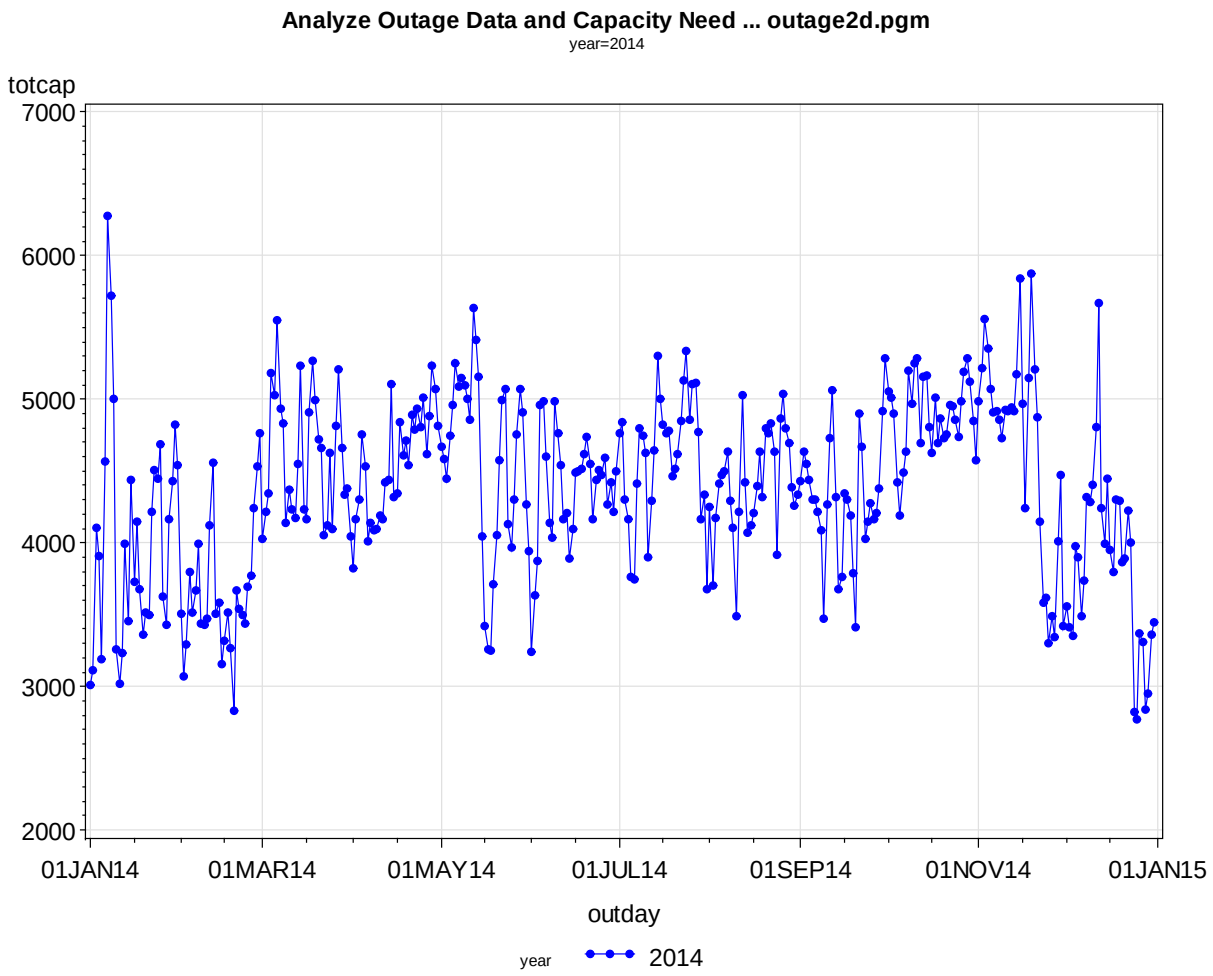


The daily capacity need for each year from 2010 to 2017 was calculated by season. Each year and season were considered a separate distribution of daily need and from each distribution the 95th, 96th and 97th percentiles were extracted. These percentiles represented the amount of capacity needed to serve 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 in tabular form. The table below shows the average of these percentiles from the seven years studied. For example, in the summer, SCE&G needs about 5,309 MW of capacity to serve 95% of the days in the summer period while 5,406 MW 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.



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**Table 5**

| Distribution of Daily Capacity Need at Certain Percentiles (MW) | | | | |
|---|---|---|---|---|
| **Percentile** | **95%** | **96%** | **97%** | **100%** |
| **Summer** | **5,309** | **5,359** | **5,406** | **5,735** |
| **Winter** | **5,148** | **5,217** | **5,333** | **5,723** |

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 13.40% for summer and 14.95% for winter. SCE&G believes these results support the existing 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%** |
| **Summer** | **12.4** | **13.5** | **14.4** | **21.4** |
| **Winter** | **12.9** | **14.4** | **17.0** | **25.6** |

**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%** |

# APPENDICES

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## Appendix A1- Stepwise Selection Results for Best Model in the Summer Season

Following is the SAS programming code showing the variables used in the stepwise variable selection process that identified the best regression model to use. The first set of SAS results are based on all days in the summer season while the second set is restricted to the 100 hottest days in the season.

```
proc reg;
model mxload=ihol wkend cdh cdh2
        yrlag1 yrlag2 imo6-imo8 idow1-idow7
  /slstay=0.15 slentry=0.15 selection=stepwise ss2 sse aic;
```

All variables left in the model are significant at the 0.1500 level.

No other variable met the 0.1500 significance level for entry into the model.

Summary of Stepwise Selection

| Step | Variable Entered | Variable Removed | Number Vars In | Partial R-Square | Model R-Square | C(p) | F Value | Pr > F |
|---|---|---|---|---|---|---|---|---|
| 1 | cdh | | 1 | 0.8106 | 0.8106 | 408.727 | 1172.53 | <.0001 |
| 2 | wkend | | 2 | 0.0754 | 0.8860 | 139.715 | 180.58 | <.0001 |
| 3 | imo6 | | 3 | 0.0081 | 0.8941 | 112.642 | 20.77 | <.0001 |
| 4 | ihol | | 4 | 0.0079 | 0.9020 | 86.3367 | 21.77 | <.0001 |
| 5 | yrlag1 | | 5 | 0.0061 | 0.9081 | 66.3849 | 17.94 | <.0001 |
| 6 | yrlag2 | | 6 | 0.0120 | 0.9200 | 25.3887 | 40.25 | <.0001 |
| 7 | cdh2 | | 7 | 0.0042 | 0.9242 | 12.4056 | 14.74 | 0.0002 |
| 8 | idow6 | | 8 | 0.0018 | 0.9260 | 8.1142 | 6.31 | 0.0126 |

All variables left in the model are significant at the 0.1500 level.

No other variable met the 0.1500 significance level for entry into the model.

Summary of Stepwise Selection

| Step | Variable Entered | Variable Removed | Number Vars In | Partial R-Square | Model R-Square | C(p) | F Value | Pr > F |
|---|---|---|---|---|---|---|---|---|
| 1 | cdh | | 1 | 0.8653 | 0.8653 | 145.354 | 629.58 | <.0001 |
| 2 | wkend | | 2 | 0.0706 | 0.9359 | 20.8063 | 106.92 | <.0001 |
| 3 | idow6 | | 3 | 0.0094 | 0.9453 | 6.0321 | 16.43 | 0.0001 |
| 4 | cdh2 | | 4 | 0.0034 | 0.9487 | 1.9710 | 6.26 | 0.0141 |
| 5 | ihol | | 5 | 0.0020 | 0.9506 | 0.4719 | 3.72 | 0.0569 |



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## Appendix A2

## Best Regression Equation for Daily Summer Peak Demand Using All Days in the Season

Peaks (3 Years) .... erc8d1.pgm
Weather Impact on Load (syear=2017, wyear=2017)

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

| | |
|---|---|
| Number of Observations Read | 304 |
| Number of Observations Used | 276 |
| Number of Observations with Missing Values | 28 |

Weight: wgts Weight

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 8 | 36958412 | 4619801 | 440.80 | <.0001 |
| Error | 267 | 2798296 | 10481 | | |
| Corrected Total | 275 | 39756708 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 102.37437 | R-Square | 0.9296 |
| Dependent Mean | 4116.35770 | Adj R-Sq | 0.9275 |
| Coeff Var | 2.48701 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 4314.05871 | 13.82104 | 312.14 | <.0001 | 0 |
| ihol | 1 | -309.29412 | 59.87563 | -5.17 | <.0001 | 1.01487 |
| wkend | 1 | -252.57647 | 14.42786 | -17.51 | <.0001 | 1.09179 |
| cdh | 1 | 8.87928 | 0.17995 | 49.34 | <.0001 | 1.40974 |
| cdh2 | 1 | -1.04225 | 0.25947 | -4.02 | <.0001 | 1.15437 |
| yrlag1 | 1 | -127.38431 | 16.87435 | -7.55 | <.0001 | 1.63914 |
| yrlag2 | 1 | -106.65340 | 15.91125 | -6.70 | <.0001 | 1.45026 |
| imo6 | 1 | -70.01001 | 13.60334 | -5.15 | <.0001 | 1.05026 |
| idow6 | 1 | -44.79588 | 18.42714 | -2.43 | 0.0157 | 1.07727 |

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## Appendix A3

### Best Regression Equation for Daily Summer Peak Demand Using 100 Hottest Days

Peaks (3 Years) .... erc8d1.pgm
Weather Impact on Load (syear=2017, wyear=2017)

