BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
DRAFT LOCAL CAPACITY TECHNICAL ANALYSIS AND FLEXIBLE CAPACITY NEEDS ASSESSMENT FOR 2019

The California Independent System Operator Corporation (CAISO) hereby provides its Draft Flexible Capacity Needs Assessment and Local Capacity Technical Analysis for 2018. The CAISO is providing the draft studies as requested in the March 27, 2018 Assigned Commission and Administrative Law Judge's Joint Ruling Modifying the Track 1 Schedule (Ruling). Because these are draft studies, the final results are subject to change based on feedback received in the CAISO's stakeholder processes or the CAISO's own internal review. The CAISO will provide final studies by May 15, as outlined in the Ruling.

The Draft Flexible Capacity Needs Assessment is included as Attachment A to this filing and can be accessed at: http://www.caiso.com/Documents/2019DraftFlexibleCapacityNeedsAssessment.pdf.

The Draft Local Capacity Technical Analysis is included as Attachment B to this filing and can be accessed at: http://www.caiso.com/Documents/Draft2019LocalCapacityTechnicalReport.pdf.

Respectfully submitted,

By: *<u>/s/ Jordan Pinjuv</u>*
Roger E. Collanton
General Counsel
Anthony Ivancovich
Deputy General Counsel
Jordan Pinjuv
Senior Counsel
California Independent System

Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 351-4429
Fax: (916) 608-7222
jpinjuv@caiso.com

Attorneys for the California Independent
System Operator Corporation

Dated: April 23, 2018

Attachment A

Draft Flexible Capacity Needs Assessment

California Independent System Operator Corporation

Draft Flexible Capacity Needs Assessment for 2019

April 13, 2018

Table of Contents

1. Introduction

The ISO conducts an annual flexible capacity technical study to determine the flexible capacity needed to help ensure the ISO system reliability is maintained as specified in the ISO Tariff section 40.10.1. The ISO developed the study process in the ISO's Flexible Resource Adequacy Criteria and Must-Offer Obligation ("FRAC-MOO") stakeholder initiative and in conjunction with the CPUC annual Resource Adequacy proceeding (R.11-10-023). This report presents the ISO's draft flexible capacity needs assessment specifying the ISO's forecast monthly flexible capacity needs in 2019.

The ISO calculates the overall flexible capacity need of the ISO system and the relative contributions to this need attributable to the load serving entities (LSEs) under each local regulatory authority (LRA). This report details the system-level flexible capacity needs and the aggregate flexible capacity need attributable to CPUC jurisdictional load serving entities (LSEs). This report does not break-out the flexible capacity need attributable to individual local regulatory authorities (LRAs) other than the CPUC.

The ISO will use the results from the final study to allocate shares of the system flexible capacity[1] need to each LRA with LSEs responsible for load in the ISO balancing authority area consistent with the allocation methodology set forth in the ISO's tariff section 40.10.2. Based on that allocation, the ISO will advise each LRA of its MW share of the ISO's flexible capacity need.

2. Summary

The ISO determines the quantity of flexible capacity needed each month to reliably address its flexibility and ramping needs for the upcoming resource adequacy year and publishes its findings in this flexible capacity needs assessment. The ISO calculates flexible capacity needs using the calculation method developed in the FRAC-MOO stakeholder initiative and codified in the ISO Tariff. This methodology includes calculating the seasonal amounts of three flexible capacity categories and determining seasonal must-offer obligations for two of these flexible capacity categories.

The key results of the ISO's flexible capacity needs assessment for 2019 are based on the following dataset provide by the California Energy Commission for 2019:

1. Hourly "1 in 2" weather pattern mid load profiles,
2. Hourly mid additional achievable energy efficiency (AAEE) profiles, and
3. Hourly mid solar PV production

1) System-wide flexible capacity needs for 2019 are greatest in the non-summer months and range from 11,631 MW in July to 18,014 MW in December.

2) The minimum amount of flexible capacity needed from the “base flexibility” category is 59 percent of the total amount of installed or available flexible capacity in the summer months (May – September) and 45 percent of the total amount of flexible capacity for the non-summer months (October – April).

3) The ISO will establish the time period of the must-offer obligation for resources counted in the “Peak” and “Super-Peak” flexible capacity categories as the five-hour periods of HE 14 through HE 19 for January through April and October through December; HE 15 through HE 20 for May through September. These hours are the same from those in Final Flexible Capacity Needs Assessment for 2018.

4) In previous years, the ISO has published advisory requirements the two years following the upcoming Resource Adequacy (RA) year. At the time of this publication, the ISO is processing results for 2020 and 2021. Once this data is processed, the ISO will issue advisory results for those years.

3. Defining the ISO System-Wide Flexible Capacity Need

Based on the methodology described in the ISO's Tariff and the business practice manual,[2] the ISO calculated the ISO system-wide flexible capacity needs as follows:

$$Flexibility\ Need_{MTH_y} = Max\left[\left(3RR_{HR_x}\right)_{MTH_y}\right] + Max\left(MSSC, 3.5\% * E\left(PL_{MTH_y}\right)\right) + \varepsilon$$

Where:

$Max[(3RR_{HRx})_{MTHy}]$ = Largest three hour contiguous ramp starting in hour x for month y
E(PL) = Expected peak load
MTHy = Month y
MSSC = Most Severe Single Contingency

ε = Annually adjustable error term to account for load forecast errors and variability methodology

For the 2019 RA compliance year, the ISO will continue to set ε equal to zero.

[2] Reliability Requirements business practice manual Section 10. Available at http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements

In order to determine the flexible capacity needs, including the quantities needed in each of the defined flexible capacity categories, the ISO conducted a six-step assessment process:

1) Forecast minute-by-minute net load using all expected and existing wind and solar resources and the most recent year of actual load, as adjusted for load growth;

2) Calculate the monthly system-level 3-hour net load ramp needs using forecast minute-to-minute net load forecast;

3) Calculate the percentages needed in each category in each month and add the contingency requirements into the categories proportionally to the percentages established calculated in step 2;

4) Analyze the distributions of both largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations;

5) Calculate a simple average of the percent of base flexibility needs for all months within a season; and

6) Determine each LRA's contribution to the flexible capacity need.

This methodology allows the ISO to make enhancements and assumptions based on its experience and any updated or new information that becomes available.

4. Forecasting Minute-by-Minute Net load

The first step in developing the flexible capacity needs assessment was to forecast the net load. To produce this forecast, the ISO collected the requisite information regarding the expected build-out of the fleet of variable energy resources. After obtaining this data from all LSEs, the ISO constructed the forecast minute-by-minute load, wind, grid connected solar and behind-the-meter rooftop solar PV profiles before calculating the net load curves for 2018 through 2021.

4.1 Building the Forecasted Variable Energy Resource Portfolio

To collect the necessary data, the ISO sent a data request in December, 2017 to the scheduling coordinators for all LSEs representing load in the ISO balancing area.[3] The deadline for submitting the data was January 15, 2018. At the time of this report, the ISO has received data from all LSEs. The data request asked for information on each wind, solar, and distributed wind and solar resource that the LSE owns, in whole or in part, or is under contractual commitment to the LSE for all or a portion of its capacity. As part of the data request, the ISO

[3] A reminder notice was also sent out on January, 2018.

asked for information on resources internal and external to the ISO. For resources that are external to the ISO, the ISO requested additional information as to whether the resource is or will be dynamically scheduled into the ISO. The ISO only included external resources in the flexible capacity requirements assessment if they were dynamically scheduled to the ISO. Based on ISO review of the responses to the data request, it appears that the information submitted represents all wind, solar, and distributed wind and solar resources that the LSE owns, in whole or in part, or is contractual committed to the LSE for all or a portion of its capacity within the ISO balancing area.

Using the LSEs' data, the ISO simulated the variable energy resources' output to produce forecast minute-by-minute net load curves[4] for 2019. The forecasted aggregated variable energy resource fleet capacity is provided in Table 1.

Table 1: Total ISO System Variable Energy Resource Capacity (Net Dependable Capacity-MW)[5]

Resource Type	Existing MW (2017)	2018 MW	2019 MW
ISO Solar PV	8,262	9,018	10,095
ISO Solar Thermal	1,433	1,178	1,108
ISO Wind	4,611	4,932	4,761
Incremental behind-the-meter Solar PV		1,100	1,194
Total Variable Energy Resource Capacity in the 2017 Flexible Capacity Needs Assessment[6]	14,306	16,228	17,158
Non ISO Resources All external VERS not-firmed by external BAA	1,271	1,197	1,201
Total internal and non-firmed external VERs	15,577	17,425	18,359
Incremental New Additions in Each Year		1,848	934

Table 1 aggregates the variable energy resources system wide, while the behind-the-meter solar PV were modeled as five separate aggregation dispersed throughout the ISO's balancing area. This ensured that the assessment captured the geographic diversity benefits. Additionally, for existing solar and wind resources, the ISO used the most recent full year of actual solar output data available, which was 2017. For future wind resources, the ISO scaled overall wind production for each minute of the most recent year by the expected future capacity divided by the installed wind capacity of the most recent year. Specifically, to develop the wind profiles for wind resources, the ISO used the following formula:

---

4 Net-load load is defined as load minus wind production minus solar production minus behind-the-meter solar PV production.

5 Data shown is for December of the corresponding year. The ISO aggregated variable energy resources across the ISO system to avoid concerns regarding the release of confidential information.

6 Includes all internal variable energy resources

$$2019\ W_{Mth\_Sim\_1\text{-}min} = 2017W_{Act\_1\text{-}min} * 2019W_{Mth\ Capacity} / 2017W_{Mth\ Capacity}$$

To develop 1-minute solar profiles for 2019, the ISO used the actual 1-minute profiles for 2017 using the following formula:

$$2019S_{Mth\_Sim\_1\text{-}min} = 2017S_{Act\_1\text{-}min} * 2019S_{Mth\ Capacity} / 2017S_{Mth\ Capacity}$$

Given the amount of incremental wind and solar resources coming on line, this approach allows the ISO to maintain the load/wind/solar correlation for the forecasted wind and solar capacity outputs.

The ISO's assumptions for solar resources' production portfolios for future years were primarily based on the overall capacity of the new resources.

The ISO obtained hourly behind-the-meter solar PV production data from the CEC, which was used to generate 1-minute of behind-the-meter solar profiles. If this hourly solar PV production data is not factored into the model, it would lead to an undercounting of the net load ramps for future years. Therefore, the ISO has created an additional element to account for the incremental behind the meter solar PV resources in the calculation of the monthly three hour net load ramps. Including this incremental capacity allows the ISO to more accurately capture the forecasted monthly three hour net load ramps. Because behind-the-meter resources are solar PV, the ISO included the contribution of the incremental behind-the-meter solar PV as a subset of the Δ Solar PV, but provides a breakout of the contribution for purposes of determining an LRA's allocable share of the flexible capacity needs.

4.2 Building Minute-by-Minute Net Load Curves

The ISO used the CEC 2017 Integrated Energy Policy Report (IEPR) 1-in-2 monthly peak load forecast (Mid Demand Scenario, with mid-additional achievable energy efficiency) to develop minute-by-minute load forecasts for each month.[7] The ISO scaled the actual load for each minute of each hour of 2017 using an expected load growth factor of the hourly average forecast for 2019 provided by the CEC divided by the actual 2017 hourly average production. In the 2018 flexible capacity studies, the ISO used a different approach because the CEC provided monthly peak forecast so monthly ratios were developed in 2018 instead of hourly ratios developed for the 2019 studies.

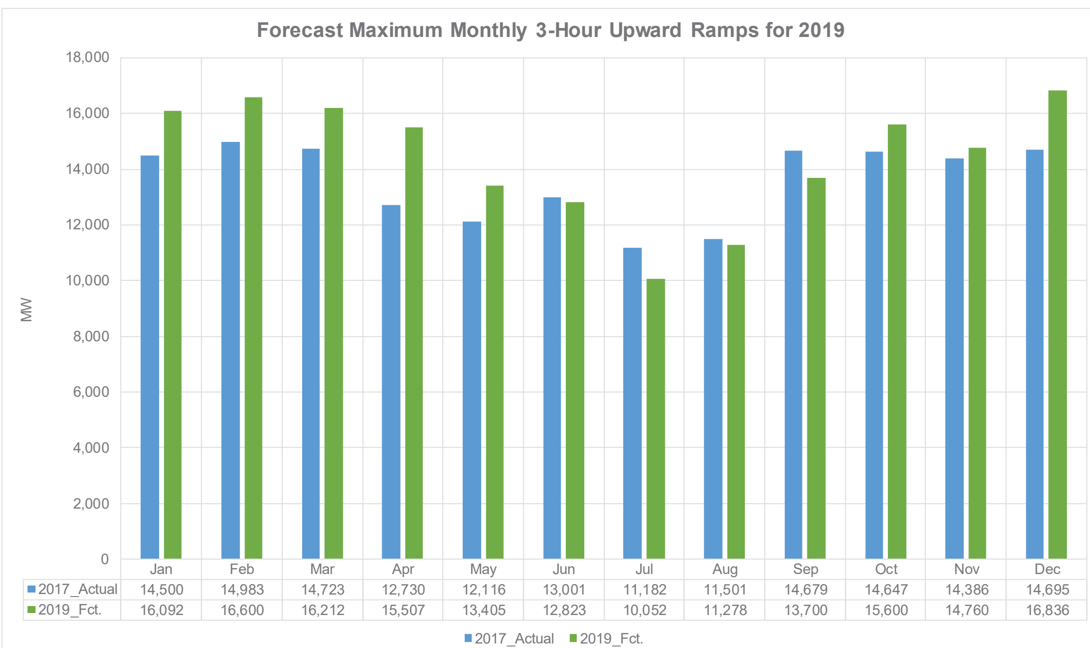
[7] http://www.energy.ca.gov/2014publications/CEC-200-2014-009/CEC-200-2014-009-SD.pdf

Using this forecasted load and expected wind and solar expansions, the ISO developed the minute-by-minute load, wind, and solar profiles. The ISO aligned these profiles and subtracted the output of the wind, solar and behind-the-meter production from the load to generate the minute-by-minute net load curves, which is necessary to conduct the flexible capacity needs assessment.

5. Calculating the Monthly Maximum Three-Hour Net load Ramps Plus 3.5 Percent Expected Peak-Load

The ISO, using the net load forecast developed in Section 4, calculated the maximum three-hour net load ramp for each month of 2019. Figure 1 shows the ISO system-wide largest three-hour net load ramp for each month of 2019 compared with each month of the actual three-hour net load ramp for 2017.

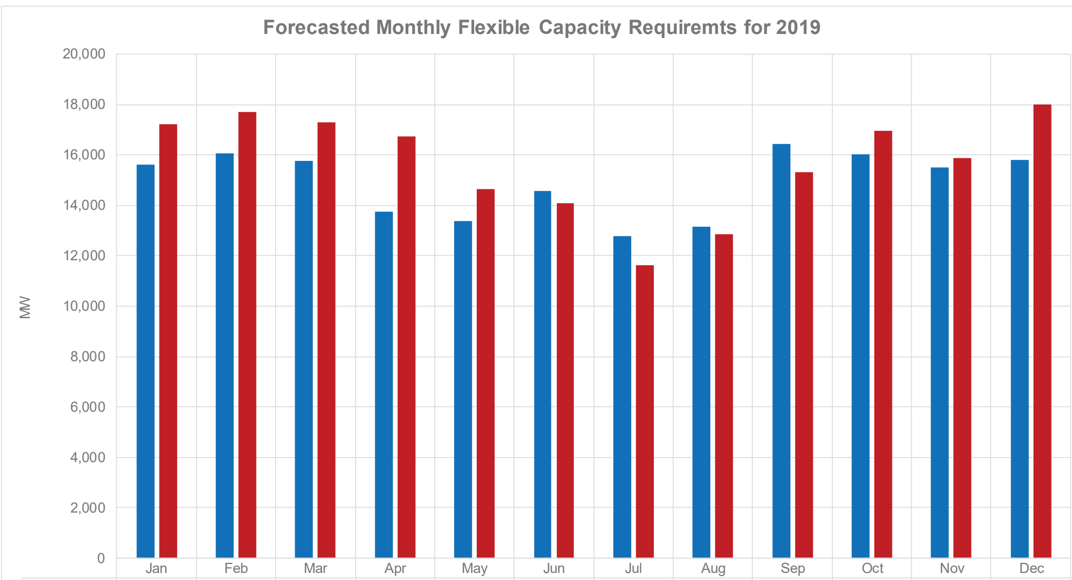
Figure 1: ISO System Maximum 3-hour Net load Ramps



The results for the non-summer months of 2019 are higher than those predicted in the summer months. This is consistent with historical trends. Further, although the three hour net load ramps are forecasted to increase in each of the non-summer month, the differential between the summer maximums and the non-summer maximums was approximately 6,700 MW difference between July and December.

As part of the 2019 Flexible Capacity Needs Assessment, the ISO assessed the weather patterns to identify anomalous results. As shown in Figure 1, flexible capacity needs follow a predictable pattern, whereby the flexible capacity needs for all summer months remain low relative to the flexible capacity needs for non-summer months. Finally, the ISO summed the monthly largest three-hour contiguous ramps and 3.5 percent of the forecast peak-load for each month.[8] This sum yields the ISO system-wide flexible capacity needs for 2019. The monthly flexible capacity needs for 2019 together with the actual monthly flexible capacity needed for 2017 are shown in Figure 2 below.

Figure 2: The ISO System Maximum 3-Hour Net load Ramps Plus 3.5 Percent of Forecast Peak Load



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017_Actual	15,599	16,049	15,766	13,760	13,383	14,551	12,772	13,166	16,433	16,027	15,486	15,782
2019_Fct.	17,226	17,708	17,301	16,741	14,654	14,086	11,631	12,857	15,297	16,972	15,886	18,014

6. Calculating the Seasonal Percentages Needed in Each Category

As described in the ISO Tariff sections 40.10.3.2 and 40.10.3.3, the ISO divided its flexible capacity needs into various categories based on the system's operational needs. These categories are based on the characteristics of the system's net load ramps and define the mix of resources that can be used to meet the system's flexible capacity needs. Certain use-limited resources may not qualify to be counted under the base flexibility category and may only be

[8] The most severe single contingency was consistently less than 3.5 expected peak-load.

counted under the peak flexibility or super-peak flexibility categories, depending on their characteristics. Although there is no limit to the amount of flexible capacity that can come from resources meeting the base flexibility criteria, there is maximum amount of flexible capacity that can come from resources that only meet the criteria to be counted under the peak flexibility or super-peak flexibility categories.

The ISO structured the flexible capacity categories to meet the following needs:

Base Flexibility: Operational needs determined by the magnitude of the largest 3-hour secondary net load[9] ramp

Peak Flexibility: Operational need determined by the difference between 95 percent of the maximum 3-hour net load ramp and the largest 3-hour secondary net load ramp

Super-Peak Flexibility: Operational need determined by five percent of the maximum 3-hour net load ramp of the month

These categories include different minimum flexible capacity operating characteristics and different limits on the total quantity of flexible capacity within each category. In order to calculate the quantities needed in each flexible capacity category, the ISO conducted a three-step assessment process:

1) Calculate the forecast percentages needed in each category in each month;
2) Analyze the distributions of both largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations; and
3) Calculate a simple average of the percent of base flexibility needs from all months within a season.

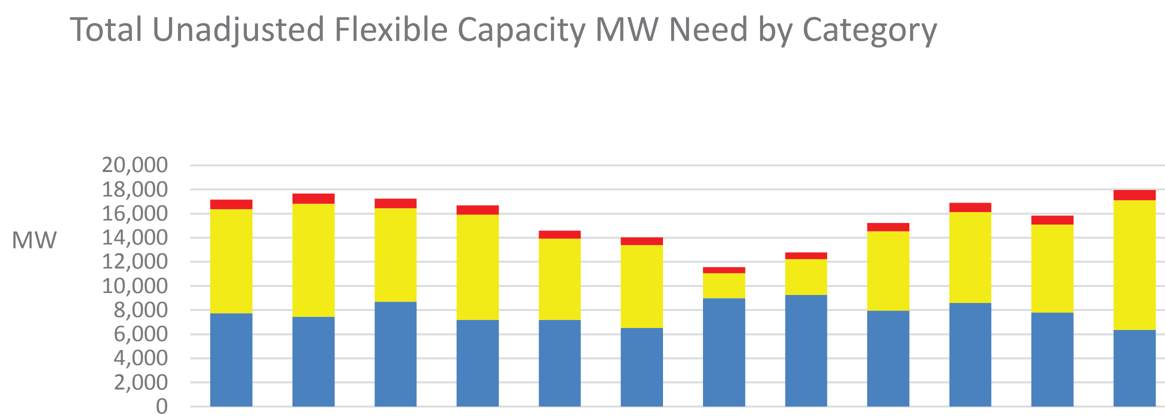
6.1 Calculating the Forecast Percentages Needed in Each Category in Each Month

Based on the categories defined above, the ISO calculated the system level needs for 2019 based only on the maximum monthly 3-hour net load calculation. Then the ISO calculated the quantity needed in each category in each month based on the above descriptions. The ISO calculated the secondary net load ramps to eliminate the possibility of over-lapping time intervals between the primary and secondary net load ramps. The ISO then added the contingency requirements into the categories proportionally to the percentages established by the maximum 3-hour net load ramp. The CASISO distributed contingency reserve to three category by the proportions of the corresponding categories.

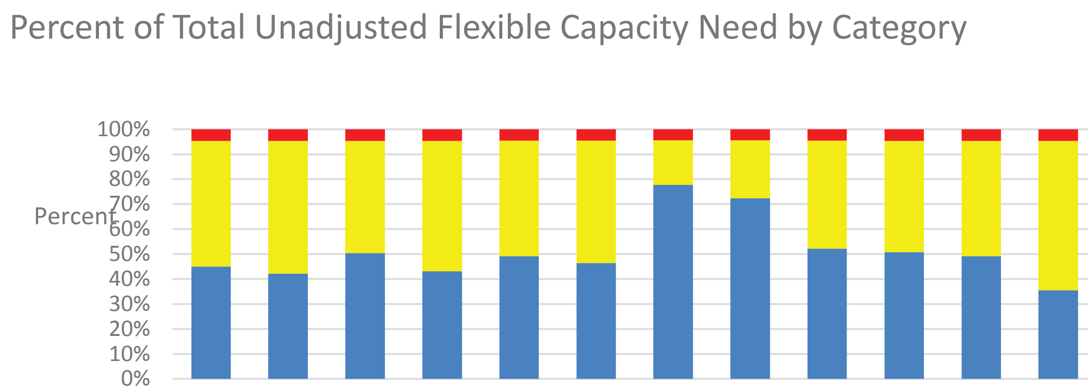
[9] The largest daily secondary 3-hour net-load ramp is calculated as the largest net load ramp that does not correspond with the daily maximum net-load ramp. For example, if the daily maximum 3-hour net-load ramp occurs between 5:00 p.m. and 8:00 p.m., then the largest secondary ramp would be determined by the largest morning 3-hour net-load ramp.

The calculation of flexible capacity needs for each category for 2019 is shown in Figure 3.

Figure 3: ISO System-Wide Flexible Capacity Monthly Calculation by Category for 2019



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	805	830	811	775	670	641	503	564	685	780	738	842
Peak Flexibility	8,634	9,379	7,742	8,713	6,750	6,868	2,070	2,971	6,580	7,535	7,310	10,745
Base Flexibility	7,730	7,444	8,694	7,191	7,172	6,513	8,980	9,243	7,952	8,589	7,782	6,369



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	805	830	811	775	670	641	503	564	685	780	738	842
Peak Flexibility	8,634	9,379	7,742	8,713	6,750	6,868	2,070	2,971	6,580	7,535	7,310	10,745
Base Flexibility	7,730	7,444	8,694	7,191	7,172	6,513	8,980	9,243	7,952	8,589	7,782	6,369

Again, the larger quantity of existing and incremental grid connected and behind-the-meter solar PV results in a greater difference between the primary and secondary net load ramps, particularly in the non-summer months. This results in a lower percent requirement for base flexible capacity resources compared to last year's study.

6.2 Analyzing Ramp Distributions to Determine Appropriate Seasonal Demarcations

To determine the seasonal percentages for each flexible capacity category, the ISO analyzed the distributions of the largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations for the base flexibility category. The secondary net load ramps provide the ISO with the frequency and magnitude of secondary net load ramps. Assessing these distributions helps the ISO identify seasonal differences that are needed for the final determination of percent of each category of flexible capacity that is needed. Although this year's assessment focused on the data produced in this study process, the ISO also referred back to last year's[10] assessment to confirm that the patterns persist. The primary and secondary net load ramp distributions are shown for each month in Figures 4 and 5 respectively.

---

[10] Last year's assessment refers to the 2018 Flexible Capacity Needs Assessment. The ISO has changed the naming convention to refer to the RA year, and not the year in which the study was conducted.

Figure 4: Distribution of Daily Primary 3-hour Net Load Ramps for 2019

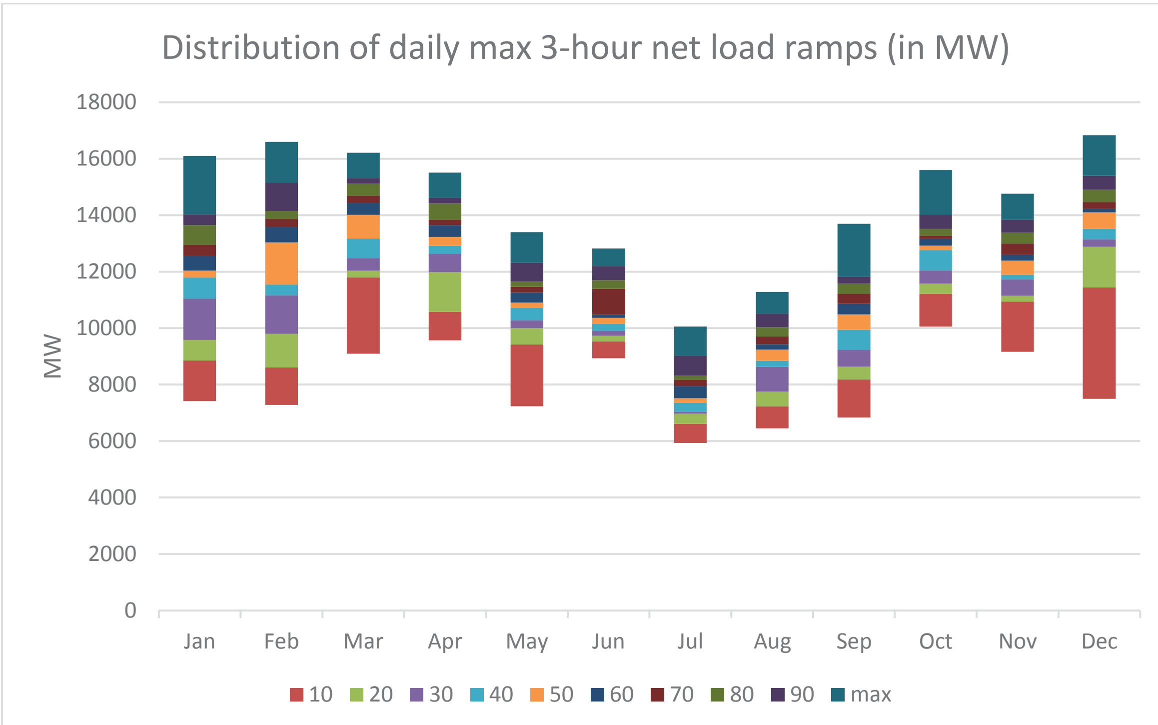
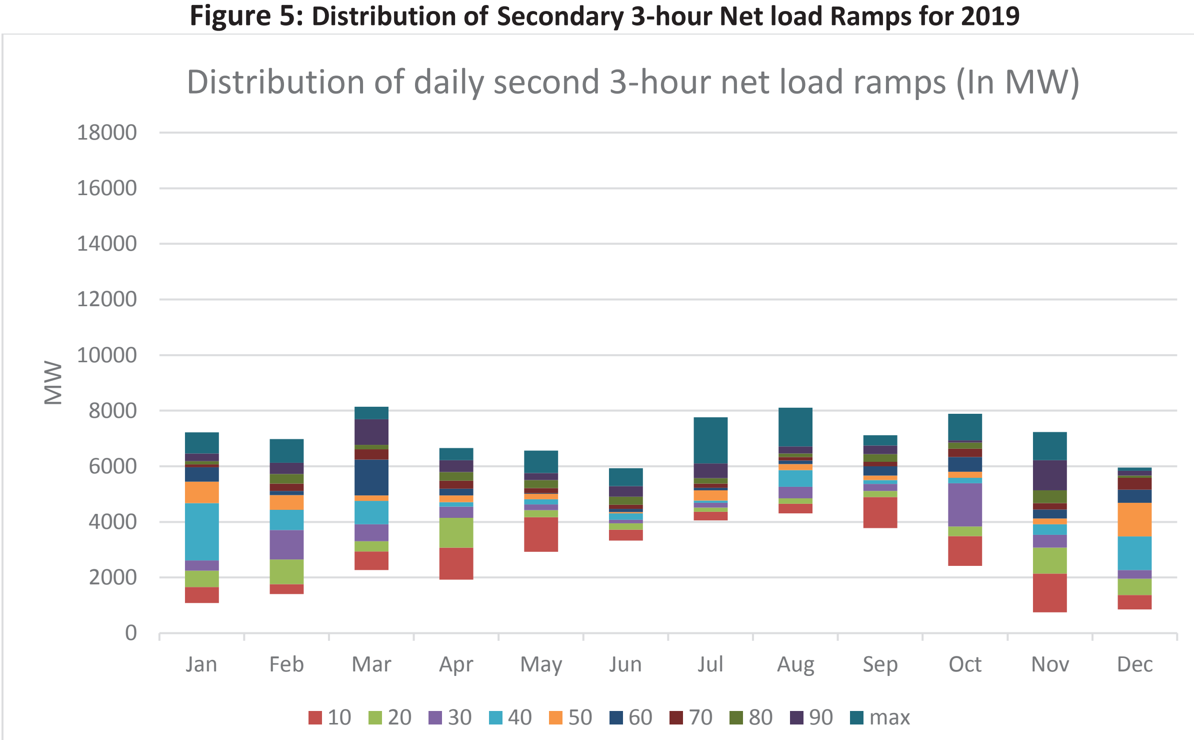


Figure 5: Distribution of Secondary 3-hour Net load Ramps for 2019



As Figure 4 shows, the distribution (*i.e*. the height of the distribution for each month) of the daily maximum three-hour net load ramps is slightly smaller during the summer months. The maximum three-hour net load ramps for May and September are slightly higher than seen in previous years. This is due in large part to these months being transitional months where some days are similar to summer days, while other days are similar to non-summer days. In other words, these months can exhibit a wide range of daily net-load profiles. Transitional months like May and September differ slightly from their seasonal counterparts, but not sufficiently to warrant changes to any seasonal treatment for those months. Further, the daily secondary three-hour net load ramps are also similar, except for May and September.[11] These distributions indicate two traits. First, given the magnitude of this distribution, it is unlikely that all base flexible capacity resources will be used for two ramps every day. The base flexibility resources were designed to address days with two separate significant net load ramps. The distributions of these secondary net load ramps indicates that the ISO does not need to set seasonal percentages in the base flexibility category at the percentage of the higher month within that season. Second, because there are still numerous bimodal ramping days in the distribution, many of the base flexibility resources will still be needed to address bimodal ramping needs. Accordingly, the ISO must ensure there is sufficient base ramping for all days of the month. Further, particularly for summer months, the ISO did not identify two distinct ramps each day. Instead, the secondary net-load ramp may be a part of single long net load ramp.

Figures 3-5 shows that the seasonal divide established in last year's assessment remains reasonable. The distributions of the primary and secondary ramps provide additional support for the summer/non-summer split. Accordingly, the ISO proposes to maintain two flexible capacity needs seasons that mirror the existing summer season (May through September) and non-summer season (January through April and October through December) used for resource adequacy. This approach has two benefits.

First, it mitigates the impact that variations in the net load ramp in any given month can have on determining the amounts for the various flexible capacity categories for a given season. For example, a month may have either very high or low secondary ramps that are simply the result of the weather in the year. However, because differences in the characteristics of net load ramps are largely due to variations in the output of variable energy resources, and these variations are predominantly due to weather and seasonal conditions, it is reasonable to break out the flexibility categories by season. Because the main differences in weather in the ISO

---

[11] The secondary net load ramp for May 20 was deleted due to the fact that it was clear outlier, at 9,279 MW.