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

| | |
|---|---|
| Number of Observations Read | 128 |
| Number of Observations Used | 100 |
| Number of Observations with Missing Values | 28 |

Weight: wgts Weight

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 5 | 16342711 | 3268542 | 388.89 | <.0001 |
| Error | 94 | 790053 | 8404.81960 | | |
| Corrected Total | 99 | 17132764 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 91.67780 | R-Square | 0.9539 |
| Dependent Mean | 4169.53027 | Adj R-Sq | 0.9514 |
| Coeff Var | 2.19876 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 4272.15775 | 14.07452 | 303.54 | <.0001 | 0 |
| ihol | 1 | -202.30607 | 97.28648 | -2.08 | 0.0403 | 1.11453 |
| wkend | 1 | -282.53890 | 22.25120 | -12.70 | <.0001 | 1.08378 |
| cdh | 1 | 8.71227 | 0.23552 | 36.99 | <.0001 | 1.15184 |
| cdh2 | 1 | -0.93290 | 0.38207 | -2.44 | 0.0165 | 1.13206 |
| idow6 | 1 | -99.93867 | 27.37706 | -3.65 | 0.0004 | 1.12739 |

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## Appendix A4

## Linear Regression Equation for Daily Summer Peak Demand Using 100 Hottest Days

Peaks (3 Years) .... erc8d1.pgm
Weather Impact on Load (syear=2017, wyear=2017)

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

| | |
|---|---|
| Number of Observations Read | 128 |
| Number of Observations Used | 100 |
| Number of Observations with Missing Values | 28 |

Weight: wgts Weight

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 4 | 16370772 | 4092693 | 457.22 | <.0001 |
| Error | 95 | 850370 | 8951.25977 | | |
| Corrected Total | 99 | 17221142 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 94.61110 | R-Square | 0.9506 |
| Dependent Mean | 4165.91046 | Adj R-Sq | 0.9485 |
| Coeff Var | 2.27108 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 4254.01278 | 12.45681 | 341.50 | <.0001 | 0 |
| ihol | 1 | -224.08993 | 99.85492 | -2.24 | 0.0271 | 1.10254 |
| wkend | 1 | -279.47519 | 22.75927 | -12.28 | <.0001 | 1.07635 |
| cdh | 1 | 8.90539 | 0.23218 | 38.36 | <.0001 | 1.04926 |
| idow6 | 1 | -100.91267 | 28.19402 | -3.58 | 0.0005 | 1.12780 |

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## Appendix B1- Stepwise Selection Results for Best Model in the Winter Season

Following is the SAS programming code showing the variables used in the stepwise variable selection process that identified the best regression model to use. The first set of SAS results are based on all days in the winter season while the second set is restricted to the 100 coldest days in the season.

```
proc reg;
model mxload=wtr18 wtr17 wtr16 ihol wkend hdh hdh2
        yrlag1 yrlag2 imo1 imo2 imo3 idow1-idow7
  /slstay=0.15 slentry=0.15 selection=stepwise ss2 sse aic;
```

All variables left in the model are significant at the 0.1500 level.

No other variable met the 0.1500 significance level for entry into the model.

Summary of Stepwise Selection

| Step | Variable Entered | Variable Removed | Number Vars In | Partial R-Square | Model R-Square | C(p) | F Value | Pr > F |
|---|---|---|---|---|---|---|---|---|
| 1 | hdh | | 1 | 0.8352 | 0.8352 | 532.253 | 1120.02 | <.0001 |
| 2 | wkend | | 2 | 0.0725 | 0.9077 | 203.735 | 172.83 | <.0001 |
| 3 | hdh2 | | 3 | 0.0219 | 0.9296 | 106.044 | 68.00 | <.0001 |
| 4 | ihol | | 4 | 0.0069 | 0.9365 | 76.6485 | 23.63 | <.0001 |
| 5 | yrlag1 | | 5 | 0.0052 | 0.9416 | 55.0161 | 19.28 | <.0001 |
| 6 | imo1 | | 6 | 0.0036 | 0.9452 | 40.7737 | 14.05 | 0.0002 |
| 7 | imo2 | | 7 | 0.0039 | 0.9491 | 24.9199 | 16.55 | <.0001 |
| 8 | wtr18 | | 8 | 0.0031 | 0.9522 | 12.7940 | 13.88 | 0.0002 |
| 9 | yrlag2 | | 9 | 0.0013 | 0.9535 | 9.0749 | 5.74 | 0.0174 |
| 10 | idow3 | | 10 | 0.0005 | 0.9540 | 8.6530 | 2.45 | 0.1191 |

All variables left in the model are significant at the 0.1500 level.

No other variable met the 0.1500 significance level for entry into the model.

Summary of Stepwise Selection

| Step | Variable Entered | Variable Removed | Number Vars In | Partial R-Square | Model R-Square | C(p) | F Value | Pr > F |
|---|---|---|---|---|---|---|---|---|
| 1 | hdh | | 1 | 0.7535 | 0.7535 | 230.492 | 299.51 | <.0001 |
| 2 | wkend | | 2 | 0.1388 | 0.8923 | 48.6584 | 125.00 | <.0001 |
| 3 | imo1 | | 3 | 0.0067 | 0.8990 | 41.7633 | 6.38 | 0.0132 |
| 4 | ihol | | 4 | 0.0067 | 0.9057 | 34.8551 | 6.78 | 0.0107 |
| 5 | imo2 | | 5 | 0.0060 | 0.9117 | 28.8815 | 6.41 | 0.0130 |
| 6 | wtr18 | | 6 | 0.0049 | 0.9166 | 24.3910 | 5.47 | 0.0215 |
| 7 | idow4 | | 7 | 0.0033 | 0.9199 | 22.0204 | 3.79 | 0.0545 |
| 8 | yrlag2 | | 8 | 0.0036 | 0.9236 | 19.1870 | 4.35 | 0.0399 |
| 9 | yrlag1 | | 9 | 0.0071 | 0.9307 | 11.8382 | 9.16 | 0.0032 |
| 10 | idow5 | | 10 | 0.0022 | 0.9328 | 10.9465 | 2.89 | 0.0924 |
| 11 | hdh2 | | 11 | 0.0019 | 0.9347 | 10.4392 | 2.55 | 0.1137 |

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## Appendix B2

## Best Regression Equation for Daily Winter Peak Demand Using All Days in the Season

Peaks (3 Years) .... erc8d1.pgm
Weather Impact on Load (syear=2017, wyear=2017)

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

| | |
|---|---|
| Number of Observations Read | 251 |
| Number of Observations Used | 223 |
| Number of Observations with Missing Values | 28 |

Weight: wgts Weight

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 9 | 82329996 | 9147777 | 701.23 | <.0001 |
| Error | 213 | 2778673 | 13045 | | |
| Corrected Total | 222 | 85108669 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 114.21652 | R-Square | 0.9674 |
| Dependent Mean | 3070.71806 | Adj R-Sq | 0.9660 |
| Coeff Var | 3.71954 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 3077.82868 | 20.10871 | 153.06 | <.0001 | 0 |
| wtr18 | 1 | -315.82025 | 71.15093 | -4.44 | <.0001 | 1.44678 |
| ihol | 1 | -401.70093 | 59.45998 | -6.76 | <.0001 | 1.03161 |
| wkend | 1 | -376.03592 | 17.59272 | -21.37 | <.0001 | 1.04141 |
| hdh | 1 | 7.17788 | 0.11225 | 63.94 | <.0001 | 1.29907 |
| hdh2 | 1 | 1.40804 | 0.13546 | 10.39 | <.0001 | 1.38861 |
| yrlag1 | 1 | -123.94243 | 19.80997 | -6.26 | <.0001 | 1.43720 |
| yrlag2 | 1 | -64.29258 | 20.10490 | -3.20 | 0.0016 | 1.43045 |
| imo1 | 1 | 144.31807 | 19.91338 | 7.25 | <.0001 | 1.51943 |
| imo2 | 1 | 120.63311 | 20.44786 | 5.90 | <.0001 | 1.42949 |

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## Appendix B3

## Best Regression Equation for Daily Winter Peak Demand Using 100 Coldest Days

Peaks (3 Years) .... erc8d1.pgm
Weather Impact on Load (syear=2017, wyear=2017)

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

| | |
|---|---|
| Number of Observations Read | 128 |
| Number of Observations Used | 100 |
| Number of Observations with Missing Values | 28 |

Weight: wgts Weight

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 11 | 21605105 | 1964100 | 127.98 | <.0001 |
| Error | 88 | 1350561 | 15347 | | |
| Corrected Total | 99 | 22955667 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 123.88418 | R-Square | 0.9412 |
| Dependent Mean | 3623.34836 | Adj R-Sq | 0.9338 |
| Coeff Var | 3.41905 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 3662.44166 | 36.09219 | 101.47 | <.0001 | 0 |
| wtr18 | 1 | -356.50387 | 94.87557 | -3.76 | 0.0003 | 2.24954 |
| ihol | 1 | -435.52549 | 128.52510 | -3.39 | 0.0011 | 1.06526 |
| wkend | 1 | -355.02221 | 29.57414 | -12.00 | <.0001 | 1.22204 |
| hdh | 1 | 9.36800 | 0.39523 | 23.70 | <.0001 | 1.84796 |
| hdh2 | 1 | 1.30843 | 0.80204 | 1.63 | 0.1064 | 2.90784 |
| yrlag1 | 1 | -106.43984 | 35.24151 | -3.02 | 0.0033 | 1.47493 |
| yrlag2 | 1 | -98.67824 | 32.57139 | -3.03 | 0.0032 | 1.56975 |
| imo1 | 1 | 151.79067 | 33.96911 | 4.47 | <.0001 | 1.82665 |
| imo2 | 1 | 138.28224 | 37.92080 | 3.65 | 0.0004 | 1.61805 |
| idow4 | 1 | 129.82219 | 44.63422 | 2.91 | 0.0046 | 1.16459 |
| idow5 | 1 | 73.62491 | 41.37926 | 1.78 | 0.0786 | 1.17357 |