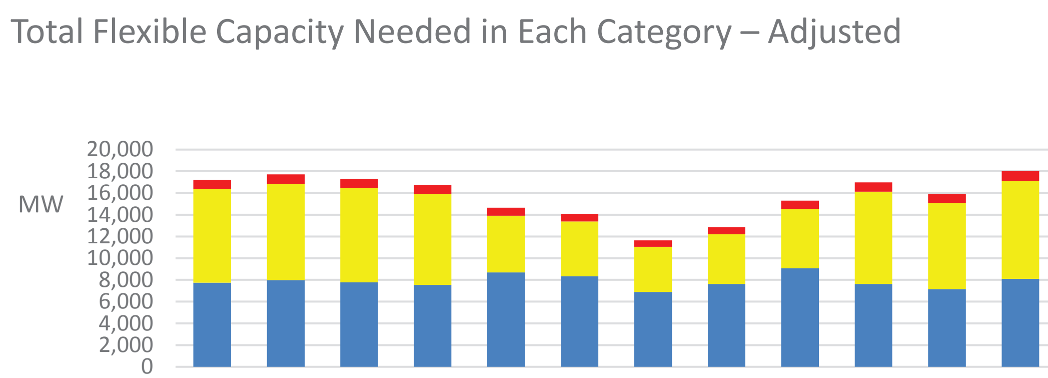
system are between summer and non-summer months, the ISO proposes to use this as the basis for the seasonal breakout of the needs for the flexible capacity categories.

Second, adding flexible capacity procurement to the RA program will increase the process and information requirements. Maintaining a seasonal demarcation that is consistent with the current RA program will reduce the potential for errors in resource adequacy showings.

6.3 Calculate a Simple Average of the Percent of Base Flexibility Needs

The ISO calculated the percentage of base flexibility needed using a simple average of the percent of base flexibility needs from all months within a season. Based on that calculation, the ISO proposes that flexible capacity meeting the base-flexibility category criteria comprise 45 percent of the ISO system flexible capacity need for the non-summer months and 59 percent for the summer months. Peak flexible capacity resources could be used to fulfill up to 45 percent of non-summer flexibility needs and 59 percent of summer flexible capacity needs. The super-peak flexibility category is fixed at a maximum five percent across the year. These percentages are significantly different than those of in the 2018 Flexible Capacity Needs Assessment. As with the increase in the flexible capacity need, the change is largely attributable to the continued growth of both grid connected and behind-the-meter solar. The increase in grid connected solar and incremental behind-the-meter solar will reduce the secondary net load ramp in the non-summer months, but will increase the primary net load ramp, which reduces the percentage of base-ramping capacity in the non-summer months. However, it would have the opposite effect in the summer months. The ISO's proposed system-wide flexible capacity categories are provided in Figure 6.

Figure 6: System-wide Flexible Capacity Need in Each Category for 2019



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	861	885	865	837	733	704	582	643	765	849	794	901
Peak Flexibility	8,612	8,852	8,649	8,369	5,239	5,035	4,158	4,596	5,468	8,485	7,942	9,005
Base Flexibility	7,753	7,970	7,787	7,535	8,683	8,346	6,892	7,618	9,064	7,639	7,150	8,108

7. Allocating the Flexible Capacity Needs to Local Regulatory Authorities

The ISO's allocation methodology is based on the contribution of a local regulatory authority's LSEs to the maximum 3-hour net load ramp.

Specifically, the ISO calculated the LSEs under each local regulatory authority's contribution to the flexible capacity needs using the following inputs:

1) The maximum of the most severe single contingency or 3.5 percent of forecasted peak load for each LRA based on its jurisdictional LSEs' peak load ratio share

2) Δ Load – LRA's average contribution to load change during top five daily maximum three-hour net load ramps within a given month from the previous year x total change in ISO load

3) Δ Wind Output – LRA's average percent contribution to changes in wind output during the five greatest forecasted 3-hour net load changes x ISO total change in wind output during the largest 3-hour net load change

4) Δ Solar PV – LRA's average percent contribution to changes in solar PV output during the five greatest forecasted 3-hour net load changes x total change in solar PV output during the largest 3-hour net load change

5) Δ BTM Solar – LRA's average percent contribution to changes in BTM solar PV output during the five greatest forecasted 3-hour net load changes x total change in BTM solar output during the largest 3-hour net load change

These amounts are combined using the equation below to determine the contribution of each LRA, including the CPUC and its jurisdictional load serving entities, to the flexible capacity need.

Flexible Capacity Need = Δ Load – Δ Wind Output – Δ Solar PV – Δ BTM Solar + (3.5% * Expected Peak * Peak Load Ratio Share)

The ISO calculates the average contribution of Δ Load using the change of the proportion of load at the end of the ramp minus the proportion of load at the start of the ramp. The resulting calculations provided stable results.

$$\Delta L_{sc,2019} = L^{E}_{sc,2017}\left(\frac{L^{E}_{2019}}{L^{E}_{2017}}\right) - L^{S}_{sc,2017}\left(\frac{L^{S}_{2019}}{L^{S}_{2017}}\right),$$

where $L = Load$,

2017 has metered load, 2019 has forecasted load

$S =$ ramping start time, $E =$ramping end time,

Subscript sc is for each RALSE scheduling coordinator.

Therefore, when sum (Σ) it over all sc, we have

$$\Sigma \Delta L_{sc,2019} = \Delta L_{2019}$$

Any LRA with a negative contribution to the flexible capacity need is limited to a zero megawatt allocation, not a negative contribution. As such, the total allocable share of all LRAs may sum to a number that is slightly larger than the flexible capacity need.[12] The ISO does not currently have a process by which a negative contribution could be reallocated or used as a

[12] Some small LRAs had negative contributions to the flexible capacity needs. The ISO is proposing to change this limitation as part of the Flexible Resource Adequacy Criteria and Offer Obligation – Phase 2 stakeholder initiative. However, this initiative is not yet complete, and thus the ISO cannot modify this rule.

credit for another LRA or LSE. The ISO is examining ways to address this issue as part of the Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 stakeholder initiative.

The ISO has made available all non-confidential working papers and data that the ISO relied on for the Final Flexible Capacity Needs Assessment for 2019.[13] Specifically, the ISO has posted materials and data used to determine the monthly flexible capacity needs, the contribution of CPUC jurisdictional load serving entities to the change in load, and seasonal needs for each flexible capacity category. This data is available at

http://www.caiso.com/Documents/2018DraftFlexibleCapacityNeedsAssessment_2019NetLoadData.xlsx.

Table 2 shows the final calculations of the individual contributions of each of the inputs to the calculation of the maximum 3-hour continuous net load ramp at a system level.

Table 2: Contribution to Maximum 3-hour Continuous Net load Ramp for 2019

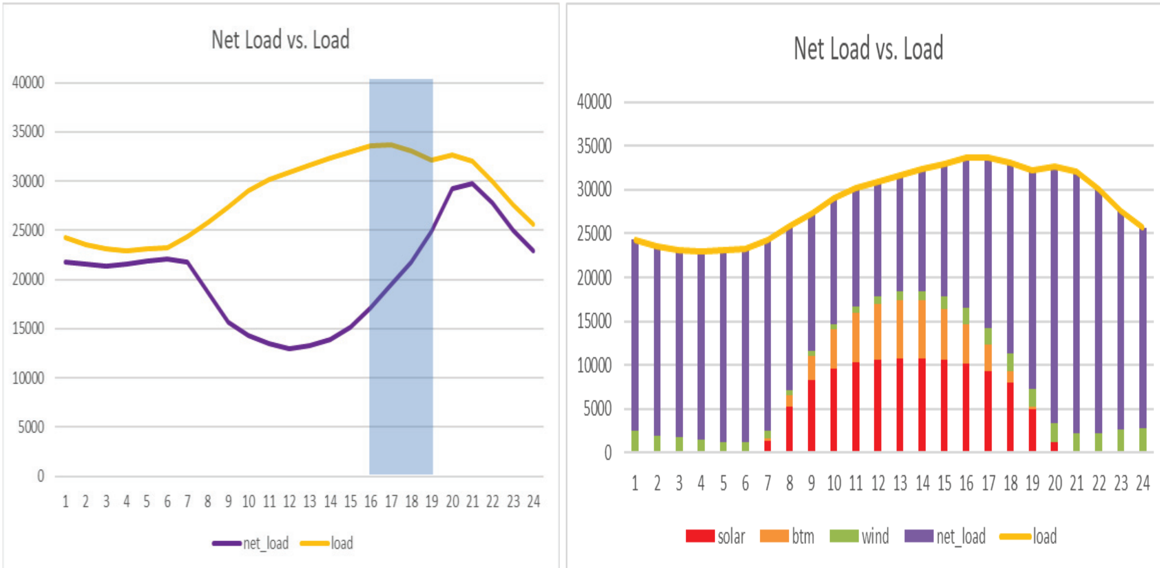
Month	Average of Load contribution 2019	Average of solar contribution 2019	Average of Wind contribution 2019	Average of BTM contribution 2019	Total percent 2019
January	29.13%	-52.69%	-18.94%	0.76%	100%
February	26.97%	-50.90%	-21.08%	-1.05%	100%
March	25.33%	-61.51%	-19.91%	6.75%	100%
April	21.91%	-56.04%	-23.99%	1.94%	100%
May	17.35%	-66.41%	-19.67%	3.44%	100%
June	13.45%	-68.53%	-21.25%	3.22%	100%
July	-7.31%	-80.63%	-30.30%	3.61%	100%
August	-2.49%	-79.51%	-25.90%	2.91%	100%
September	0.05%	-71.23%	-25.72%	-2.99%	100%
October	15.72%	-59.80%	-18.84%	-5.64%	100%
November	14.63%	-55.13%	-24.43%	-5.80%	100%
December	31.48%	-48.17%	-14.67%	-5.68%	100%

As the CAISO system includes more wind and solar generation, the net load ramp and load ramp do not always act in sync. In some months, the main driver for net load ramp is the decreased solar generation after noon time, while the load is leveling off or declining. In such

[13] There were no revisions to the data posted for the draft report.

situations, the load contribution to the net load ramp will approach to zero even negative. Figure 7 below captures this phenomenon.

Figure 7: Understanding Negative Contributions of Load



As Table 2 shows, Δ Load is not the largest contributor to the net load ramp during the summer months because the incremental solar PV mitigates morning net load ramps. This changed the timing of the largest net load ramps and changed the Δ Load impact on the net load ramps. However, the percentage contribution of load to the net load ramp is down in all months compared to last year's study. Again, this is attributable to the inclusion of the incremental behind-the-meter solar resources. The behind-the-meter solar resources are leading to maximum three-hour net load ramps during summer months that occur in the afternoon. This is particularly evident during July and August, when the contribution of delta load is negative. This implies that load is less at the end of the net load ramp than it was at the beginning. This is caused by the timing of the largest three net load ramp in July and August. It typically occurs midday and when both load and solar are decreasing. Further, the contribution of solar PV resources has increased relative to last year's study and remains a significant driver of the three-hour net load ramps.

Consistent with the ISO's flexible capacity needs allocation methodology, the ISO used 2017 actual load data to determine each local regulatory authority's contribution to the Δ Load component. The ISO calculated minute-by-minute net load curves for 2017. Then, using the same methodology it used for determining the maximum 3-hour continuous net load ramp described above, the ISO calculated the maximum three-hour net load ramps for 2017 and applied the Δ load calculation methodology described above. The ISO used settlements data to determine the LRA's contribution the Δ load component. This data is generated in 10-minute increments. This number may be the same for some LSEs over the entire hour. The ISO smoothed these observations by using a 60-minute rolling average of the load data. This allowed the ISO to simulate a continuous ramp using actual settled load data.

Based on this methodology, the ISO determined the flexible capacity need attributable to the CPUC jurisdictional LSEs.[14 & 15] Next, the ISO multiplied the flexible capacity needs from Figure 2 and the contribution to each factor to determine the relative contribution of each component at a system level. The ISO then multiplied the resultant numbers by the Local Regulatory Authority's calculated contribution to each individual component. Finally, the ISO added the 3.5 percent expected peak load times the LRA's peak load ratio share. The resulting CPUC allocations are shown in Table 4 and Figure 8. The contributions are calculated by LRA and LRA will only be provided the contribution of its jurisdictional LRA as per section 40.10.2.1 of the ISO tariff.

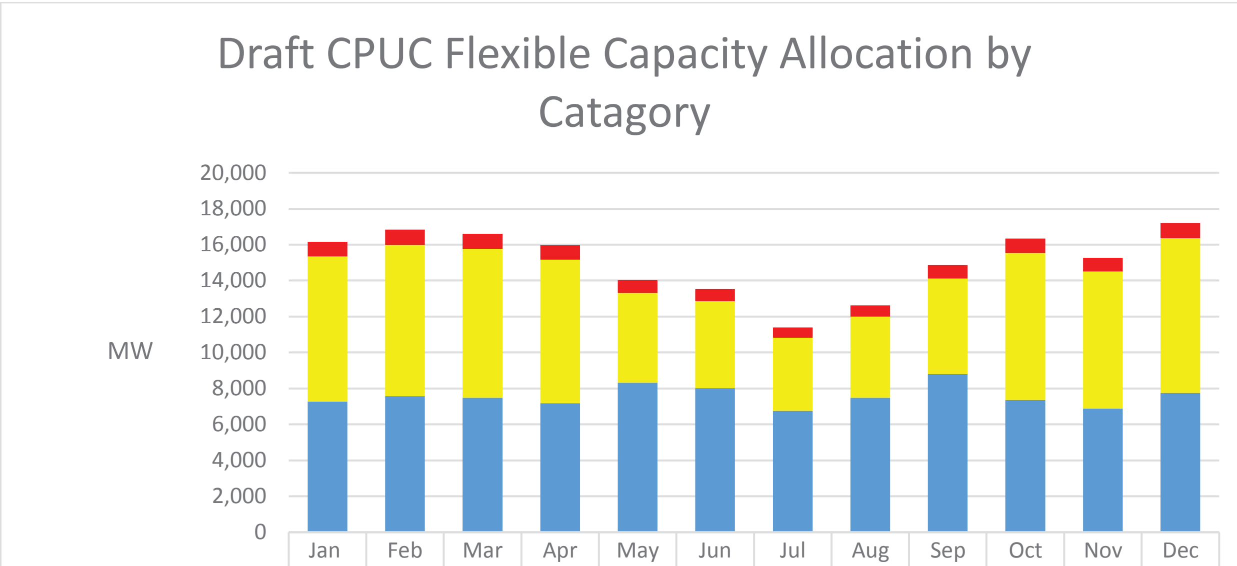
Table 4: CPUC Jurisdictional LSEs' Contribution to Flexible Capacity Needs

	Δ Load MW	Δ PV Fixed MW	Δ BTM Solar MW	Δ Wind MW	3.5% expected peak load* Peak load ration share 2018	Total Allocation
Jan	4189	8045	3015	-119	1025	16156
Feb	4174	8026	3461	168	1001	16830
Mar	4014	9471	3193	-1057	984	16605
Apr	3202	8253	3680	-291	1115	15960
May	2274	8456	2609	-445	1129	14022
Jun	1751	8347	2695	-399	1141	13535
Jul	-396	7699	3013	-351	1427	11392
Aug	107	8518	2889	-317	1427	12624
Sep	264	9270	3486	396	1443	14859
Oct	2488	8861	2907	850	1240	16346
Nov	2137	7730	3568	826	1018	15278
Dec	5058	7720	2443	923	1064	17208

[14] Because the Energy Division proposal states that the CPUC will allocate flexible capacity requirements to its jurisdictional LSEs based on peak load ratio share, the ISO has not calculated the individual contribution of each LSE.

Finally, the ISO applied the seasonal percentage established in section 6 to the contribution of CPUC jurisdictional load serving entities to determine the quantity of flexible capacity needed in each flexible capacity category. These results are detailed in figure 8.

Figure 8: CPUC Flexible Capacity Need in Each Category for 2018



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	808	841	830	798	701	677	570	631	743	817	764	860
Peak Flexibility	8,077	8,414	8,301	7,979	5,013	4,839	4,073	4,513	5,312	8,172	7,638	8,603
Base Flexiblity	7,272	7,575	7,474	7,183	8,308	8,020	6,750	7,480	8,804	7,357	6,876	7,745

8. Determining the Seasonal Must-Offer Obligation Period

Under ISO tariff sections 40.10.3.3 and 40.10.3.4, the ISO establishes, by season, the specific five-hour period during which flexible capacity counted in the peak and super-peak categories will be required to submit economic energy bids into the ISO market (*i.e.* have an economic bid must-offer obligation). Whether the ISO needs peak and super-peak category resources more in the morning or afternoon depends on when the larger of the two ramps occurs. The average net load curves for each month provide the most reliable assessment of whether a flexible capacity resource would be greatest benefit in the morning or evening net load ramps. The ISO looked at the average ramp over the day to see if the bigger ramp was in the morning or afternoon and then set the hours for the must-offer obligation accordingly. The ISO calculated the maximum three-hour net load for all months. Table 5 shows the hours in which the maximum monthly average net load ramp began.

Table 5: 2019Forecasted Hour in Which Monthly Maximum 3-Hour Net load Ramp Began

	Frequency of All Three Hour Net Load Ramp Start Hour ramp Start						
Month	11:00	12:00	13:00	14:00	15:00	16:00	17:00
January				28	3		
February				12	16		
March				2	28	1	
April					17	13	
May				1		30	
June						27	3
July		1				30	
August		1	2			28	
September	2	1	3	3	21		
October				13	18		
November		1	2	27			
December			1	29	1		

Based on the data for all daily maximum three hour net load ramps, the ISO believes that the appropriate flexible capacity must-offer obligation period for peak and super-peak flexible capacity categories is HE 14 through HE 19 for January through April and October through December; HE 15 through HE 20 for May through September. These hours are the same from those in Final Flexible Capacity Needs Assessment for 2018. The hours above for all seasons are one hour earlier than the hours established in the 2018 assessment.

Given that the ISO is proposing a change to both must-offer obligation seasons, the ISO also reviewed the timing of the top five net load ramps to confirm that the intervals also capture the largest net load ramps. As shown above, the newly proposed intervals do, in fact capture the intervals of the largest ramps, too. Both of these changes are consistent with continued solar growth and reflect the fact that the initial solar drop-off is a primary driver of the three-hour net load ramp. This is further supported by the contributing factors shown in Table 2, above.

The ISO continues to believe it is appropriate to align the must-offer obligations with the summer/non-summer demarcation used for the RA program and contributions to the categories described above. Because these months align with the with the summer/non-summer demarcation in the RA program and aforementioned contributions to the categories, the ISO expects that this will also make the procurement process less complicated.

9. Next Steps

The ISO will commence the flexible capacity needs assessment to establish the ISO system flexible capacity needs for 2020 in early 2019. The ISO will continue to assess the modeling approach used for distributed solar resources, further review methods to address year-to-year volatility, and account for potential controllability of some variable energy resources.

Attachment B

Draft Local Capacity Technical Analysis

California Independent System Operator Corporation

2019 LOCAL CAPACITY TECHNICAL ANALYSIS

DRAFT REPORT AND STUDY RESULTS

April 23, 2018

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2019 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2019 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2017. On balance, the assumptions, processes, and criteria used for the 2019 LCT Study mirror those used in the 2007-2018 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2019 LCT study results are provided to the CPUC for consideration in its 2019 resource adequacy requirements program. These results will also be used by the CAISO as "Local Capacity Requirements" or "LCR" (minimum quantity of local capacity necessary to meet the LCR criteria) and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Standards notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2]

The load forecast used in this study is based on the final adopted California Energy Demand Updated Forecast, 2018-2030 developed by the CEC; namely the load-serving entity (LSE) and balancing authority (BA) mid baseline demand with low additional achievable energy efficiency and photo voltaic (AAEE-AAPV), posted on 2/21/2018: http://www.energy.ca.gov/2017_energypolicy/documents/index.html#02212018.

[1] The LSAG consists of a representative cross-section of stakeholders, technically qualified to assess the issues related to the study assumptions, process and criteria of the existing LCT Study methodology and to recommend changes, where needed.

[2] For information regarding the conditions under which the CAISO may engage in procurement of local capacity and the allocation of the costs of such procurement, please see Sections 41 and 43 of the current CAISO Tariff, at: http://www.caiso.com/238a/238acd24167f0.html.

Below is a comparison of the 2019 vs. 2018 total LCR:

2019 Local Capacity Requirements

	Qualifying Capacity			2019 LCR Need Based on Category B***			2019 LCR Need Based on Category C*** with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	0	202	202	116	0	**116**	165	0	**165**
North Coast / North Bay	119	771	890	689	0	**689**	689	0	**689**
Sierra	1146	1004	2150	1362	0	**1362**	1964	283*	**2247**
Stockton	144	489	633	405	5*	**410**	427	350*	**777**
Greater Bay	628	6448	7076	3670	0	**3670**	4461	0	**4461**
Greater Fresno	340	3177	3517	1406	0	**1406**	1670	1*	**1671**
Kern	13	462	475	148	6*	**154**	472	6*	**478**
LA Basin	1445	9421	10866	7968	0	**7968**	8116	0	**8116**
Big Creek/ Ventura	424	4545	4969	2333	0	**2333**	2614	0	**2614**
San Diego/ Imperial Valley	106	4285	4391	4026	0	**4026**	4026	0	**4026**
Total	4365	30804	35169	22123	11	**22134**	24604	640	**25244**

2018 Local Capacity Requirements

	Qualifying Capacity			2018 LCR Need Based on Category B***			2018 LCR Need Based on Category C*** with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	14	196	210	121	0	**121**	169	0	**169**
North Coast / North Bay	118	751	869	634	0	**634**	634	0	**634**
Sierra	1176	949	2125	1215	0	**1215**	1826	287*	**2113**
Stockton	139	466	605	358	0	**358**	398	321*	**719**
Greater Bay	1008	6095	7103	3910	0	**3910**	5160	0	**5160**
Greater Fresno	364	3215	3579	1949	0	**1949**	2081	0	**2081**
Kern	15	551	566	0	0	**0**	453	0	**453**
LA Basin	1556	9179	10735	6873	0	**6873**	7525	0	**7525**
Big Creek/ Ventura	430	5227	5657	2023	0	**2023**	2321	0	**2321**
San Diego/ Imperial Valley	202	4713	4915	4032	0	**4032**	4032	0	**4032**
Total	5022	31342	36364	21115	0	**21115**	24599	608	**25207**

* No local area is “overall deficient”. Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.
***TPL 002 Category B is generally equivalent to TPL 001-4 Category P1. TPL 003 Category C is generally equivalent to TPL 001-4 P2 through P7. Current LCR study report is compliant with existing language in the ISO Tariff section 40.3.1.1 Local Capacity Technical Study Criteria to be revised at a later date.

Overall, the LCR needs have increased by about 37 MW or about 0.0% from 2018 to 2019.

The LCR needs have decreased in the following areas: Humboldt and Fresno due to downward trend for load; Bay Area due to transmission projects; San Diego due to downward trend for load combined with an increase due loss of NQC at the most effective location in mitigating the most limiting contingency.

The LCR needs have increased in North Coast/North Bay, Stockton, LA Basin and Big Creek/Ventura due to load increase; Sierra due to load and resource distribution compared to the most limiting contingency; Kern due to change in most limiting element.

The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between 2019 and 2018 local capacity requirements.

Table of Contents

II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the previous annual LCT Studies, the intent of the 2019 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2019 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2019 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2017.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2019 LCT Study:

Summary Table of Inputs and Methodology Used in this LCT Study:

Issue:	How are they incorporated into this LCT study:
<u>Input Assumptions:</u>	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year
• Load Forecast	Uses a 1-in-10 year summer peak load forecast
<u>Methodology:</u>	
• Maximize Import Capability	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• QF/Nuclear/State/Federal Units	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCT Study.
• Maintaining Path Flows	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the South of Lugo transfer path flowing into the LA Basin.
<u>Performance Criteria:</u>	
• Performance Level B & C, including incorporation of PTO operational solutions	This LCT Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, of the study year. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study.
<u>Load Pocket:</u>	
• Fixed Boundary, including limited reference to published effectiveness factors	This LCT Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2019 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the Reliability Standards of the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council ("WECC") Regional Criteria (collectively "Reliability Standards"). The Reliability Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the Reliability Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the Reliability Standards.[3] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the Reliability Standards as well as reliability criteria adopted by the CAISO (Grid Planning Standards).

The Reliability Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The Reliability Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

[3] Pub. Utilities Code § 345

D. Application of N-1, N-1-1, and N-2 Criteria

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions Category A (N-0) the CAISO must protect for all single contingencies Category B (N-1) and common mode Category C5 (N-2) double line outages. Also, after a single contingency, the CAISO must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as requirement R1.1 of the WECC Regional Criteria[3] ("two adjacent circuits") with no manual system adjustment between the two contingencies.

E. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCT Report is based on NERC performance level B and performance level C standard. The NERC Standards refer mainly to system being stable and both thermal and voltage limits be within applicable ratings. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC regional criteria that further specifies the dynamic and reactive margin requirements for the same NERC performance levels. These performance levels can be described as follows:

a. <u>LCR Performance Criteria- Category B</u>

Category B describes the system performance that is expected immediately following the loss of a single transmission element, such as a transmission circuit, a generator, or a transformer.

Category B system performance requires that system is stable and all thermal and voltage limits must be within their “Applicable Rating,” which, in this case, are the emergency ratings as generally determined by the PTO or facility owner. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met; however there is no guarantee that facilities are returned to within normal ratings or to a state where it is safe to continue to operate the system in a reliable manner such that the next element out will not cause a violation of the Applicable Ratings.

b. LCR Performance Criteria- Category C

The Reliability Standards require system operators to “look forward” to make sure they safely prepare for the “next” N-1 following the loss of the “first” N-1 (stay within Applicable Ratings after the “next” N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the “first” and “next” element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a “Special Protection Scheme” that would remove pre-identified load from service upon the loss of the “next “ element.[4] All Category

[4] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because

C requirements in this report refer to situations when in real time (N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing Reliability Standards.

Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

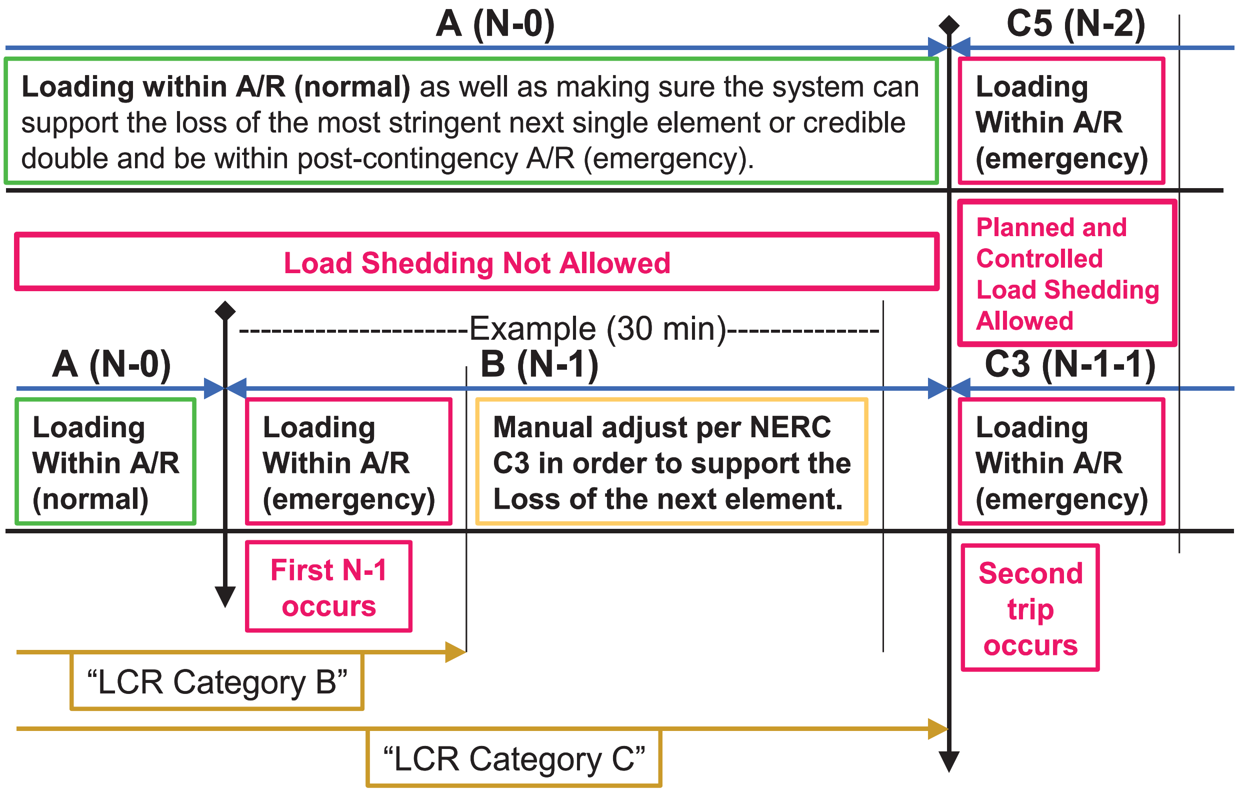
c. CAISO Statutory Obligation Regarding Safe Operation

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Standards at all times, for example during normal operating conditions Category **A (N-0)** the CAISO must protect for all single contingencies Category **B (N-1)** and common mode Category **C5 (N-2)** double line outages. As a further example, after a single contingency the CAISO must readjust the system in order to be able to support the loss of the next most stringent contingency Category **C3 (N-1-1)**.

---

sometimes these systems will operate when not required and other times they will not operate when needed.

Figure 1: Temporal graph of LCR Category B vs. LCR Category C:



The following definitions guide the CAISO's interpretation of the Reliability Standards governing safe mode operation and are used in this LCT Study:

Applicable Rating:

This represents the equipment rating that will be used under certain contingency conditions.

Normal rating is to be used under normal conditions.

Long-term emergency ratings, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

*Temperature-adjusted ratings* shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

*CAISO Transmission Register* is the only official keeper of all existing ratings mentioned above.

*Ratings for future projects* provided by PTO and agree upon by the CAISO shall be used.

*Other short-term ratings* not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

*Path Ratings* need to be maintained within their limits in order to assure that proper capacity is available in order to operate the system in real-time in a safe operating zone.

Controlled load drop:

This is achieved with the use of a Special Protection Scheme.

Planned load drop:

This is achieved when the most limiting equipment has short-term emergency ratings AND the operators have an operating procedure that clearly describes the actions that need to be taken in order to shed load.

Special Protection Scheme:

All known SPS shall be assumed. New SPS must be verified and approved by the CAISO and must comply with the new SPS guideline described in the CAISO Planning Standards.

System Readjustment:

This represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

Actions that can be taken as system readjustment after a single contingency (Category B):

1. System configuration change – based on validated and approved operating procedures
2. Generation re-dispatch
   a. Decrease generation (up to 1150 MW) – limit given by single contingency SPS as part of the CAISO Grid Planning standards (ISO G4)
   b. Increase generation – this generation will become part of the LCR need

Actions, which shall not be taken as system readjustment after a single contingency (Category B):

1. Load drop – based on the intent of the CAISO/WECC and NERC standards for category B contingencies.

The NERC Transmission Planning Standards footnote mentions that load shedding can be done after a category B event in certain local areas in order to maintain compliance with performance criteria. However, the main body of the criteria spells out that no dropping of load should be done following a single contingency. All stakeholders and the CAISO agree that no involuntary interruption of load should be done immediately after a single contingency. Further, the CAISO and stakeholders now agree on the viability of dropping load as part of the system readjustment period – in order to protect for the next most limiting contingency. After a single contingency, it is understood that the system is in a Category B condition and the system should be planned based on the body of the criteria with no shedding of load regardless of whether it is done immediately or in 15-30 minute after the original contingency. Category C conditions only arrive after the second contingency has happened; at that point in time, shedding load is allowed in a planned and controlled manner.

A robust California transmission system should be, and under the LCT Study is being, planned based on the main body of the criteria, not the footnote regarding Category B contingencies. Therefore, if there are available resources in the area, they are looked to meet reliability needs (and included in the LCR requirement) before resorting to involuntary load curtailment. The footnote may be applied for criteria compliance issues only where there are no resources available in the area.

Time allowed for manual readjustment:

Tariff Section 40.3.1.1, requires the CAISO, in performing the Local Capacity Technical Study, to apply the following reliability criterion:

Time Allowed for Manual Adjustment: This is the amount of time required for the Operator to take all actions necessary to prepare the system for the next Contingency. The time should not be more than thirty (30) minutes.