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## Appendix B4

## Linear Regression Equation for Daily Winter Peak Demand Using 100 Coldest Days

Peaks (3 Years) .... erc8d1.pgm
Weather Impact on Load (syear=2017, wyear=2017)

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

| | |
|---|---|
| Number of Observations Read | 128 |
| Number of Observations Used | 100 |
| Number of Observations with Missing Values | 28 |

Weight: wgts Weight

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 10 | 21630957 | 2163096 | 137.39 | <.0001 |
| Error | 89 | 1401264 | 15745 | | |
| Corrected Total | 99 | 23032221 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 125.47723 | R-Square | 0.9392 |
| Dependent Mean | 3622.83771 | Adj R-Sq | 0.9323 |
| Coeff Var | 3.46351 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| | Variance Inflation |
|---|---|---|---|---|---|---|
| Intercept | 1 | 3683.49549 | 34.38143 | 107.14 | <.0001 | 0 |
| wtr18 | 1 | -265.97943 | 76.53139 | -3.48 | 0.0008 | 1.42695 |
| ihol | 1 | -463.11021 | 129.08845 | -3.59 | 0.0005 | 1.04753 |
| wkend | 1 | -357.38178 | 29.85925 | -11.97 | <.0001 | 1.21722 |
| hdh | 1 | 9.63809 | 0.37173 | 25.93 | <.0001 | 1.59300 |
| yrlag1 | 1 | -102.01486 | 35.49664 | -2.87 | 0.0051 | 1.46661 |
| yrlag2 | 1 | -110.16577 | 32.27602 | -3.41 | 0.0010 | 1.50360 |
| imo1 | 1 | 161.91774 | 33.47049 | 4.84 | <.0001 | 1.73247 |
| imo2 | 1 | 137.88242 | 38.29822 | 3.60 | 0.0005 | 1.60778 |
| idow4 | 1 | 117.78909 | 44.56174 | 2.64 | 0.0097 | 1.13181 |
| idow5 | 1 | 71.81312 | 41.87812 | 1.71 | 0.0899 | 1.17208 |

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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 | 5418.0 | 22.0 | 11.3 | 12.4 | 14.4 |
| | 2011.0 | 184.0 | 5697.5 | 4885.0 | 5418.5 | 5470.0 | 5492.0 | 16.6 | 10.9 | 12.0 | 12.4 |
| | 2012.0 | 184.0 | 6181.5 | 4761.0 | 5224.5 | 5256.5 | 5299.5 | 29.8 | 9.7 | 10.4 | 11.3 |
| | 2013.0 | 184.0 | 5645.0 | 4574.0 | 5264.0 | 5306.0 | 5392.5 | 23.4 | 15.1 | 16.0 | 17.9 |
| | 2014.0 | 184.0 | 5636.5 | 4594.0 | 5195.5 | 5254.5 | 5286.5 | 22.7 | 13.1 | 14.4 | 15.1 |
| | 2015.0 | 184.0 | 5386.0 | 4750.0 | 5115.0 | 5167.0 | 5197.5 | 13.4 | 7.7 | 8.8 | 9.4 |
| | 2016.0 | 184.0 | 5631.5 | 4807.0 | 5343.0 | 5393.5 | 5425.5 | 17.2 | 11.2 | 12.2 | 12.9 |
| | 2017.0 | 184.0 | 5927.5 | 4697.0 | 5646.5 | 5705.5 | 5734.5 | 26.2 | 20.2 | 21.5 | 22.1 |
| summer | | 184.0 | 5735.4 | 4725.4 | 5309.4 | 5359.4 | 5405.8 | 21.4 | 12.4 | 13.5 | 14.4 |
| 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 | 5641.5 | 4868.0 | 5017.5 | 5043.0 | 5135.0 | 15.9 | 3.1 | 3.6 | 5.5 |
| | 2012.0 | 182.0 | 5832.5 | 4397.0 | 5316.0 | 5379.0 | 5426.5 | 32.6 | 20.9 | 22.3 | 23.4 |
| | 2013.0 | 181.0 | 5958.5 | 3984.0 | 4920.5 | 5078.0 | 5389.5 | 49.6 | 23.5 | 27.5 | 35.3 |
| | 2014.0 | 181.0 | 6272.5 | 4853.0 | 5235.0 | 5349.5 | 5560.5 | 29.2 | 7.9 | 10.2 | 14.6 |
| | 2015.0 | 181.0 | 5601.5 | 4970.0 | 5082.0 | 5116.5 | 5251.5 | 12.7 | 2.3 | 2.9 | 5.7 |
| | 2016.0 | 182.0 | 5632.0 | 4409.0 | 5286.5 | 5315.5 | 5357.0 | 27.7 | 19.9 | 20.6 | 21.5 |
| | 2017.0 | 181.0 | 5561.0 | 4457.0 | 5316.0 | 5406.0 | 5442.5 | 24.8 | 19.3 | 21.3 | 22.1 |
| winter | | 181.3 | 5723.1 | 4582.0 | 5147.7 | 5217.1 | 5333.1 | 25.6 | 12.9 | 14.4 | 17.0 |

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**Exhibit No. __ (JML-4)**

# Loss of Load Expectation Study

SCE&G is becoming Dominion Energy®

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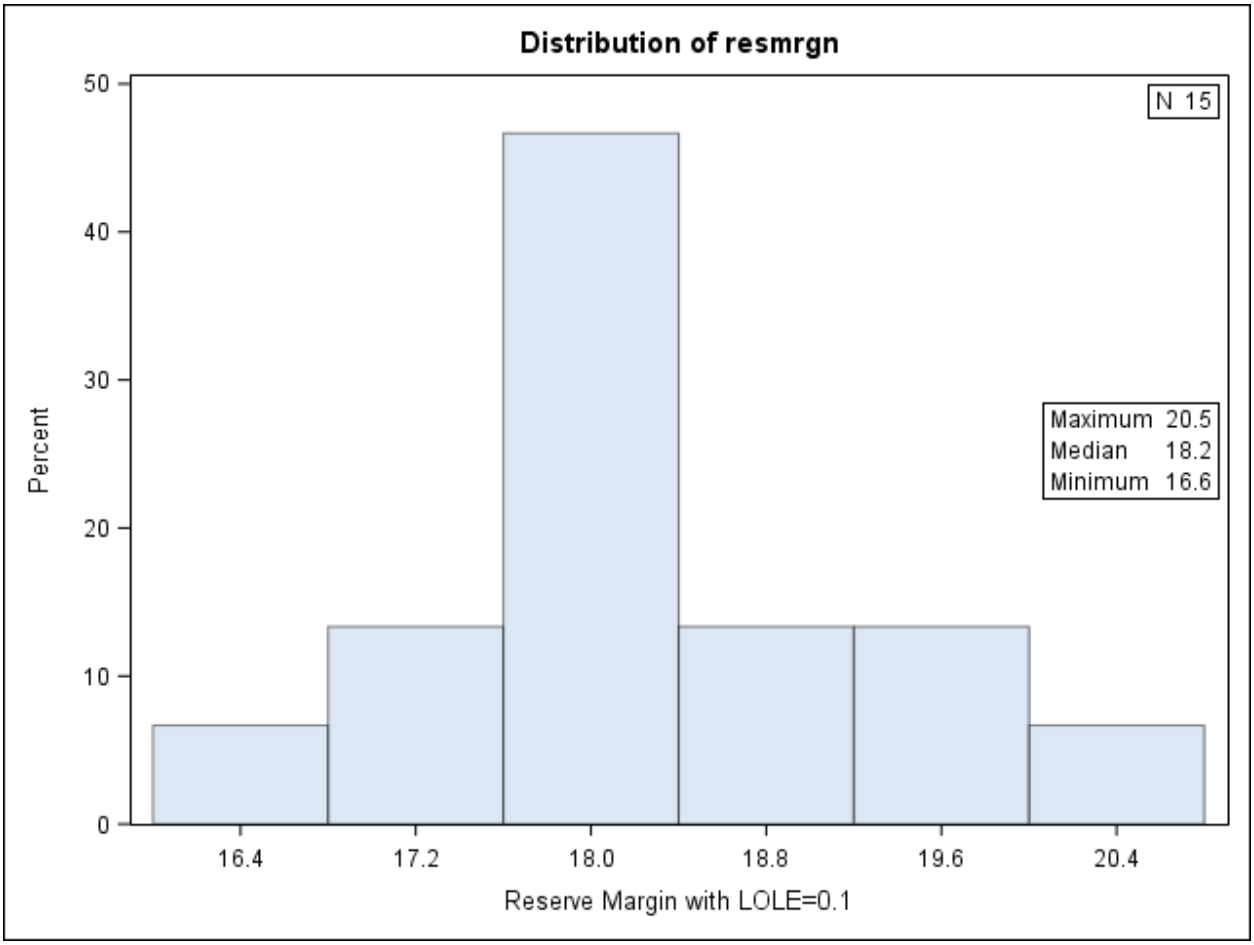
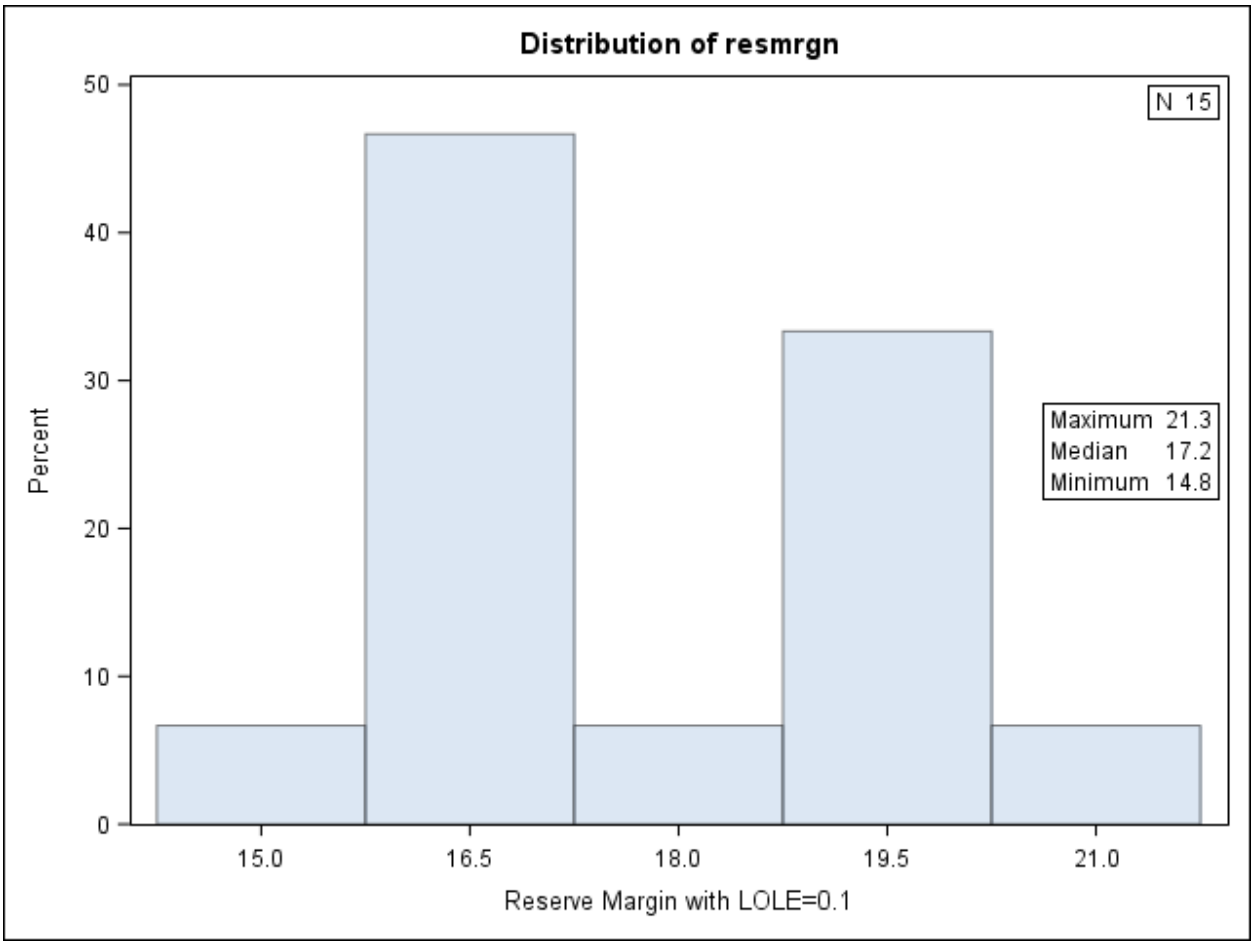
**Executive Summary**