The CAISO Planning Standards also impose this manual readjustment requirement. As a parameter of the Local Capacity Technical Study, the CAISO must assume that as the system operator the CAISO will have sufficient time to:

(1) make an informed assessment of system conditions after a contingency has occurred;

(2) identify available resources and make prudent decisions about the most effective system redispatch;

(3) manually readjust the system within safe operating limits after a first contingency to be prepared for the next contingency; and

(4) allow sufficient time for resources to ramp and respond according to the operator's redispatch instructions. This all must be accomplished within 30 minutes.

Local capacity resources can meet this requirement by either (1) responding with sufficient speed, allowing the operator the necessary time to assess and redispatch resources to effectively reposition the system within 30 minutes after the first contingency, or (2) have sufficient energy available for frequent dispatch on a pre-contingency basis to ensure the operator can meet minimum online commitment constraints or reposition the system within 30 minutes after the first contingency occurs. Accordingly, when evaluating resources that satisfy the requirements of the CAISO Local Capacity Technical Study, the CAISO assumes that local capacity resources need to be available in no longer than 20 minutes so the CAISO and demand response providers have a reasonable opportunity to perform their respective and necessary tasks and enable the CAISO to reposition the system within the 30 minutes in accordance with applicable reliability criteria.

F. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution "options" with varying ranges of potential service reliability consistent with CAISO's Planning Standard. The CAISO applies Option 2 for its purposes of identifying necessary local capacity needs and the corresponding potential scope of its backstop authority. Nevertheless, the CAISO continues to provide Option 1 as a point of reference for the CPUC and Local Regulatory Authorities in considering procurement targets for their jurisdictional LSEs.

1. Option 1- Meet LCR Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Standard that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[5]

---

5 This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

2. Option 2- Meet LCR Performance Criteria Category C and Incorporate Suitable Operational Solutions

Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption) developed and approved by the CAISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers under normal or single contingency conditions as the CAISO operators prepare for the second contingency. However, the customer load may be interrupted in the event the second contingency occurs.

As noted, Option 2 is the local capacity level that the CAISO requires to reliably operate the grid per NERC, WECC and CAISO standards. As such, the CAISO recommends adoption of this Option to guide resource adequacy procurement.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

The following table provides a comparison of system planning criteria, based on the performance requirements of the NERC Reliability Standard, used in the study:

Table 4: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Standard	Old RMR Criteria	Local Capacity Criteria
A – No Contingencies	X	X	X
B – Loss of a single element			
1. Generator (G-1)	X	X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
C – Loss of two or more elements			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode or Adjacent Circuit) L-2	X		X
6. SLG fault (stuck breaker or protection failure) for G-1	X		
7. SLG fault (stuck breaker or protection failure) for L-1	X		
8. SLG fault (stuck breaker or protection failure) for T-1	X		
9. SLG fault (stuck breaker or protection failure) for Bus section	X		
WECC-R1.2. Two generators (Common Mode) G-2	X[3]		X
D – Extreme event – loss of two or more elements			
Any B1-4 system readjusted (Common Mode or Adjacent Circuit) L-2	X[4]		X[3]
All other extreme combinations D1-14.	X[4]		

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.

2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

4 Evaluate for risks and consequence, per NERC standards.

A significant number of simulations were run to determine the most critical contingencies within each Local Capacity Area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all the contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 4. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

Contingencies	Thermal Criteria[3]	Voltage Criteria[4]
Generating unit [1, 6]	Applicable Rating	Applicable Rating
Transmission line [1, 6]	Applicable Rating	Applicable Rating
Transformer [1, 6]	Applicable Rating[5]	Applicable Rating[5]
(G-1)(L-1) [2, 6]	Applicable Rating	Applicable Rating
Overlapping [6, 7]	Applicable Rating	Applicable Rating

[1] All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners' local area systems.

[2] Key generating unit out, system readjusted, followed by a line outage. This overlapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

[3] Applicable Rating – Based on ISO Transmission Register or facility upgrade plans including established Path ratings.

[4] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.

[5] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[6] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.

[7] During normal operation or following the first contingency (N-1), the generation

must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

Contingencies	Reactive Margin Criteria [2]
Selected [1]	**Applicable Rating**

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

3. Stability Assessment:

Contingencies	Stability Criteria [2]
Selected [1]	**Applicable Rating**

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.

[2] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

B. Load Forecast

1. System Forecast

The California Energy Commission (CEC) derives the load forecast at the system and Participating Transmission Owner (PTO) levels. This relevant CEC forecast is then distributed across the entire system, down to the local area, division and substation level. The PTOs use an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products, GMP), (3) temperature and (4) increased energy efficiency and distributed generation programs.

2. Base Case Load Development Method

The method used to develop the loads in the base case is a melding process that extracts, adjusts and modifies the information from the system, distribution and municipal utility forecasts. The melding process consists of two parts: Part 1 deals with the PTO load and Part 2 deals with the municipal utility load. There may be small differences between the methodologies used by each PTO to disaggregate the CEC load forecast to their level of local area as well as bar-bus model.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division[6] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

The annual division load is determined by summing the previous year division load and the current division load growth. Thus, the key steps are the determination of the initial year division load and the annual load growth. The initial year for the base case development method is based heavily on recorded data. The division load growth in the system base case is determined in two steps. First, the total PTO load growth for the year is determined, as the product of the PTO load and the load growth rate from the system load forecast. Then this total PTO load growth is allocated to the division, based on the relative magnitude of the load growth projected for the divisions by the distribution planners. For example, for the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the latest peak load and temperature data of

---

[6] Each PTO divides its territory in a number of smaller area named divisions. These are usually smaller and compact areas that have the same temperature profile.

the division.

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed must be allocated to those buses. The allocation process is different depending on the load types. For the most part, each PTO classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the system or area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load. The remaining load is allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all loads in the base case is generally higher than the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

The municipal utility forecasts that have been provided to the CEC and PTOs for the purposes of their base cases were also used for this study.

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 21.04 and PowerGem's Transmission Adequacy and Reliability Assessment (TARA) program version 1702. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member and TARA program is commercially available.

To evaluate Local Capacity Areas, the starting base case was adjusted to reflect the latest generation and transmission projects as well as the one-in-ten-year peak load forecast for each Local Capacity Area as provided to the CAISO by the PTOs.

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine and/or TARA software were used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

LCR is defined as the amount of resource capacity that is needed within a Local Capacity Area to reliably serve the load located within this area. The results of the CAISO's analysis are summarized in the Executive Summary Tables.

Table 5: 2019 Local Capacity Needs vs. Peak Load and Local Area Resources

	2019 Total LCR (MW)	Peak Load (1 in10) (MW)	2019 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2019 LCR as % of Total Area Resources
Humboldt	165	187	88%	202	82%
North Coast/North Bay	689	1465	47%	890	77%
Sierra	2247	1758	128%	2150	105%**
Stockton	777	1174	66%	633	123%**
Greater Bay	4461	10274	43%	7076	63%
Greater Fresno	1671	3070	54%	3517	48%**
Kern	478	1088	44%	475	101%**
LA Basin	8116	19266	42%	10866	75%
Big Creek/Ventura	2614	5162	51%	4969	53%
San Diego/Imperial Valley	4026	4412	91%	4391	92%
Total	**25244**	**47856***	**53%***	**35169**	**72%**

Table 6: 2018 Local Capacity Needs vs. Peak Load and Local Area Resources

	2018 Total LCR (MW)	Peak Load (1 in10) (MW)	2018 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2018 LCR as % of Total Area Resources
Humboldt	169	187	90%	210	80%
North Coast/North Bay	634	1333	48%	869	73%
Sierra	2113	1818	116%	2125	99%**
Stockton	719	1169	62%	605	119%**
Greater Bay	5160	10247	50%	7103	73%
Greater Fresno	2081	3290	63%	3579	58%
Kern	453	867	52%	566	80%
LA Basin	7525	18466	41%	10735	70%
Big Creek/Ventura	2321	4802	48%	5657	41%
San Diego/Imperial Valley	4032	4924	82%	4915	82%
Total	**25207**	**47103***	**54%***	**36364**	**69%**

* Value shown only illustrative, since each local area peaks at a time different from the system coincident peak load.

** Resource deficient LCA (or with sub-area that is deficient) – deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

Tables 5 and 6 shows how much of the Local Capacity Area load is dependent on local resources and how many local resources must be available in order to serve the load in those Local Capacity Areas in a manner consistent with the Reliability Criteria. These tables also indicate where new transmission projects, new resource additions or demand side management programs would be most useful in order to reduce the dependency on existing, generally older and less efficient local area resources.

The term "Qualifying Capacity" used in this report is the latest "Net Qualifying Capacity" ("NQC") posted on the CAISO web site at: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Resources scheduled to become operational before 6/1/2019 have been included in this 2019 LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

The first column, "Qualifying Capacity," reflects two sets of resources. The first set is comprised of resources that would normally be expected to be on-line such as Municipal and Regulatory Must-take resources (state, federal, QFs, wind and nuclear units). The second set is "market" resources and it also includes net-seller and solar resources. The second column, "2019 LCR Requirement Based on Category B" identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria-Category B. The third column, "2019 LCR Requirement Based on Category C with Operating Procedure", sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

Based on the existing import allocation methodology, the only major 500 kV constraint not accounted for is path 26 (Midway-Vincent). ***The current method allocates capacity on path 26 similar to the way imports are allocated to LSEs.*** The total resources needed (based on the latest CEC load forecast) in each the two relevant zones, SP26 and NP26 is:

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	26995	4049	-6950	-3750	**20344**
NP26=NP15+ZP26	20082	3012	-3391	-3000	**16703**

Where:

<u>Load Forecast</u> is the most recent 1 in 2 CEC forecast for year 2019 - California Energy Demand Updated Forecast, 2018 - 2030, Mid Demand Baseline, Mid AAEE Savings dated February 21, 2018.

<u>Reserve Margin</u> is 15% the minimum CPUC approved planning reserve margin.

<u>Allocated Imports</u> are the actual 2018 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2019 because there are no additional import transmission additions to the grid.

Allocated Path 26 flow The CAISO determines the amount of Path 26 transfer capacity available for RA counting purposes after accounting for (1) Existing Transmission Contracts (ETCs) that serve load outside the CAISO Balancing Area[7] and (2) loop flow[8] from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North).

Both NP 26 and SP 26 load forecast, import allocation and zonal results refer to the CAISO Balancing Area only. This is done in order to be consistent with the import allocation methodology.

All resources that are counted as part of the Local Area Capacity Requirements fully count toward the Zonal Need. The local areas of San Diego, LA Basin and Big Creek/Ventura are all situated in SP26 and the remaining local areas are in NP26.

Changes compared to last year's results:

- The load forecast went up in Southern California by about 700 MW and down in Northern California by about 900 MW.
- The Import Allocations went down in Southern California by about 650 MW and down in Northern California by about 200 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2018. If there are any changes, they will be heavily influenced by the pre-existing "grandfathered contracts" and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

---

[7] The transfer capability on Path 26 must be de-rated to accommodate ETCs on Path 26 that are used to serve load outside of the CAISO Balancing Area. These particular ETCs represent physical transmission capacity that cannot be allocated to LSEs within the CAISO Balancing Area.

[8] "Loop flow" is a phenomenon common to large electric power systems like the Western Electricity Coordinating Council. Power is scheduled to flow point-to-point on a Day-ahead and Hour-ahead basis through the CAISO. However, electric grid physics prevails and the actual power flow in real-time will differ from the pre-arranged scheduled flows. Loop flow is real, physical energy and it uses part of the available transfer capability on a path. If not accommodated, loop flow will cause overloading of lines, which can jeopardize the security and reliability of the grid.

C. Summary of Results by Local Area

Each Local Capacity Area's overall requirement is determined by also achieving each sub-area requirement. Because these areas are a part of the interconnected electric system, the total for each Local Capacity Area is not simply a summation of the sub-area needs. For example, some sub-areas may overlap and therefore the same units may count for meeting the needs in both sub-areas.

1. Humboldt Area

<u>Area Definition:</u>

The transmission tie lines into the area include:

1) Bridgeville-Cottonwood 115 kV line #1
2) Humboldt-Trinity 115 kV line #1
3) Willits-Garberville 60 kV line #1
4) Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

1) Bridgeville and Low Gap are in, Cottonwood and First Glen are out
2) Humboldt is in, Trinity is out
3) Willits and Lytonville are out, Kekawaka and Garberville are in
4) Trinity is out, Ridge Cabin and Maple Creek are in

<u>Load:</u>

Total 2019 busload within the defined area: 180 MW with -5 MW of AAEE and 12 MW of losses resulting in total load + losses of 187 MW.

<u>List of physical units:</u> See Appendix A.

<u>Major new projects modeled:</u>

1. Humboldt 115/60 kV #1 and #2 transformer replacement
2. Bridgeville 115/60 kV #1 transformer replacement
3. Garberville Reactive Support

Critical Contingency Analysis Summary:

Humboldt Overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV line overlapping with an outage of the Humboldt – Humboldt Bay 115 kV line. The area limitation is the overload on the Trinity – Humboldt 115 kV line. This contingency establishes a LCR of 165 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is an outage of the Bridgeville-Cottonwood 115 kV line with one of the Humboldt Bay 115 kV units out of service. The limitation is the overload on the Humboldt–Trinity 115 kV line and establishes a LCR of 116 MW.

Effectiveness factors:

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7110 (T-138Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

Compared to 2018 the total load forecast did not change and the LCR needs decreased by 4 MW.

Humboldt Overall Requirements:

2019	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	0	202	202

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	116	0	116
Category C (Multiple)[10]	165	0	165

[9] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[10] Multiple contingencies means that the system will be able the survive the loss of a single element, and

2. North Coast / North Bay Area

Area Definition:

The transmission tie facilities coming into the North Coast/North Bay area are:

1) Cortina-Mendocino 115 kV Line
2) Cortina-Eagle Rock 115 kV Line
3) Willits-Garberville 60 kV line #1
4) Vaca Dixon-Lakeville 230 kV line #1
5) Tulucay-Vaca Dixon 230 kV line #1
6) Lakeville-Sobrante 230 kV line #1
7) Ignacio-Sobrante 230 kV line #1

The substations that delineate the North Coast/North Bay area are:

1) Cortina is out, Mendocino and Indian Valley are in
2) Cortina is out, Eagle Rock, Highlands and Homestake are in
3) Willits and Lytonville are in, Garberville and Kekawaka are out
4) Vaca Dixon is out Lakeville is in
5) Tulucay is in Vaca Dixon is out
6) Lakeville is in, Sobrante is out
7) Ignacio is in, Sobrante and Crocket are out

Load:

Total 2019 busload within the defined area: 1500 MW with -18 MW of AAEE, -56 MW of NTM-PV, and 40 MW of losses resulting in total load + losses of 1465 MW.

List of physical units: See Appendix A.

Major new projects modeled: None.

---

the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

Critical Contingency Analysis Summary:

Eagle Rock Sub-area

The most critical contingency is the outage of Cortina-Mendocino 115 kV line and Geysers #5-Geysers #3 115 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 228 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the outage of the Cortina-Mendocino 115 kV line with Geysers 11 generation unit out of service. The sub-area area limitation is thermal overloading of Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 212 MW in 2019.

Effectiveness factors:

See Appendix B - Table titled Eagle Rock.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7120 (T-151Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Fulton Sub-area

The most critical contingency is the outage of Lakeville-Fulton 230 kV line #1 and Fulton-Ignacio 230 kV line #1. The sub-area limitation is thermal overloading of Lakeville #2 60 kV line (Lakeville-Petaluma-Cotati 60 kV line). This limiting contingency establishes a LCR of 525 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

See Appendix B – Table titled Fulton.

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Tulucay 230 kV line with DEC power plant out of service. The area limitation is thermal overloading of Vaca Dixon-Lakeville 230 kV. This limiting contingency establishes a LCR of 689 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

See Appendix B – Table tilted Lakeville.

Changes compared to last year's results:

The 2019 load forecast went up by 132 MW compared to the 2018 and total LCR need went up by 55 MW mainly due to load increase.

North Coast/North Bay Overall Requirements:

2019	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	5	114	771	890

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	689	0	689
Category C (Multiple)[12]	689	0	689

[11] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[12] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

3. Sierra Area

Area Definition:

The transmission tie lines into the Sierra Area are:

1) Table Mountain-Rio Oso 230 kV line
2) Table Mountain-Palermo 230 kV line
3) Table Mt-Pease 60 kV line
4) Caribou-Palermo 115 kV line
5) Drum-Summit 115 kV line #1
6) Drum-Summit 115 kV line #2
7) Spaulding-Summit 60 kV line
8) Brighton-Bellota 230 kV line
9) Rio Oso-Lockeford 230 kV line
10) Gold Hill-Eight Mile Road 230 kV line
11) Lodi STIG-Eight Mile Road 230 kV line
12) Gold Hill-Lake 230 kV line

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out
6) Drum is in Summit is out
7) Spaulding is in Summit is out
8) Brighton is in Bellota is out
9) Rio Oso is in Lockeford is out
10) Gold Hill is in Eight Mile is out
11) Lodi STIG is in Eight Mile Road is out
12) Gold Hill is in Lake is out

Load:

Total 2019 busload within the defined area: 1768 MW with -19 MW of AAEE, -78 MW of BTM-PV and 87 MW of losses resulting in total load + losses of 1758 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Gold Hill-Missouri Flat #1 and #2 115 kV line reconductoring

<u>Critical Contingency Analysis Summary:</u>

Placerville Sub-area

No requirement due to Gold Hill-Missouri Flat #1 and #2 115 kV line reconductoring project that is expected to be in service in Q2, 2018.

Placer Sub-area

The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a LCR of 77 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 64 MW in 2019.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Pease Sub-area

The most critical contingency is the loss of the Pease 115/60 kV transformer followed by the loss of the Yuba City unit. The area limitation is thermal overloading of the Table Mountain – Pease 60 kV line. This limiting contingency establishes a LCR of 92 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo-East Nicolaus 115 kV line with Yuba City Energy Center unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 79 MW in 2019.

Effectiveness factors:

All units within this area have the same effectiveness factor.

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Atlantic 230 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Brighton 230 kV line. This limiting contingency establishes a LCR of 831 MW (includes 104 MW of deficiency) in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 507 MW in 2019.

Effectiveness factors:

See Appendix B - Table titled Rio Oso.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 (T-165Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2019 a LCR of 506 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Palermo #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2019 a LCR of 378 MW .

Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 (T-165Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

South of Palermo Sub-area

The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a LCR of 1702 MW (includes 283 MW of deficiency) in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Table Mountain-Rio Oso 230 kV line with Belden unit out of service. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line and establishes in 2019 a LCR of 1283 MW.

Effectiveness factors:

All units within the South of Palermo are needed therefore no effectiveness factor is required.

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV and Table Mountain-Palermo double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limiting contingency establishes in 2019 a LCR of 1964 MW as the minimum capacity necessary for reliable load serving capability within this area.

The units required for the South of Palermo sub-area satisfy the single contingency requirement for this sub-area.

Effectiveness factors:

See Appendix B - Table titled South of Table Mountain.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 (T-165Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

The Sierra area load forecast went down by 60 MW and the LCR need has increased by 134 MW due to impact of load and generation distribution on line flows.

Sierra Overall Requirements:

2019	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	38	1108	1004	2150

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1362	0	1362
Category C (Multiple)[14]	1964	283	2247

4. Stockton Area

Area Definition:

The transmission facilities that establish the boundary of the Tesla-Bellota Sub-area are:

1) Bellota 230/115 kV Transformer #1
2) Bellota 230/115 kV Transformer #2
3) Tesla-Tracy 115 kV Line
4) Tesla-Salado 115 kV Line
5) Tesla-Salado-Manteca 115 kV line
6) Tesla-Schulte #1 115 kV Line
7) Tesla-Schulte #2 115 kV Line

The substations that delineate the Tesla-Bellota Sub-area are:

[13] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[14] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

1) Bellota 230 kV is out Bellota 115 kV is in
2) Bellota 230 kV is out Bellota 115 kV is in
3) Tesla is out Tracy is in
4) Tesla is out Salado is in
5) Tesla is out Salado and Manteca are in
6) Tesla is out Schulte is in
7) Tesla is out Schulte is in

The transmission facilities that establish the boundary of the Lockeford Sub-area are:

1) Lockeford-Industrial 60 kV line
2) Lockeford-Lodi #1 60 kV line
3) Lockeford-Lodi #2 60 kV line
4) Lockeford-Lodi #3 60 kV line

The substations that delineate the Lockeford Sub-area are:

1) Lockeford is out Industrial is in
2) Lockeford is out Lodi is in
3) Lockeford is out Lodi is in
4) Lockeford is out Lodi is in

The transmission facilities that establish the boundary of the Weber Sub-area are:

1) Weber 230/60 kV Transformer #1
2) Weber 230/60 kV Transformer #2
3) Weber 230/60 kV Transformer #2a

The substations that delineate the Weber Sub-area are:

1) Weber 230 kV is out Weber 60 kV is in
2) Weber 230 kV is out Weber 60 kV is in
3) Weber 230 kV is out Weber 60 kV is in

Load:

Total 2019 busload within the defined area: 1204 MW with -18 MW of AAEE, -32 MW of BTM-PV, and 20 MW of losses resulting in total load + losses of 1174 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Weber-Stockton “A” #1 & #2 60 kV Reconductoring
2. Ripon 115 kV Line

<u>Critical Contingency Analysis Summary:</u>

Stockton overall

The requirement for this area is driven by the sum of requirements for the Tesla-Bellota, Lockeford and Weber Sub-areas.

Stanislaus Sub-area

The critical contingency for the Stanislaus area is the loss of Bellota-Riverbank-Melones 115 kV circuit with Stanislaus PH out of service. The area limitation is thermal overloading of the River Bank Jct.-Manteca 115 kV line. This limiting contingency establishes a local capacity need of 152 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 673 MW (includes 291 MW of deficiency) in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Schulte-Kasson-Manteca 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Tracy 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 532 MW (includes 291 MW of deficiency) in 2019.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Schulte #1 115 kV lines. The area limitation is thermal overload of the Tesla-Schulte #2 115 kV line. This limiting contingency establishes a 2019 local capacity need of 382 MW.

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-

Schulte #2 115 kV line and the loss of the GWF Tracy unit #3. The area limitation is thermal overload of the Tesla-Schulte #1 115 kV line. This single contingency establishes a local capacity need of 381 MW in 2019.

All of the resources needed to meet the Stanislaus sub-area count towards the Tesla-Bellota sub-area LCR need.

Effectiveness factors:
All units within this sub-area are needed therefore no effectiveness factor is required.

Lockeford Sub-area
The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2019 local capacity need of 83 MW (including 59 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Lockeford-Industrial 60 kV line with Lodi CT unit out of service. The area limitation is thermal overloading of the Lockeford-Lodi 60 kV line and establishes in 2019 a LCR of 29 MW (including 5 MW of deficiency).

Effectiveness factors:
All units within this sub-area are needed therefore no effectiveness factor is required.

Weber Sub-area
The critical contingency for the Weber area is the loss of Stockton A-Weber #1 & #2 60 kV lines. The area limitation is thermal overloading of the Stockton A-Weber #3 60 kV line. This limiting contingency establishes a local capacity need of 21 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Changes compared to last year's results:

Overall the Stockton area load forecast went up by 5 MW. The overall requirement for the Stockton area increased by 58 MW mainly due to increase in deficiency.

Stockton Overall Requirements:

2019	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	18	126	489	633

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	405	5	410
Category C (Multiple)[16]	427	350	777

5. Greater Bay Area

Area Definition:

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Birds Landing SW Sta 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV

---

[15] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[16] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Los Banos 500 kV
16) Moss Landing-Coburn 230 kV
17) Moss Landing-Las Aguillas 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville is out Sobrante is in
2) Ignacio is out Crocket and Sobrante are in
3) Parkway is out Moraga is in
4) Bahia is out Moraga is in
5) Lambie SW Sta is in Vaca Dixon is out
6) Peabody is out Birds Landing SW Sta is in
7) Tesla and USWP Ralph are out Kelso is in
8) Tesla and Altmont Midway are out Delta Switching Yard is in
9) Tesla and Tres Vaqueros are out Pittsburg is in
10) Tesla and Flowind are out Pittsburg is in
11) Tesla is out Newark is in
12) Tesla is out Newark and Patterson Pass are in
13) Tesla is out Ravenswood is in
14) Tesla is out Metcalf is in
15) Los Banos is out Moss Landing is in
16) Coburn is out Moss Landing is in
17) Las Aguillas is out Moss Landing is in
18) Oakdale TID is out Newark is in
19) Oakdale TID is out Newark is in

Load:

Total 2019 bus load within the defined area is 10,160 MW with -137 MW of AAEE, -230 MW of Behind the meter DG, 217 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 10,274 MW. The expanded Bay Area also includes Moss Landing area load according to the Area Definition as delineated above.

List of physical units: See Appendix A.

Major new projects modeled:

1. Metcalf-Evergreen 115 kV Line Reconductoring

2. South of San Mateo Capacity Increase (revised scope)
3. San Jose-Trimble 115 kV Line Limiting Facility Upgrade
4. Moss Landing–Panoche 230 kV Path Upgrade
5. San Jose-Trimble 115 kV Series Reactor

<u>Critical Contingency Analysis Summary:</u>

Oakland Sub-area

The most critical contingency is an outage of the D-L and C-X #3 115 kV cables. The area limitation is thermal overloading of the C-X #2115 kV cable. This limiting contingency establishes a LCR of 20 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Llagas Sub-area

The most critical contingency is an outage Metcalf D-Morgan Hill 115 kV Line with one of the Gilroy Peaker off-line. The area limitation is thermal overloading of the Morgan Hill-Llagas 115 kV line. As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 77 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

San Jose Sub-area

The most critical contingency is an outage of Newark-Los Esteros 230 kV Line overlapped with Metcalf-Los Esteros 230 kV line. The area limitation is thermal overloading of the Newark-NRS 115 kV line. This limiting contingency establishes a LCR of 177 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

See Appendix B – Table titled San Jose.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 (T-133Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

South Bay-Moss Landing Sub-area

The most critical contingency is an outage of the Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV. The area limitation is thermal overloading of the Las Aguillas-Moss Landing 230 kV. This limiting contingency establishes a LCR of 1653 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Resources in San Jose and Llagas sub-areas are also included in this sub-area.

Effectiveness factors:

See Appendix B – Table titled South Bay-Moss Landing.

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with the Gateway off line. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 1067 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 (T-133Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Ames/Pittsburg/Oakland Sub-areas Combined

The one critical contingency in NCNB and two most critical contingencies in Ames/Pittsburg/Oakland listed below together establish a local capacity need of 2430 MW in 2019 as follows: 689 MW in NCNB and 1741 MW in the Ames/Pittsburg/Oakland as the minimum capacity necessary for reliable load serving capability within these sub-areas.

The most critical contingencies in the Bay Area are:
1) an outage of DCTL Newark-Ravenswood & Tesla-Ravenswood 230 kV with limitation of thermal overloading of Ames-Ravenswood #1 115 kV line. And
2) an overlapping outage of Moraga-Sobrante & Moraga-Claremont #1 115 kV lines with limitation of thermal overloading of Moraga-Claremont #2 115 kV line.

The most critical contingency in North Coast/North Bay area is an outage of Vaca Dixon-Tulucay 230 kV line with Delta Energy Center power plant out of service. The area limitation is thermal overloading of Vaca Dixon-Lakeville 230 kV line.

Effectiveness factors:
See Appendix B – Table titled Ames/Pittsburg/Oakland. For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 (T-133Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Bay Area overall
The most critical need is the aggregate of sub-area requirements. This establishes a LCR of 4461 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is an outage of the Tesla-Metcalf 500 kV line with Delta Energy Center out of service. The sub-area area limitation is reactive margin within the Bay Area. This limiting contingency establishes a LCR of 3670 MW in 2019.

Effectiveness factors:
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 (T-133Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

From 2018 the load forecast is up by 27 MW compared with the physically defined Bay Area. The LCR has decreased by 699 MW due to new transmission projects.

Bay Area Overall Requirements:

2019	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Wind (MW)	Battery (MW)	Max. Qualifying Capacity (MW)
Available generation	246	382	6124	320	4	7076

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	3670	0	3670
Category C (Multiple)[18]	4461	0	4461

6. Greater Fresno Area

Area Definition:

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Mustang #1 230 kV Line
2) Gates- Mustang #2 230 kV Line
3) Gates #1 230/70 kV Transformer Bank
4) Los Banos #3 230/70 kV Transformer Bank
5) Los Banos #4 230/70 kV Transformer Bank
6) Panoche-Tranquility #1 230 kV Line
7) Panoche- Tranquility #2 230 kV Line
8) Panoche #1 230/115 kV Transformer
9) Panoche #2 230/115 kV Transformer
10) Warnerville-Wilson 230 kV Line
11) Wilson-Melones 230 kV Line
12) Smyrna-Corcoran 115kV Line
13) Coalinga #1-San Miguel 70 kV Line

[17] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[18] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

The substations that delineate the Greater Fresno area are:

1) Gates is out Mustang is in
2) Gates is out Mustang is in
3) Gates 230 kV is out Gates 70 kV is in
4) Los Banos 230 kV is out Los Banos 70 kV is in
5) Los Banos 230 kV is out Los Banos 70 kV is in
6) Panoche is out Helm is in
7) Panoche is out Mc Mullin is in
8) Panoche 115 kV is in Panoche 230 kV is out
9) Panoche 115 kV is in Panoche 230 kV is out
10) Warnerville is out Wilson is in
11) Wilson is in Melones is out
12) Quebec SP is out Corcoran is in
13) Coalinga is in San Miguel is out

Load:

2019 total busload within the defined area is 3165 MW with -33 MW of AAEE, 95 MW of losses and -158 MW DG resulting in a total (load plus losses) of 3070 MW.

List of physical units: See Appendix A.

***Major new projects modeled*:**

1. Leemore 70kV Disconnect Switches Replacement (Jun 2018)
2. Los Banos-Livingston Jct-Canal 70kV Switch Replacement (Jun 2018)
3. Kearney-Caruthers 70kV reconductoring (2019)
4. Borden 230kV Voltage Support (2019)
5. Kearney-Herndon 230 kV Line Reconductor (2019)

Critical Contingency Analysis Summary:

Hanford Sub-area

The most critical contingency for the Hanford sub-area is the loss of the Gates-Mustang #1 and #2 230 kV lines, which would thermally overload the McCall-Kingsburg #1 115 kV line. This limiting contingency establishes a local capacity need of 56 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Coalinga Sub-area

The most critical contingency for the Coalinga sub-area is the loss of the Gates #5 230/70 kV transformer followed by the Panoche-Schindler #1 and #2 115 kV double circuit tower line, which could cause voltage instability in the pocket. This limiting contingency establishes a local capacity need of 18 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Borden Sub-area

The most critical contingency for the Borden sub-area is the loss of the Borden #4 230/70 kV transformer followed by the Friant-Coppermine 70 kV line, which could cause overload on the Borden #1 230/70 kV transformer. This limiting contingency establishes a local capacity need of 1 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Reedley Sub-area

The most critical contingency for the Reedley sub-area is the loss of the McCall-Reedley (McCall-Wahtoke) 115 kV line followed by the Sanger-Reedley 115 kV line, which could thermally overload the Kings River-Sanger-Reedley (Sanger-Rainbow Tap) 115 kV line. This limiting contingency establishes a local capacity need of 5 MW in 2019 including 1 MW of deficiency as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

There is no single critical contingency in this sub-area.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

Herndon Sub-area

The most critical contingency is the loss of Herndon-Woodward 115 kV line and Herndon-Barton 115 kV lines. This contingency could thermally overload the Herndon- Manchester 115 kV line. This limiting contingency established an LCR of 792 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The second most critical contingency is the loss of Herndon-Barton 115 kV line with Balch 1 generating unit out of service. This contingency would thermally overload the Herndon-Manchester 115 kV line and establishes an LCR of 267 MW.

Effectiveness factors:

See Appendix B - Table titled Herndon.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 (T-129) posted at: http://www.caiso.com/Documents/2210Z.pdf

Overall (Wilson) Sub-area

The most critical contingency is the loss of the Common mode (DCTL) Borden-Gregg #1 and #2 230 kV lines. This contingency would thermally overload the Panoche-Oro Loma 115 kV line. This limiting contingency establishes a LCR of 1670 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this area.

The second most critical contingency is the Loss of Panoche-Mendota 115 kV line followed by the loss of one Helms Unit. This contingency would thermally overload the Panoche-Oro Loma 115 kV line and establishes an LCR of 1406 MW in 2019.

Effectiveness factors:

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 (T-129) posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

From 2018 the load forecast has decreased by 220 MW and the LCR by 410 MW.