The Loss of Load Expectation ("LOLE") reliability index was calculated using the adjusted profiles from the last 15 years, 2004-2018. The goal of the study was to calculate the relationship on SCE&G's system between reserve margin and LOLE, thereby deriving the reserve margin equivalent to an LOLE=0.1. Two studies were run: one using an adjustment based on seasonal peaks, the "peak" method, and a second using an adjustment based on energy, the "energy" method. The following histogram summarize the results when using the peak method.




From this histogram, it can be concluded that a reserve margin between 16.6% and 20.5% is required to achieve reliability at the level represented by an LOLE=0.1, i.e., one day in 10 years. The average, or middle point, in the distribution is 18.2%.

The following histogram summarize the results when using the energy method.




From this histogram, it can be concluded that a reserve margin between 14.8% and 21.3% is required to achieve reliability at the level represented by an LOLE=0.1, i.e., one day in 10 years. The average, or middle point, in the distribution is 17.2%.

Since the LOLE index represents reliability for the whole year and is calculated using peak loads on each day of the year, it should be used to evaluate SCE&G's base reserve margin policy, i.e., having a minimum reserve margin of 14% throughout the winter season and 12% throughout the summer season. As explained later in this report, it is not appropriate to use LOLE to assess risk during extreme weather events. Using the LOLE methodology, a 14% reserve margin equates to about an LOLE=0.3, i.e., 3 days in 10 years. However, SCE&G mitigates much of this apparent risk, i.e., 0.3 vs 0.1 LOLE, by its use of peaking reserves which should be available for a few peak days each season.

## Introduction

The LOLE methodology basically has three steps: 1) prepare the normalized daily peak load data; 2) calculate the capacity outage probability table ("COPT") which associates a probability to a level of outage; and 3) using the daily peaks and the COPT compute the expected number of days of outage, i.e., the LOLE index. The industry standard for reliability sets the LOLE



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at 0.1 which equates to an expectation of 1 day of outage every 10 years and is known as the "1 in 10" criterion.

It is also worth noting that the term loss of load probability ("LOLP") is often used interchangeably with LOLE although strictly speaking LOLP is a probability and LOLE is an expected value.

**The Details**

The daily peak load data was calculated for each of the last 15 years, i.e., 2004 through 2018 under two adjustment scenarios. The first type of adjustment, the "peak" method, adjusted the daily loads from history so that their summer and winter peaks were equal to those projected for 2019, that is, the adjustment factor for daily peaks in the summer months was the ratio of the 2019 summer peak over the historical years summer peak and a similar adjustment for winter months using winter peaks. The second method, the "energy" method, adjusted historical daily peaks by the ratio of the 2019 forecasted system energy by the system energy occurring in the historical year. Summary results of these adjustments are shown in Table 1 of the appendix.

The COPT was calculated from the Company's forced outage data for the years 2010 through 2017. The forced outage rate of each generating unit was calculated and then averaged over the 8 years. The result was the effective forced outage rate, ("EFOR"), from which the COPT was created. A few small gas turbines ("GT") did not have acceptable data and their EFOR was set to 5%. Each unit is considered either available or unavailable with the probability of being unavailable equal to the EFOR. Thus, the outage status of each unit can be described by a binomial probability distribution with parameter EFOR. In this way a total of 65 binomial distributions are set up, one for each unit. To create the COPT, these probability distributions are combined using the convolution algorithm from statistical theory. The convolution algorithm requires the individual probability distributions to be statistically independent. For the most part generating units are mechanically independent, but their availability is not statistically independent since several units can be affected simultaneously by severe weather or fuel restrictions. Nevertheless, the COPT is calculated under the assumption that this independence technicality has minor influence. A summary version of the COPT table is shown as Table 2 in the appendix.

The next step was to use the daily peak loads from each year, one year at a time, and the COPT to calculate the LOLE index. Since the goal was to establish a relationship between reserve margin and LOLE on the SCE&G system, the LOLE was calculated using values of reserve margin ranging from 12% to 25% in 0.5% steps. Thus, the LOLE associated with 28 different values of reserve margin was computed for each year from 2004 to 2018. The results of these calculations are shown in Tables 3 and 4 in the appendix.

The following graph shows the relationship between reserve margin on the horizontal and the LOLE index shown on the vertical for each year in the study. This graph is for the "peak method" of adjustment. The graph for the "energy method" of adjustment would look similar.