Fresno Area Overall Requirements:

2019	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	28	312	3177	3517

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	1406	0	1406
Category C (Multiple) [20]	1670	1	1671

7. Kern Area

Area Definition:

The transmission facilities coming into the Kern PP sub-area are:

1) Midway-Kern PP #1 230 kV Line
2) Midway-Kern PP #3 230 kV Line
3) Midway-Kern PP #4 230 kV Line
4) Famoso-Lerdo 115 kV Line (Normal Open)
5) Wasco-Famoso 70 kV Line (Normal Open)
6) Copus-Old River 70 kV Line (Normal Open)
7) Copus-Old River 70 kV Line (Normal Open)

---

[19] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[20] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

8) Weedpatch CB 32 70 kV (Normal Open)
9) Wheeler Ridge-Lamont 115 kV Line (Normal Open)

The substations that delineate the Kern-PP sub-area are:

1) Midway 230 kV is out Bakersfield and Stockdale 230 kV are in
2) Midway 230 kV is out Kern and Stockdale 230 kV are in
3) Midway 230 kV is out Kern PP 230 kV is in
4) Famoso 115 kV is out Cawelo 115 kV is in
5) Wasco 70 kV is out Mc Farland 70 kV is in
6) Copus 70 kV is out, South Kern Solar 70 kV is in
7) Lakeview 70 kV is out, San Emidio Junction 70 kV is in
8) Weedpatch 70 kV is out, Wellfield 70 kV is in
9) Wheeler Ridge 115 kV is out, Adobe Solar 115 kV is in

Load:

2019 total busload within the defined area is 1157 MW with -18 MW of AAEE, 9 MW of losses and -60 MW DG resulting in a total (load plus losses) of 1088 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Upgrade terminal equipment on Kern PP #4 230/115kV transformer

Critical Contingency Analysis Summary:

Westpark Sub-area

The most critical contingency is PSE-Bear and Kern-Westpark # 1 or # 2 resulting in thermal overload of the remaining Kern-Westpark # 1 or # 2. This limiting contingency establishes a LCR of 51 MW (including 6 MW of deficiency) in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Kern Oil Sub-area

The most critical contingency is the Kern PP-Live Oak 115 kV Line and Kern PP-7th Standard 115 kV Line resulting in the thermal overload of the Kern PP-Magunden-Witco 115 kV Line (Kern PP-Kern Water section). This limiting contingency establishes a LCR of 116 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Kern PP -7th Standard 115 kV line with Mount Poso unit out of service. The area limitation is thermal overloading of the Kern PP-Magunden-Witco 115 kV line (Kern PP-Kern Water section) and establishes in 2019 a LCR of 103 MW.

Effectiveness factors:
All units within this sub-area have the same effectiveness factor.

South Kern PP Sub-area Overall
The most critical contingency is the outage of the Midway-Kern #3 and #4 230 kV lines, which thermally overloads the Midway-Kern #1 230 kV line (Midway to Stockdale J1 section). This limiting contingency establishes a LCR of 472 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Midway-Kern PP # 3 230 kV line with High Sierra unit out of service. The area limitation is thermal overloading of the Midway-Kern PP # 1 230 kV line and establishes in 2019 a LCR of 106 MW.

Effectiveness factors:
All units within this sub-area have the same effectiveness factor.
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 (New) posted at: http://www.caiso.com/Documents/2210Z.pdf

<u>Changes compared to last year's results:</u>
Kern area load forecast has gone up by 221 MW and the LCR requirement has increased by 25 MW. The upward shift in load is due to definition change (with no resource impact) and the upward shift in requirement is attributed to change in the overloaded line section for the same worst contingency.

Kern Area Overall Requirements:

2019	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	13	462	475

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [21]	148	6	154
Category C (Multiple) [22]	472	6	478

8. LA Basin Area

Area Definition:

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre – Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #2 & #3 500 kV Lines
4) Lugo – Rancho Vista #1 500 kV line
5) Sylmar - Eagle Rock 230 kV Line
6) Sylmar - Gould 230 kV Line
7) Vincent – Mira Loma 500 kV Line
8) Vincent - Mesa Cal 230 kV Line
9) Vincent - Rio Hondo #1 & #2 230 kV Lines
10) Eagle Rock - Pardee 230 kV Line
11) Devers - RedBluff #1 and #2 500 kV Lines
12) Mirage – Coachela Valley 230 kV Line
13) Mirage - Ramon 230 kV Line
14) Mirage - Julian Hinds 230 kV Line

These substations form the boundary surrounding the LA Basin area:

1) San Onofre is in San Luis Rey is out
2) San Onofre is in Talega is out
3) Mira Loma is in Lugo is out

[21] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[22] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

4) Rancho Vista is in Lugo is out
5) Eagle Rock is in Sylmar is out
6) Gould is in Sylmar is out
7) Mira Loma is in Vincent is out
8) Mesa Cal is in Vincent is out
9) Rio Hondo is in Vincent is out
10) Eagle Rock is in Pardee is out
11) Devers is in RedBluff is out
12) Mirage is in Coachela Valley is out
13) Mirage is in Ramon is out
14) Mirage is in Julian Hinds is out

Load:

The total 2019 1-in-10 heat wave peak load modeled within the electrically defined area[23] includes 18,960 MW net managed peak load[24] with 22 MW pump load and 284 MW of losses resulting in total net load + losses + pumps of 19,266 MW. The electrically defined LA Basin LCR area does not include Saugus substation load, which is 797 MW. When this load and associated losses (12 MW) is added to the electrically defined LA Basin load and losses, the total geographically-defined LA Basin load is 20,075 MW, which correlates with the CEC's Mid Demand Baseline with Low AAEE/AAPV Savings for 2019.

List of physical units: See Appendix A.

Major new projects modeled:

1. Santiago synchronous condensers (3x81/-35 MVAR units)
2. Implementation of 256 MW[25] of long-term procurement plan (LTPP) preferred resources for the western LA Basin subarea (part of the CPUC LTPP Track 4 approved Power Purchase Agreement)

---

[23] The electrically defined area load is the LA Basin load minus Saugus substation load. When Saugus load (located in the LA County) is added to the electrically defined area load, its resulting total demand will match with the CEC demand forecast for the LA Basin planning area.
[24] The CEC included peak shift impact to the demand forecast in the 2017 Integrated Energy Policy Report (IEPR) demand forecast.
[25] Information provided by Southern California Edison Company as part of data request for input assumptions to the 2019 LCR study

3. San Luis Rey (2-225 MVAR), San Onofre (1-240 MVAR), Miguel (2-225 MVAR) and Santiago (3-81 MVAR) synchronous condensers
4. Imperial Valley Phase Shifting Transformers (230/230kV 2x400 MVA)
5. Encina generating facility retirement
6. Carlsbad Energy Center (500 MW) in service
7. Sycamore – Penasquitos 230 kV transmission line
8. Implementation of 77 MW of battery energy storage projects[26] in the SDG&E service area

Critical Contingency Analysis Summary:

El Nido sub-area:

The most critical contingency for the El Nido sub-area is the loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which could cause voltage collapse. This limiting contingency establishes an LCR of 231 MW (including 12.5 MW of existing 20-minute demand response and 23.7 MW of LTPP preferred resources) in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units have the same effectiveness factor.

Western LA Basin Sub-Area:

The most critical contingency for the Western LA Basin sub-area is the loss of Serrano – Villa Park #2 230 kV line followed by the loss of the Serrano – Lewis #1 or #2 230 kV line or vice versa, which could result in thermal overload of the remaining Serrano – Villa Park 230 kV line. This limiting contingency establishes an LCR of 3,993 MW (including 162 MW of existing 20-minute demand response and 248 MW of LTPP preferred resources) in 2019 as the resource capacity necessary for reliable load serving capability within this sub-area.

[26] Information provided by SDG&E

Effectiveness factors:

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7630 (G-219Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

There are other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area and have less LCR need. As such, anyone of them (combination of contingencies) could become binding for any given set of procured resources. As a result, effectiveness factors may not be the best indicator towards informed procurement.

Eastern LA Basin Sub-area:

The most critical contingency for the eastern LA Basin is an outage of the Serrano – Valley 500 kV line, followed by the Devers – Red Bluff #1 and #2 500 kV lines, which could cause post-transient voltage instability concern. This limiting contingency establishes an LCR of 2,956 MW (including 159 MW of existing 20-minute demand response) in 2019 as the resource capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units have the same effectiveness factor.

West of Devers Sub-area:

Satisfied by the need in the larger Eastern LA Basin sub-area.

Valley Sub-area:

Satisfied by the need in the larger Eastern LA Basin sub-area.

Valley-Devers Sub-Area:

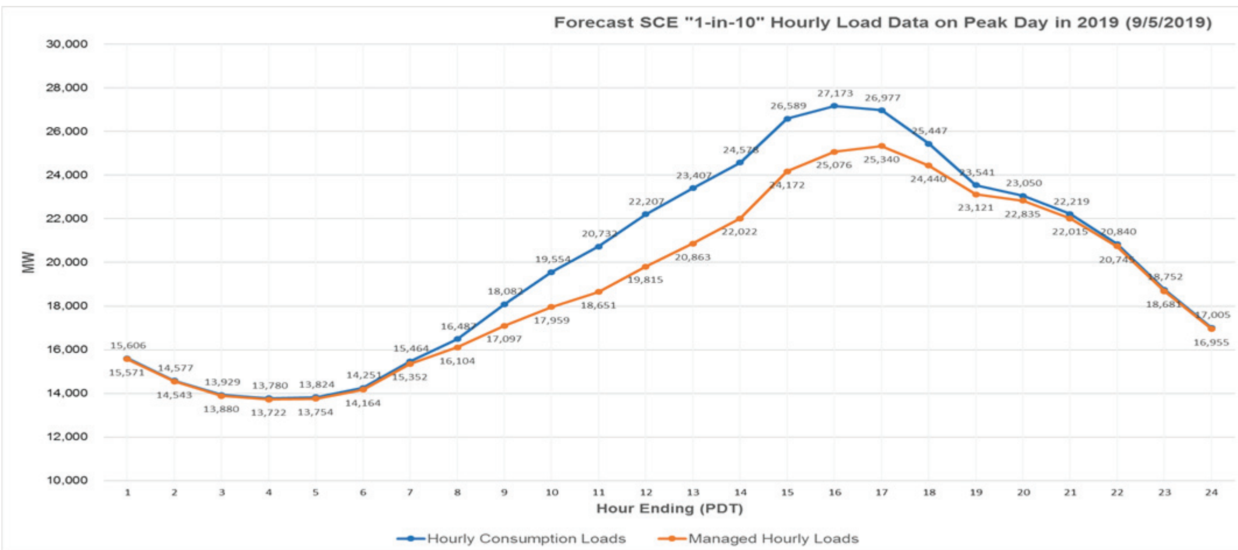
Satisfied by the need in the larger Eastern LA Basin sub-area.

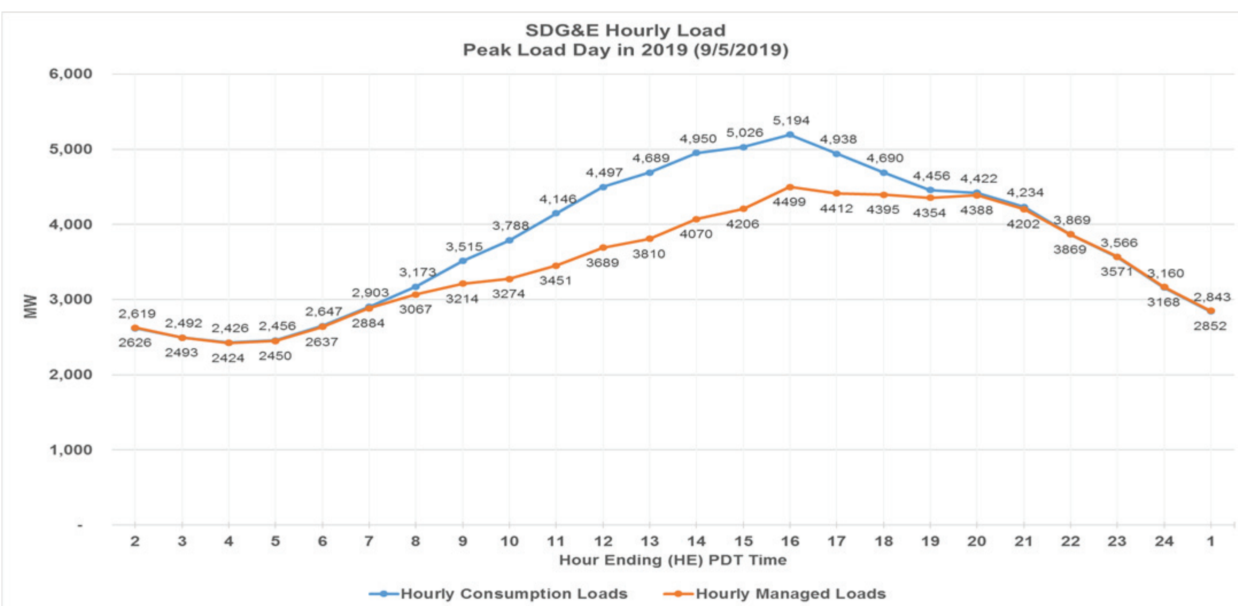
Overall LA Basin Area and San Diego-Imperial Valley Area Combined:

The LCR needs of the LA Basin area and San Diego-Imperial Valley area have been considered through a coordinated study process to ensure that the resource needs for each LCR area not only satisfy its own area reliability need but also provide support to the other area if needed. With the retirement of the San Onofre Nuclear Generating Station, and the impending retirement of other once-through cooled generation in the LA Basin and San Diego areas, the two areas are electrically interdependent on each other. Resource needs in one area are dependent on the amount of resources that are dispatched for the adjacent area and vice versa. The SDG&E system, being the southernmost electrical area in the ISO's southern system and smaller of the overall LA Basin-San Diego-Imperial Valley area, is evaluated first for its LCR needs. The LCR needs for the LA Basin and its sub-areas are then evaluated after the initial determination of the LCR needs for the overall San Diego-Imperial Valley area. The LCR needs in the overall San Diego-Imperial Valley area are then re-checked to ensure that the initial determination is still adequate. This iterative process is needed due to the interaction of resources on the LCR needs in the LA Basin-San Diego-Imperial Valley area. With this process, the LCR needs for the respective areas are coordinated within the overall LA Basin-San Diego-Imperial Valley area. *It is important to note that the San Diego subarea is a part or subset of the overall San Diego-Imperial Valley area.* The total LCR needs for the combined LA Basin-San Diego-Imperial Valley area are the sum of the LCR needs for the LA Basin and the San Diego-Imperial Valley area.

As part of the load assumptions for the 2019 LCR study, the ISO utilized the 1-in-2 hourly load forecast from the California Energy Commission (CEC) and adjusted to the 1-in-10 demand forecast for the peak day for 2019 timeframe utilizing the multiplier from the CEC to determine the percentage for scaling the loads for SDG&E and SCE for simultaneous peak at the time of SCE and SDG&E peak loads, respectively. Two study cases were developed: one with SCE peak load and corresponding SDG&E simultaneous load at SCE peak; the other had SDG&E peak load with corresponding SCE simultaneous load. This is to capture better load models between the two areas of

SCE and SDG&E at each other's peak demand. In previous year's LCR study, the ISO modeled both the LA Basin and SDG&E at their peak demands simultaneously based on historical load data that showed loads in these two areas that peaked at the same time. The new approach is based on the forecast of hourly loads in the future from the CEC. The following two diagrams illustrate the hourly consumption loads and the managed loads for SCE and SDG&E on the CEC's forecast peak day for these two areas on September 5, 2019. The following table illustrates the estimated derates for either SCE or SDG&E loads at the time of SDG&E or SCE peak demand, respectively.