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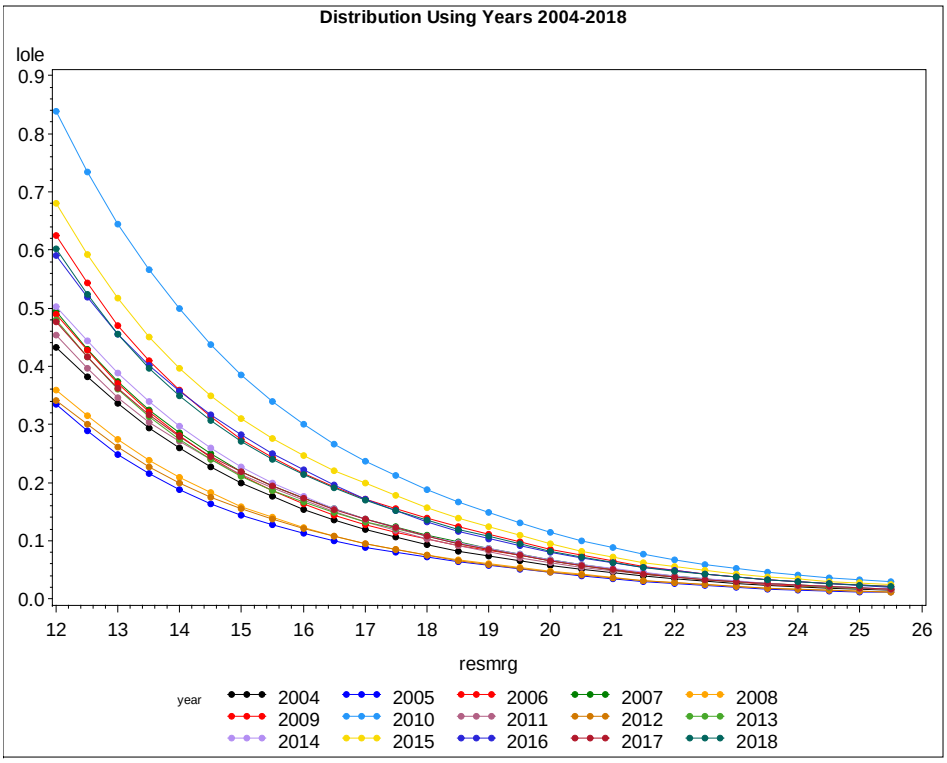
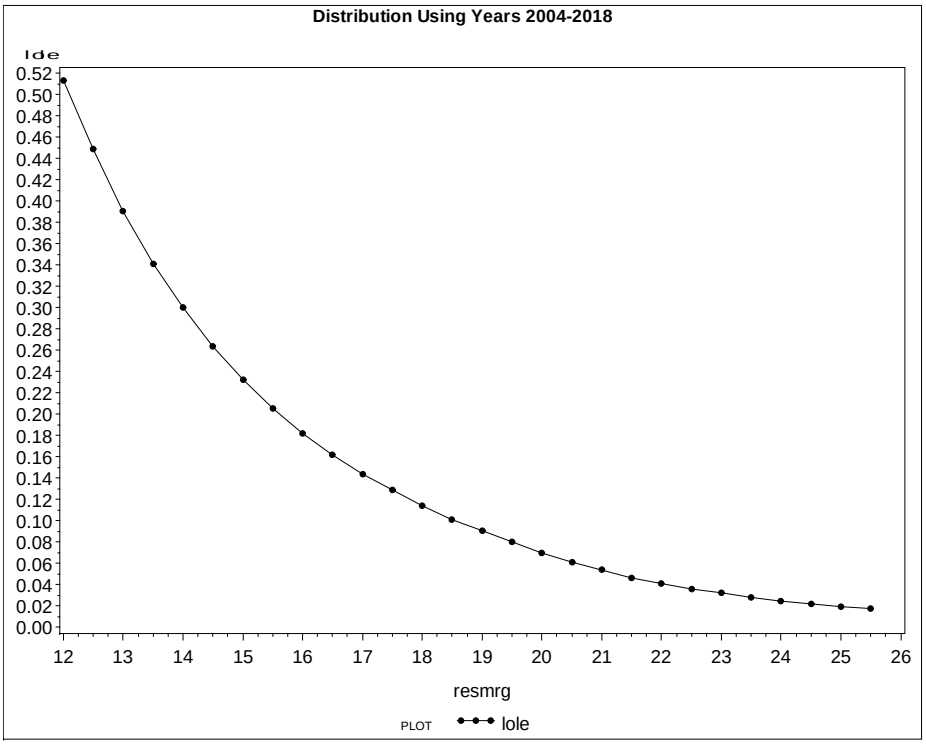



The following graph shows the average LOLE value for each reserve margin level.



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The functional relationship between LOLE and reserve margin is not linear but the relationship between the LOG(LOLE) and reserve margin is linear. The logarithm function, LOG( ), used here is the natural logarithm, i.e., with the transcendental number "e" for base. Below are the results of fitting this functional form to the data.

The REG Procedure
Model: MODEL1
Dependent Variable: resmrg

| | |
|---|---|
| Number of Observations Read | 29 |
| Number of Observations Used | 28 |
| Number of Observations with Missing Values | 1 |

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 1 | 456.62783 | 456.62783 | 97176.7 | <.0001 |
| Error | 26 | 0.12217 | 0.00470 | | |
| Corrected Total | 27 | 456.75000 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 0.06855 | R-Square | 0.9997 |
| Dependent Mean | 18.75000 | Adj R-Sq | 0.9997 |
| Coeff Var | 0.36559 | | |

Parameter Estimates

| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|---|
| Intercept | 1 | 9.23069 | 0.03317 | 278.28 | <.0001 |
| lnlole | 1 | -4.01300 | 0.01287 | -311.73 | <.0001 |

The parameter estimates in the function can be used to calculate the reserve margin level associated with an LOLE=0.1. Here are the calculations:

Reserve Margin = a + b * LOG(LOLE)
= 9.23069 – 4.01300 * LOG (0.1)
= 9.23069 – 4.01300 * (-2.30259)
= 18.5

Thus, based on the average LOLE data, an LOLE value of 0.1 requires about an 18.5% reserve margin. The equation can also be used to find the LOLE for a given reserve margin by reversing the solution process. For example, it is easy to show that SCE&G's base winter reserve margin level of 14% is associated with an LOLE=0.3 or about a 3 day in 10 LOLE level.

This same analysis using the average LOLE value for each reserve margin level can be made for the "energy method" of adjustment. Following are the regression results.

The REG Procedure
Model: MODEL1
Dependent Variable: resmrg

| | |
|---|---|
| Number of Observations Read | 29 |
| Number of Observations Used | 28 |
| Number of Observations with Missing Values | 1 |

Analysis of Variance

| Source | DF | Sum of Squares | Mean Square | F Value | Pr > F |
|---|---|---|---|---|---|
| Model | 1 | 456.63099 | 456.63099 | 99755.9 | <.0001 |
| Error | 26 | 0.11901 | 0.00458 | | |
| Corrected Total | 27 | 456.75000 | | | |

| | | | |
|---|---|---|---|
| Root MSE | 0.06766 | R-Square | 0.9997 |
| Dependent Mean | 18.75000 | Adj R-Sq | 0.9997 |
| Coeff Var | 0.36084 | | |

Parameter Estimates

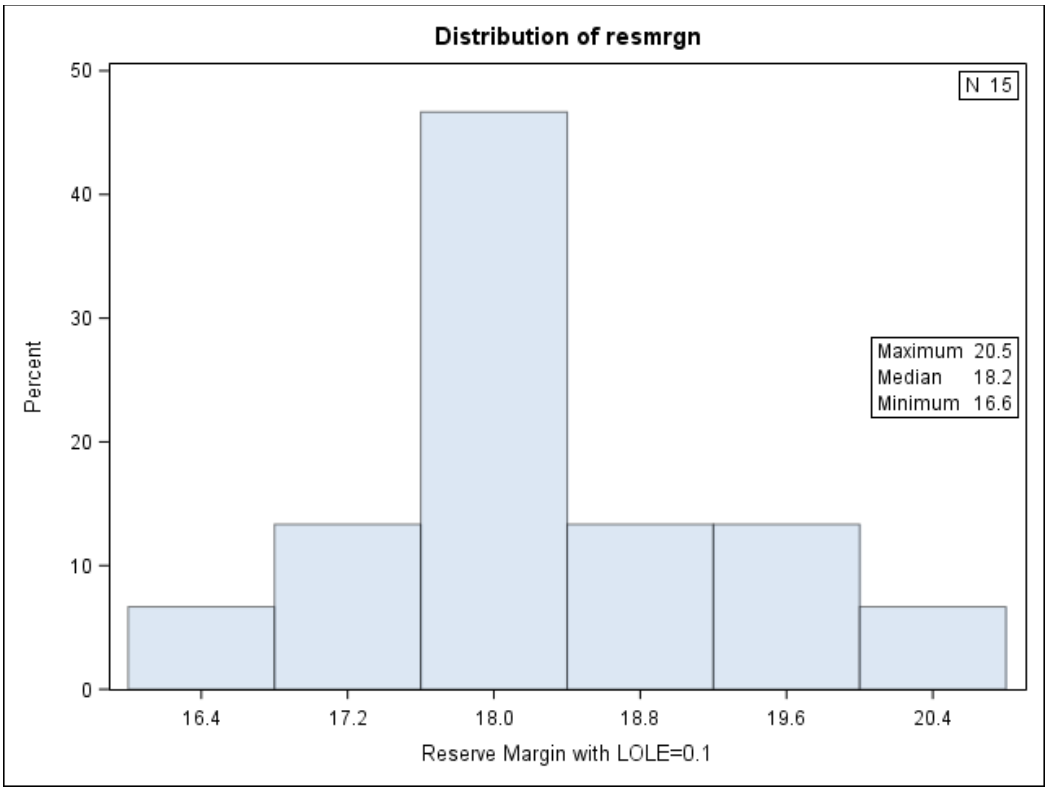
| Variable | DF | Parameter Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|---|
| Intercept | 1 | 8.84337 | 0.03387 | 261.08 | <.0001 |
| lnlole | 1 | -4.00696 | 0.01269 | -315.84 | <.0001 |

The parameter estimates in the function can be used to calculate the reserve margin level associated with an LOLE=0.1. Here are the calculations:

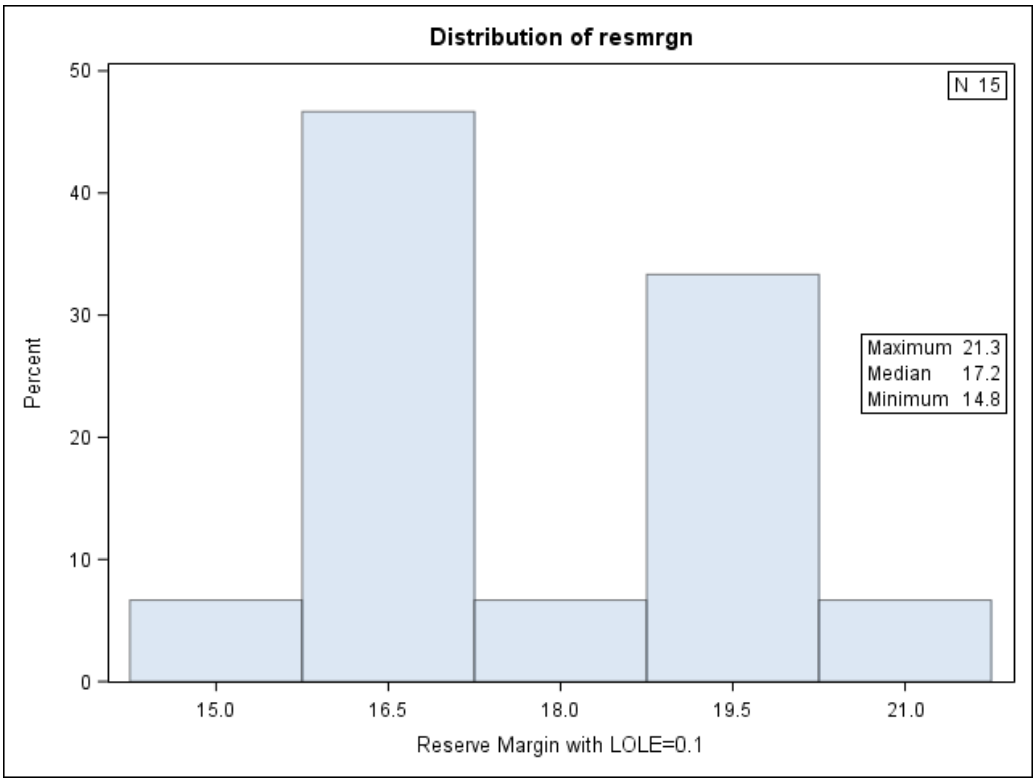
Reserve Margin = a + b * LOG(LOLE)
= 8.84337 – 4.00696 * LOG (0.1)
= 8.84337 – 4.00696 * (-2.30259)
= 18.1

Thus, based on the average LOLE data, an LOLE value of 0.1 requires about an 18.1% reserve margin. The equation can also be used to find the LOLE for a given reserve margin by reversing the solution process. For example, it is easy to show that SCE&G's base winter reserve margin level of 14% is associated with an LOLE=0.3 or again about a 3 day in 10 LOLE level.

The same log-linear function can be estimated for each year in the study under both the peak method of adjustment and the energy method of adjustment. Once the equations are estimated, their parameters can be used to solve for the reserve margin level associated with an LOLE of 0.1 just as demonstrated above. The following histogram shows the distribution of results for the peak method.




The following histogram shows the results under the energy method of adjustment.



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**LOLE and the Risk Analysis of Extreme Peaks**

The LOLE index may be useful as a measure of the average risk on a system over the entire year but it does not address the risk from peak demands that spike up under severe weather conditions. This can be demonstrated through a simple experiment involving three steps. The first step is to run the LOLE analysis for a year and note the LOLE value. In step two add a spike in load on the peak day. Since SCE&G is concerned with a winter spike in load of around 500 MW, this experiment will increase the peak load by 500. Then the LOLE analysis is run again on the modified load data and the LOLE value is noted. It will be higher than step one indicating increased risk over the year. In step 3, the amount of capacity is increased to a level that restores the LOLE value to its original value under step one. This may take a few iterations to home in on the desired LOLE value. The increase in capacity over step one will be the amount required to offset the increase in risk caused by the spike in peak demand according to LOLE theory.

Using the adjusted 2018 load data and a 500 MW spike in peak load, the above experiment was run. The following table summarizes the results.

| **Experiment to Analyze Peak Load Increase and Risk** | | | |
|---|---|---|---|
| | **Peak Load** | **Capacity** | **LOLE** |
| **Step 1: Calculate base value of LOLE** | **4,964** | **5,900** | **0.11235** |
| **Step 2: Add 500 MW to peak day** | **5,464** | **5,900** | **0.23616** |
| **Step 3: Increase Capacity to Restore LOLE** | **5,464** | **6,095** | **0.11234** |

The LOLE results suggest that an increase of 195 MW in capacity (=6,095-5,900) is sufficient to offset the increase in risk caused by a 500 MW spike in load (=5,464-4,964). This does not seem reasonable. However, the LOLE methodology arrives at this conclusion because it is measuring risk for the entire year and the capacity increase of 195 MW makes every day in the year a little less risky so much so that the unacceptable risk on the peak day is completely offset by the sum of these daily increases.

# APPENDIX

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**Table 1 Annual Summary Information for Adjusted Historical Profiles**

**<u>"The Energy Method"</u> Historical Profiles Adjusted to 2019 Energy**

| year | maxmw | summwh |
|---|---|---|
| 2004 | 4,532 | 23,864,178 |
| 2005 | 4,758 | 23,864,178 |
| 2006 | 4,737 | 23,864,178 |
| 2007 | 4,803 | 23,864,178 |
| 2008 | 4,702 | 23,864,178 |
| 2009 | 4,642 | 23,864,178 |
| 2010 | 4,471 | 23,864,178 |
| 2011 | 4,757 | 23,864,178 |
| 2012 | 4,796 | 23,864,178 |
| 2013 | 4,636 | 23,864,178 |
| 2014 | 4,722 | 23,864,178 |
| 2015 | 4,867 | 23,864,178 |
| 2016 | 4,658 | 23,864,178 |
| 2017 | 4,650 | 23,864,178 |
| 2018 | 4,558 | 23,864,178 |

**<u>"The Peak Method"</u> Historical Profiles Adjusted to 2019 Seasonal Peak Demands**

| year | smr_ maxmw | wtr_ maxmw | summwh |
|---|---|---|---|
| 2004 | 4,911 | 4,964 | 27,419,072 |
| 2005 | 4,911 | 4,964 | 25,821,068 |
| 2006 | 4,911 | 4,964 | 26,985,458 |
| 2007 | 4,911 | 4,964 | 26,816,776 |
| 2008 | 4,911 | 4,964 | 25,576,498 |
| 2009 | 4,911 | 4,964 | 25,407,442 |
| 2010 | 4,911 | 4,964 | 26,390,123 |
| 2011 | 4,911 | 4,964 | 24,798,622 |
| 2012 | 4,911 | 4,964 | 25,497,702 |
| 2013 | 4,911 | 4,964 | 27,185,234 |
| 2014 | 4,911 | 4,964 | 25,686,071 |
| 2015 | 4,911 | 4,964 | 24,800,039 |
| 2016 | 4,911 | 4,964 | 26,329,200 |
| 2017 | 4,911 | 4,964 | 25,951,274 |
| 2018 | 4,911 | 4,964 | 25,890,877 |



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**Table 2 Capacity Outage Probability Table ("COPT")**

Note: LOLP represents the cumulative probability. For example, from the table the probability of 100 MW or more being forced out is about 48.32% while for 900 MW, it's 1.35%.

| MW Out | LOLP | MW Out | LOLP | MW Out | LOLP |
|---|---|---|---|---|---|
| 0 | 1.0000 | 530 | 0.0928 | 1600 | 0.0002 |
| 10 | 0.9342 | 540 | 0.0902 | 1700 | 0.0001 |
| 20 | 0.8588 | 550 | 0.0879 | 1800 | 0.0000 |
| 30 | 0.8044 | 560 | 0.0861 | 1900 | 0.0000 |
| 40 | 0.7463 | 570 | 0.0844 | 2000 | 0.0000 |
| 50 | 0.6969 | 580 | 0.0828 | 2100 | 0.0000 |
| 60 | 0.6493 | 590 | 0.0813 | 2200 | 0.0000 |
| 70 | 0.6113 | 600 | 0.0798 | 2300 | 0.0000 |
| 80 | 0.5670 | 610 | 0.0784 | 2400 | 0.0000 |
| 90 | 0.5231 | 620 | 0.0739 | 2500 | 0.0000 |
| 100 | 0.4832 | 630 | 0.0691 | 2600 | 0.0000 |
| 110 | 0.4497 | 640 | 0.0655 | 2700 | 0.0000 |
| 120 | 0.4261 | 650 | 0.0618 | 2800 | 0.0000 |
| 130 | 0.4010 | 660 | 0.0586 | 2900 | 0.0000 |
| 140 | 0.3803 | 670 | 0.0547 | 3000 | 0.0000 |
| 150 | 0.3620 | 680 | 0.0510 | 3100 | 0.0000 |
| 160 | 0.3483 | 690 | 0.0472 | 3200 | 0.0000 |
| 170 | 0.3358 | 700 | 0.0436 | 3300 | 0.0000 |
| 180 | 0.3199 | 710 | 0.0404 | 3400 | 0.0000 |
| 190 | 0.3072 | 720 | 0.0375 | 3500 | 0.0000 |
| 200 | 0.2946 | 730 | 0.0352 | 3600 | 0.0000 |
| 210 | 0.2841 | 740 | 0.0329 | 3700 | 0.0000 |
| 220 | 0.2744 | 750 | 0.0308 | 3800 | 0.0000 |
| 230 | 0.2663 | 760 | 0.0287 | 3900 | 0.0000 |
| 240 | 0.2587 | 770 | 0.0270 | 4000 | 0.0000 |
| 250 | 0.2509 | 780 | 0.0253 | 4100 | 0.0000 |
| 260 | 0.2432 | 790 | 0.0237 | 4200 | 0.0000 |
| 270 | 0.2362 | 800 | 0.0223 | 4300 | 0.0000 |
| 280 | 0.2309 | 810 | 0.0210 | 4400 | 0.0000 |
| 290 | 0.2262 | 820 | 0.0199 | 4500 | 0.0000 |
| 300 | 0.2220 | 830 | 0.0189 | 4600 | 0.0000 |
| 310 | 0.2182 | 840 | 0.0178 | 4700 | 0.0000 |
| 320 | 0.2151 | 850 | 0.0169 | 4800 | 0.0000 |
| 330 | 0.2124 | 860 | 0.0161 | 4900 | 0.0000 |
| 340 | 0.2099 | 870 | 0.0153 | 5000 | 0.0000 |
| 350 | 0.2017 | 880 | 0.0146 | 5100 | 0.0000 |
| 360 | 0.1927 | 890 | 0.0140 | 5200 | 0.0000 |
| 370 | 0.1842 | 900 | 0.0135 | 5300 | 0.0000 |
| 380 | 0.1761 | 910 | 0.0130 | 5400 | 0.0000 |
| 390 | 0.1705 | 920 | 0.0126 | 5500 | 0.0000 |
| 400 | 0.1643 | 930 | 0.0122 | 5600 | 0.0000 |
| 410 | 0.1573 | 940 | 0.0119 | 5700 | 0.0000 |
| 420 | 0.1483 | 950 | 0.0116 | 5800 | 0.0000 |
| 430 | 0.1413 | 960 | 0.0110 | 5900 | 0.0000 |
| 440 | 0.1330 | 970 | 0.0104 | | |
| 450 | 0.1260 | 980 | 0.0099 | | |
| 460 | 0.1202 | 990 | 0.0094 | | |
| 470 | 0.1149 | 1000 | 0.0090 | | |
| 480 | 0.1105 | 1100 | 0.0042 | | |
| 490 | 0.1061 | 1200 | 0.0022 | | |
| 500 | 0.1023 | 1300 | 0.0013 | | |
| 510 | 0.0990 | 1400 | 0.0006 | | |
| 520 | 0.0958 | 1500 | 0.0003 | | |



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**Table 3 LOLE Index by Reserve Margin Based on the "Peak Method" of Adjustment**

| resmrg | _2004 | _2005 | _2006 | _2007 | _2008 | _2009 | _2010 | _2011 |
|---|---|---|---|---|---|---|---|---|
| 12.0 | 0.43304 | 0.33493 | 0.62506 | 0.49446 | 0.35865 | 0.48997 | 0.83839 | 0.45379 |
| 12.5 | 0.38234 | 0.28952 | 0.54329 | 0.43004 | 0.31434 | 0.42833 | 0.73506 | 0.39627 |
| 13.0 | 0.33579 | 0.24906 | 0.47080 | 0.37403 | 0.27465 | 0.37130 | 0.64482 | 0.34655 |
| 13.5 | 0.29427 | 0.21524 | 0.40965 | 0.32541 | 0.23864 | 0.32148 | 0.56614 | 0.30450 |
| 14.0 | 0.25945 | 0.18814 | 0.35898 | 0.28510 | 0.20909 | 0.28084 | 0.49862 | 0.27099 |
| 14.5 | 0.22773 | 0.16403 | 0.31291 | 0.24937 | 0.18232 | 0.24306 | 0.43714 | 0.24048 |
| 15.0 | 0.19996 | 0.14384 | 0.27486 | 0.21966 | 0.15906 | 0.21196 | 0.38459 | 0.21339 |
| 15.5 | 0.17568 | 0.12679 | 0.24355 | 0.19491 | 0.13993 | 0.18567 | 0.33983 | 0.19098 |
| 16.0 | 0.15441 | 0.11227 | 0.21634 | 0.17372 | 0.12290 | 0.16291 | 0.30107 | 0.17029 |
| 16.5 | 0.13568 | 0.09938 | 0.19270 | 0.15497 | 0.10799 | 0.14351 | 0.26625 | 0.15038 |
| 17.0 | 0.11934 | 0.08851 | 0.17207 | 0.13810 | 0.09560 | 0.12756 | 0.23707 | 0.13313 |
| 17.5 | 0.10555 | 0.07983 | 0.15480 | 0.12416 | 0.08519 | 0.11502 | 0.21279 | 0.11820 |
| 18.0 | 0.09296 | 0.07167 | 0.13861 | 0.11035 | 0.07558 | 0.10297 | 0.18781 | 0.10352 |
| 18.5 | 0.08209 | 0.06410 | 0.12357 | 0.09739 | 0.06721 | 0.09244 | 0.16592 | 0.09087 |
| 19.0 | 0.07391 | 0.05802 | 0.11111 | 0.08749 | 0.06078 | 0.08396 | 0.14894 | 0.08126 |
| 19.5 | 0.06554 | 0.05169 | 0.09799 | 0.07714 | 0.05409 | 0.07458 | 0.13103 | 0.07128 |
| 20.0 | 0.05784 | 0.04539 | 0.08579 | 0.06728 | 0.04766 | 0.06578 | 0.11438 | 0.06211 |
| 20.5 | 0.05115 | 0.03956 | 0.07476 | 0.05872 | 0.04194 | 0.05798 | 0.10023 | 0.05441 |
| 21.0 | 0.04541 | 0.03469 | 0.06558 | 0.05162 | 0.03704 | 0.05088 | 0.08837 | 0.04816 |
| 21.5 | 0.03935 | 0.02986 | 0.05648 | 0.04460 | 0.03197 | 0.04389 | 0.07692 | 0.04207 |
| 22.0 | 0.03466 | 0.02608 | 0.04945 | 0.03922 | 0.02806 | 0.03839 | 0.06781 | 0.03737 |
| 22.5 | 0.03064 | 0.02290 | 0.04340 | 0.03455 | 0.02467 | 0.03348 | 0.05980 | 0.03310 |
| 23.0 | 0.02702 | 0.01995 | 0.03807 | 0.03043 | 0.02158 | 0.02921 | 0.05265 | 0.02921 |
| 23.5 | 0.02368 | 0.01740 | 0.03347 | 0.02683 | 0.01882 | 0.02549 | 0.04628 | 0.02578 |
| 24.0 | 0.02087 | 0.01544 | 0.02987 | 0.02391 | 0.01663 | 0.02254 | 0.04115 | 0.02305 |
| 24.5 | 0.01836 | 0.01370 | 0.02664 | 0.02125 | 0.01467 | 0.01990 | 0.03648 | 0.02043 |
| 25.0 | 0.01628 | 0.01223 | 0.02381 | 0.01889 | 0.01304 | 0.01769 | 0.03249 | 0.01814 |
| 25.5 | 0.01452 | 0.01099 | 0.02140 | 0.01688 | 0.01164 | 0.01590 | 0.02902 | 0.01617 |

| resmrg | _2012 | _2013 | _2014 | _2015 | _2016 | _2017 | _2018 |
|---|---|---|---|---|---|---|---|
| 12.0 | 0.34195 | 0.47973 | 0.50334 | 0.68108 | 0.59148 | 0.47691 | 0.60222 |
| 12.5 | 0.29966 | 0.41645 | 0.44353 | 0.59311 | 0.51914 | 0.41560 | 0.52399 |
| 13.0 | 0.26082 | 0.36145 | 0.38897 | 0.51658 | 0.45567 | 0.36194 | 0.45509 |
| 13.5 | 0.22690 | 0.31301 | 0.33929 | 0.45024 | 0.40182 | 0.31619 | 0.39603 |
| 14.0 | 0.19992 | 0.27391 | 0.29755 | 0.39668 | 0.35717 | 0.27895 | 0.34868 |
| 14.5 | 0.17554 | 0.23941 | 0.25920 | 0.34994 | 0.31687 | 0.24577 | 0.30656 |
| 15.0 | 0.15492 | 0.21057 | 0.22644 | 0.30979 | 0.28188 | 0.21875 | 0.27134 |
| 15.5 | 0.13721 | 0.18673 | 0.19922 | 0.27610 | 0.25044 | 0.19479 | 0.24061 |
| 16.0 | 0.12178 | 0.16605 | 0.17604 | 0.24680 | 0.22174 | 0.17309 | 0.21397 |
| 16.5 | 0.10773 | 0.14804 | 0.15529 | 0.22118 | 0.19539 | 0.15444 | 0.19091 |
| 17.0 | 0.09539 | 0.13315 | 0.13729 | 0.19884 | 0.17194 | 0.13755 | 0.17067 |
| 17.5 | 0.08499 | 0.12083 | 0.12224 | 0.17871 | 0.15189 | 0.12279 | 0.15283 |
| 18.0 | 0.07510 | 0.10732 | 0.10825 | 0.15769 | 0.13273 | 0.10798 | 0.13558 |
| 18.5 | 0.06636 | 0.09521 | 0.09596 | 0.13974 | 0.11612 | 0.09488 | 0.11990 |
| 19.0 | 0.05970 | 0.08596 | 0.08641 | 0.12508 | 0.10348 | 0.08500 | 0.10756 |
| 19.5 | 0.05282 | 0.07554 | 0.07654 | 0.10919 | 0.09103 | 0.07486 | 0.09461 |
| 20.0 | 0.04635 | 0.06568 | 0.06726 | 0.09460 | 0.07975 | 0.06513 | 0.08234 |
| 20.5 | 0.04084 | 0.05736 | 0.05926 | 0.08252 | 0.07026 | 0.05697 | 0.07183 |
| 21.0 | 0.03604 | 0.05022 | 0.05239 | 0.07242 | 0.06244 | 0.05020 | 0.06297 |
| 21.5 | 0.03114 | 0.04315 | 0.04539 | 0.06268 | 0.05464 | 0.04343 | 0.05441 |
| 22.0 | 0.02742 | 0.03774 | 0.03978 | 0.05523 | 0.04853 | 0.03821 | 0.04792 |
| 22.5 | 0.02429 | 0.03320 | 0.03498 | 0.04891 | 0.04311 | 0.03378 | 0.04234 |
| 23.0 | 0.02141 | 0.02927 | 0.03073 | 0.04334 | 0.03819 | 0.02991 | 0.03734 |
| 23.5 | 0.01875 | 0.02582 | 0.02694 | 0.03824 | 0.03359 | 0.02647 | 0.03281 |
| 24.0 | 0.01662 | 0.02293 | 0.02385 | 0.03406 | 0.02979 | 0.02358 | 0.02920 |
| 24.5 | 0.01465 | 0.02039 | 0.02107 | 0.03040 | 0.02631 | 0.02086 | 0.02603 |
| 25.0 | 0.01301 | 0.01830 | 0.01868 | 0.02729 | 0.02330 | 0.01862 | 0.02338 |
| 25.5 | 0.01162 | 0.01656 | 0.01668 | 0.02454 | 0.02071 | 0.01674 | 0.02094 |



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**Table 4 LOLE Index by Reserve Margin Based on the "Energy Method" of Adjustment**

| resmrg | _2004 | _2005 | _2006 | _2007 | _2008 | _2009 | _2010 | _2011 |
|---|---|---|---|---|---|---|---|---|
| 12.0 | 0.29226 | 0.27686 | 0.46937 | 0.37424 | 0.37084 | 0.57333 | 1.04027 | 0.59745 |
| 12.5 | 0.25781 | 0.24348 | 0.40882 | 0.32623 | 0.32538 | 0.50346 | 0.91209 | 0.52065 |
| 13.0 | 0.22587 | 0.21116 | 0.35660 | 0.28759 | 0.28646 | 0.44189 | 0.79405 | 0.44877 |
| 13.5 | 0.19849 | 0.18237 | 0.30852 | 0.25069 | 0.25061 | 0.38121 | 0.69132 | 0.38656 |
| 14.0 | 0.17449 | 0.15778 | 0.26912 | 0.21984 | 0.22108 | 0.33125 | 0.60640 | 0.34001 |
| 14.5 | 0.15279 | 0.13840 | 0.23629 | 0.19330 | 0.19472 | 0.28873 | 0.53515 | 0.30082 |
| 15.0 | 0.13478 | 0.12105 | 0.20799 | 0.17042 | 0.17105 | 0.25093 | 0.47095 | 0.26634 |
| 15.5 | 0.11819 | 0.10705 | 0.18208 | 0.14913 | 0.15117 | 0.21842 | 0.41459 | 0.23882 |
| 16.0 | 0.10349 | 0.09510 | 0.16150 | 0.13151 | 0.13256 | 0.19121 | 0.36917 | 0.21311 |
| 16.5 | 0.09128 | 0.08465 | 0.14290 | 0.11640 | 0.11685 | 0.16736 | 0.32648 | 0.19115 |
| 17.0 | 0.08036 | 0.07508 | 0.12686 | 0.10361 | 0.10242 | 0.14794 | 0.29007 | 0.17233 |
| 17.5 | 0.07035 | 0.06714 | 0.11360 | 0.09235 | 0.09040 | 0.13154 | 0.25950 | 0.15329 |
| 18.0 | 0.06245 | 0.05917 | 0.10174 | 0.08258 | 0.07997 | 0.11813 | 0.23035 | 0.13646 |
| 18.5 | 0.05527 | 0.05246 | 0.09068 | 0.07359 | 0.07076 | 0.10696 | 0.20583 | 0.12126 |
| 19.0 | 0.04902 | 0.04715 | 0.08089 | 0.06592 | 0.06284 | 0.09665 | 0.18357 | 0.10816 |
| 19.5 | 0.04339 | 0.04144 | 0.07225 | 0.05866 | 0.05519 | 0.08642 | 0.16144 | 0.09409 |
| 20.0 | 0.03858 | 0.03645 | 0.06346 | 0.05129 | 0.04901 | 0.07700 | 0.14256 | 0.08244 |
| 20.5 | 0.03399 | 0.03215 | 0.05575 | 0.04520 | 0.04322 | 0.06871 | 0.12592 | 0.07209 |
| 21.0 | 0.03004 | 0.02826 | 0.04905 | 0.03952 | 0.03826 | 0.05976 | 0.11022 | 0.06279 |
| 21.5 | 0.02662 | 0.02449 | 0.04266 | 0.03464 | 0.03365 | 0.05210 | 0.09588 | 0.05458 |
| 22.0 | 0.02324 | 0.02142 | 0.03701 | 0.03016 | 0.02963 | 0.04553 | 0.08401 | 0.04785 |
| 22.5 | 0.02037 | 0.01871 | 0.03249 | 0.02647 | 0.02593 | 0.03948 | 0.07385 | 0.04192 |
| 23.0 | 0.01807 | 0.01646 | 0.02840 | 0.02352 | 0.02276 | 0.03440 | 0.06504 | 0.03717 |
| 23.5 | 0.01593 | 0.01448 | 0.02498 | 0.02071 | 0.02010 | 0.03014 | 0.05751 | 0.03311 |
| 24.0 | 0.01393 | 0.01314 | 0.02214 | 0.01825 | 0.01774 | 0.02646 | 0.05108 | 0.02906 |
| 24.5 | 0.01234 | 0.01144 | 0.01940 | 0.01616 | 0.01562 | 0.02324 | 0.04516 | 0.02647 |
| 25.0 | 0.01089 | 0.01009 | 0.01765 | 0.01450 | 0.01378 | 0.02067 | 0.04013 | 0.02360 |
| 25.5 | 0.00965 | 0.00897 | 0.01565 | 0.01293 | 0.01248 | 0.01832 | 0.03577 | 0.02114 |

| resmrg | _2012 | _2013 | _2014 | _2015 | _2016 | _2017 | _2018 |
|---|---|---|---|---|---|---|---|
| 12.0 | 0.36312 | 0.27772 | 0.21390 | 0.31315 | 0.61847 | 0.55622 | 0.67135 |
| 12.5 | 0.31640 | 0.24410 | 0.18773 | 0.27953 | 0.53751 | 0.48258 | 0.58840 |
| 13.0 | 0.27804 | 0.21059 | 0.16401 | 0.24748 | 0.47098 | 0.42163 | 0.50893 |
| 13.5 | 0.24092 | 0.18198 | 0.14117 | 0.21822 | 0.41044 | 0.36520 | 0.44279 |
| 14.0 | 0.21091 | 0.15843 | 0.12199 | 0.19151 | 0.36065 | 0.32005 | 0.39064 |
| 14.5 | 0.18544 | 0.13714 | 0.10532 | 0.16994 | 0.32024 | 0.28051 | 0.34284 |
| 15.0 | 0.16342 | 0.12047 | 0.09156 | 0.14794 | 0.28384 | 0.24857 | 0.30292 |
| 15.5 | 0.14489 | 0.10550 | 0.07972 | 0.12813 | 0.25354 | 0.22082 | 0.27042 |
| 16.0 | 0.12929 | 0.09362 | 0.06970 | 0.11102 | 0.22724 | 0.19688 | 0.24002 |
| 16.5 | 0.11518 | 0.08392 | 0.06092 | 0.09710 | 0.20343 | 0.17686 | 0.21370 |
| 17.0 | 0.10310 | 0.07538 | 0.05395 | 0.08428 | 0.18037 | 0.15723 | 0.19195 |
| 17.5 | 0.09167 | 0.06724 | 0.04780 | 0.07384 | 0.15995 | 0.14018 | 0.17022 |
| 18.0 | 0.08209 | 0.06016 | 0.04280 | 0.06534 | 0.14167 | 0.12551 | 0.15198 |
| 18.5 | 0.07224 | 0.05382 | 0.03849 | 0.05840 | 0.12386 | 0.11142 | 0.13484 |
| 19.0 | 0.06387 | 0.04805 | 0.03461 | 0.05205 | 0.10964 | 0.09894 | 0.11951 |
| 19.5 | 0.05628 | 0.04225 | 0.03114 | 0.04652 | 0.09580 | 0.08692 | 0.10528 |
| 20.0 | 0.04945 | 0.03739 | 0.02756 | 0.04124 | 0.08369 | 0.07635 | 0.09206 |
| 20.5 | 0.04316 | 0.03257 | 0.02445 | 0.03680 | 0.07310 | 0.06677 | 0.08070 |
| 21.0 | 0.03787 | 0.02853 | 0.02150 | 0.03268 | 0.06404 | 0.05850 | 0.07032 |
| 21.5 | 0.03308 | 0.02473 | 0.01866 | 0.02917 | 0.05663 | 0.05072 | 0.06119 |
| 22.0 | 0.02897 | 0.02153 | 0.01621 | 0.02557 | 0.04960 | 0.04460 | 0.05369 |
| 22.5 | 0.02546 | 0.01899 | 0.01421 | 0.02226 | 0.04372 | 0.03902 | 0.04747 |
| 23.0 | 0.02213 | 0.01649 | 0.01227 | 0.01959 | 0.03904 | 0.03424 | 0.04180 |
| 23.5 | 0.02008 | 0.01446 | 0.01076 | 0.01718 | 0.03463 | 0.03031 | 0.03691 |
| 24.0 | 0.01780 | 0.01289 | 0.00937 | 0.01493 | 0.03094 | 0.02702 | 0.03276 |
| 24.5 | 0.01582 | 0.01148 | 0.00824 | 0.01309 | 0.02746 | 0.02403 | 0.02916 |
| 25.0 | 0.01404 | 0.01026 | 0.00749 | 0.01153 | 0.02441 | 0.02147 | 0.02624 |
| 25.5 | 0.01246 | 0.00907 | 0.00652 | 0.01022 | 0.02153 | 0.01922 | 0.02323 |



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