Year	SCE peak demand			SDG&E @ SCE peak demand			SDG&E peak demand			SCE @ SDG&E peak demand		
	Date/time (PDT)*	Hourly Managed Peak Demand (MW) from hourly plot	LSE/BA Table peak demand forecast (MW)**	Date/time (PDT)*	Hourly Managed Demand (MW) from hourly plot	% of SDG&E peak demand at SCE peak	Date/time (PDT)*	Hourly Managed Peak Demand (MW) from hourly plot (MW)	LSE/BA Table peak demand forecast (MW)**	Date/time (PDT)*	Hourly Managed Demand from hourly plot (MW)	% of SCE peak at SDG&E peak demand
2019	9/5/2019 17:00 hr.	25340	25410	9/2/2019 17:00 hr.	4412	98.07%	9/5/2019 16:00 hr.	4499	4415	9/5/2019 16:00 hr.	25076	98.96%

Notes:

*All hour expressed in PDT hour ending (HE)

**Peak demand from the CEC posted 2017 CED Revised Forecast for LSE/BA Table for Mid Demand Level (1-in-10) with Low AAEE and AAPV

The following is the discussion of the LCR needs for each of these respective areas:

1. *Overall San Diego-Imperial Valley Area:*

The most critical contingency resulting in thermal loading concerns for the overall San Diego-Imperial Valley area is the G-1/N-1 (Category B) overlapping outage that involves the loss of the TDM combined cycled power plant (593 MW), system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line or vice versa (i.e., N-1/G-1 or Category C). This overlapping contingency could thermally overload the Imperial Valley – El Centro 230 kV line (i.e., the “S” line)[27]. This contingency establishes a total local capacity need of 4,026 MW in 2019 as the resource capacity necessary for reliable load serving capability within the overall San Diego – Imperial Valley area. This amount of LCR need was achieved despite having lower net qualifying capacity value solar generation at later time of the day by utilizing 20-minute demand response and

[27] The “S” line is owned and operated by the Imperial Irrigation District (IID) that connects the IID electrical grid with the ISO BAA’s SDG&E-owned electrical grid.

LTPP LCR preferred resources in the LA Basin as well as utilizing the Imperial Valley phase shifting transformers[28] to help lowering the LCR need for the overall San Diego-Imperial Valley area.

2. Overall LA Basin Area:

The most critical contingency resulting in thermal loading concerns for the overall LA Basin is the loss of the Lugo – Victorville 500 kV line, system readjustment, followed by the loss of Sylmar – Gould 230 kV line or vice versa. This overlapping contingency could thermally overload the Eagle Rock - Gould 230 kV line. This establishes a total local capacity need of 8,116 MW (including 321 MW of 20-minute demand response as well as 248 MW of LTPP preferred resources) in the LA Basin for 2019 as the minimum resource capacity necessary for reliable load serving capability within this sub-area.

The second critical contingency for the LA Basin is the overlapping G-1 of TDM, system readjustment, followed by an N-1 outage of the Imperial Valley – North Gila 500 kV line (or vice versa). This contingency requires a local capacity need of 7,968 MW (including 321 MW of 20-minute demand response and 248 MW of LTPP preferred resources) in the overall LA Basin.

The overall local capacity need for the combined LA Basin-San Diego-Imperial Valley area is 12,142 MW for 2019 as follows: 8,116 MW in the overall LA Basin and 4,026 MW in the overall San Diego-Imperial Valley area as the minimum capacity necessary for reliable load serving capability within these areas. The most limiting constraint for this overall combined LA Basin-San Diego-Imperial Valley area is the thermal loading concerns on the Eagle Rock – Gould 230 kV line under an N-1-1 overlapping contingency. This is closely followed by the limiting constraint on the “S” line between IID and SDG&E under an overlapping G-1/N-1 contingency or vice versa.

---

[28] The flow through the Imperial Valley phase shifting transformers is minimized as part of system adjustment to prepare for the next contingency. Other system readjustment includes dispatch of required resources.

Effectiveness factors:

See Appendix B - Table titled LA Basin.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7570 (T-144Z), 7580 (T-139Z), 7590 (T-137Z, 6750) and 7680 (T-130Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

Compared with 2018, the load forecast has gone up by 800 MW and the LCR need has increased by 591 MW, primarily due to higher demand forecast.

LA Basin Overall Requirements:

2019	QF (MW)	Muni (MW)	Wind (MW)	Market (MW)	Preferred Res. (MW)	20 Min. DR (MW)	Mothball (MW)	Max. Qualifying Capacity (MW)
Available generation	279	1164	124	7955	248	321	435	10,866

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[29]	7,968	0	7,968
Category C (Multiple)[30]	8,116	0	8,116

9. Big Creek/Ventura Area

Area Definition:

The transmission tie lines into the Big Creek/Ventura Area are:

1) Antelope #1 and #2 500/230 kV Transformers
2) Sylmar-Pardee #1 230 kV Line
3) Sylmar-Pardee #2 230 kV Line
4) Vincent-Pardee #1 230 kV Line

[29] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[30] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

5) Vincent-Pardee #2 230 kV Line
6) Vincent-Santa Clara 230 kV Line

These sub-stations form the boundary surrounding the Big Creek/Ventura area:

1) Antelope 500 kV is out Antelope 230 KV is in
2) Sylmar is out Pardee is in
3) Sylmar is out Pardee is in
4) Vincent is out Pardee is in
5) Vincent is out Pardee is in
6) Vincent is out Santa Clara is in

Load:

Total 2019 busload within the defined area[31] including the impact of AAEE and AAPV based on the CEC managed forecast is 4704 MW with 79 MW of losses and 379 MW of pumps resulting in total net managed load + losses + pumps of 5162 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Big Creek Corridor Rating Increase Project (ISD - 12/31/2018).

Critical Contingency Analysis Summary:

Rector Sub-area

LCR need is satisfied by the need in the larger Vestal sub-area.

Effectiveness factors:

See Appendix B - Table titled Rector.

Vestal Sub-area

The most critical contingencies for the Vestal sub-area are: the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line and the loss of

[31] The Big Creek Ventura LCA includes the Saugus Substation.

Magunden-Springville #1 230 kV line with Eastwood out of service which would thermally overload the Magunden-Springville #2 230 kV line.

These limiting contingencies establish a LCR of 621 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7500 posted at: http://www.caiso.com/Documents/2210Z.pdf

S. Clara sub-area

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 237 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

Effectiveness depends on location, reactive power capability, connection voltage and the online status of other generators in the area. Other factors being the same, generators located near Goleta are more effective than those located near Santa Clara.

Moorpark sub-area

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 433 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

In addition to location, effectiveness depends on reactive power capability, connection voltage and the online status of other generators in the area.

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2,614 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of Ormond Beach Unit #2 followed by Sylmar-Pardee #1 (or # 2) line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2,333 MW in 2019.

Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7680 (T-130Z), 7510 (T-163Z), 7550 (T-159Z) and 8610 (T-131Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

Compared with 2018 the load forecast is up by 360 MW and the LCR need has increased by 293 MW.

Big Creek Overall Requirements:

2019	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	52	372	4545	4969

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[32]	2333	0	2333
Category C (Multiple)[33]	2614	0	2614

[32] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[33] Multiple contingencies means that the system will be able the survive the loss of a single element, and

10. San Diego-Imperial Valley Area

Area Definition

The transmission tie lines forming a boundary around the Greater San Diego-Imperial Valley area include:

1) Imperial Valley – North Gila 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line
5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega #1 230 kV Line
7) San Onofre – Talega #2 230 kV Line
8) Imperial Valley – El Centro 230 kV Line
9) Imperial Valley – La Rosita 230 kV Line

The substations that delineate the Greater San Diego-Imperial Valley area are:

1) Imperial Valley is in North Gila is out
2) Otay Mesa is in Tijuana is out
3) San Onofre is out San Luis Rey is in
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out Talega is in
7) San Onofre is out Talega is in
8) Imperial Valley is in El Centro is out
9) Imperial Valley is in La Rosita is out

Load:

The CEC-adopted demand forecast for 2019 from the 2018-2030 Mid Demand Baseline, Low AAEE and AAPV savings for 1-in-10 heat wave forecast is 4,415 MW. The total managed peak demand including 117 MW losses modeled in the study is 4,412 MW.

---

the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

List of physical units: See Appendix A.

Major new projects modeled:

1. Ocean Ranch 69 kV substation
2. Mesa Height TL600 Loop-in
3. Re-conductor of Mission-Mesa Heights 69 kV
4. Re-conductor of Kearny-Mission 69 kV line
5. TL6906 Mesa Rim rearrangement
6. Upgrade Bernardo - Rancho Carmel 69kV line
7. Re-conductor of Japanes Mesa–Basilone–Talega Tap 69 kV lines
8. 2nd Miguel–Bay Boulevard 230 kV line
9. Sycamore–Penasquitos 230kV line
10. 2nd Mission 230/69 kV bank
11. Suncrest SVC project
12. By-passing 500 kV series capacitor banks on SWPL and SPL
13. Encina generation retirement
14. Carlsbad Energy Center (5x100 MW)
15. Storage projects at Melrose (20 MW)
16. Battery energy storage projects (77 MW)

Critical Contingency Analysis Summary:

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon Energy Center unit followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632) or vice versa, which could thermally overload the El Cajon – Los Coches 69 kV line (TL631). This limiting contingency establishes a LCR of 88 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Mission Sub-area

The LCR need for the Mission sub-area is eliminated with the completion of the T600 Loop-in to Mesa Heights 69 kV and TL676 Mission – Mesa Heights 69 kV reconductor projects.

Esco Sub-area

The LCR need for the Esco sub-area will be eliminated with the addition of the Sycamore-Penasquitos 230 kV project.

Pala Sub-area

The most critical contingency for the Pala sub-area is the loss of Pendleton – San Luis Rey 69 kV line (TL6912) followed by the loss of Lilac - Pala 69kV line (TL6932) which could thermally overload the Melrose – Morro Hill Tap 69 kV line (TL694). This limiting contingency establishes a LCR of 10 MW in 2019 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All the units within this sub-area have the same effectiveness factor.

Border Sub-area

The most critical contingency for the Border sub-area is the loss of Bay Boulevard – Otay 69kV line #1 (TL645) followed by Bay Boulevard - Otay 69kV line #2 (TL646), which could overload the Imperial Beach – Bay Boulevard 69 kV line (TL647). This limiting contingency establishes a local capacity need of 100 MW in 2019 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

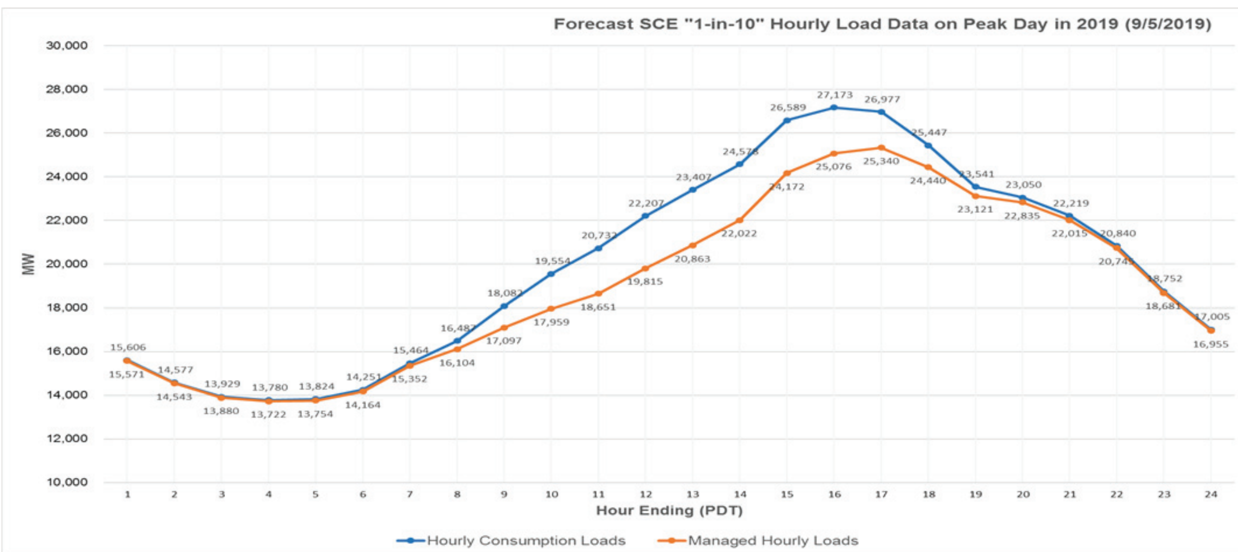
Miramar Sub-area

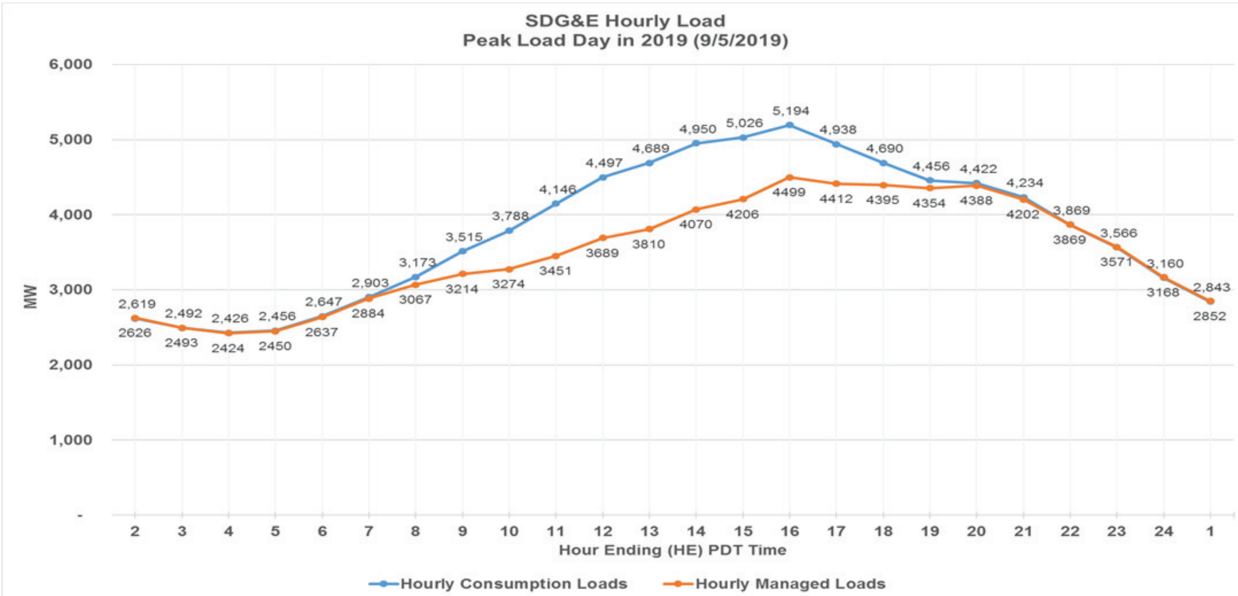
The LCR need for the Miramar sub-area is eliminated with the addition of the Sycamore-Penasquitos 230 kV and second Miguel – Bay Boulevard 230 kV line projects.

Overall LA Basin Area and San Diego-Imperial Valley Area Combined:

The LCR needs of the LA Basin area and San Diego-Imperial Valley area have been considered through a coordinated study process to ensure that the resource needs for each LCR area not only satisfy its own area reliability need but also provide support to the other area if needed. With the retirement of the San Onofre Nuclear Generating Station, and the impending retirement of other once-through cooled generation in the LA Basin and San Diego areas, the two areas are electrically interdependent on each other. Resource needs in one area are dependent on the amount of resources that are dispatched for the adjacent area and vice versa. The SDG&E system, being the southernmost electrical area in the ISO’s southern system and smaller of the overall LA Basin-San Diego-Imperial Valley area, is evaluated first for its LCR needs. The LCR needs for the LA Basin and its subareas are then evaluated after the initial determination of the LCR needs for the overall San Diego-Imperial Valley area. The LCR needs in the overall San Diego-Imperial Valley area are then re-checked to ensure that the initial determination is still adequate. This iterative process is needed due to the interaction of resources on the LCR needs in the LA Basin-San Diego-Imperial Valley area. With this process, the LCR needs for the respective areas are coordinated within the overall LA Basin-San Diego-Imperial Valley area. *It is important to note that the San Diego subarea is a part or subset of the overall San Diego-Imperial Valley area.* The total LCR needs for the combined LA Basin-San Diego-Imperial Valley area are the sum of the LCR needs for the LA Basin and the San Diego-Imperial Valley area.

As part of the load assumptions for the 2019 LCR study, the ISO utilized the 1-in-2 hourly load forecast from the California Energy Commission (CEC) and adjusted to the 1-in-10 demand forecast for the peak day for 2019 timeframe utilizing the multiplier from the CEC to determine the percentage for scaling the loads for SDG&E and SCE for simultaneous peak at the time of SCE and SDG&E peak loads, respectively. Two study cases were developed: one with SCE peak load and corresponding SDG&E simultaneous load at SCE peak; the other had SDG&E peak load with corresponding SCE simultaneous load. This is to capture better load models between the two areas of SCE and SDG&E at each other's peak demand. In previous year's LCR study, the ISO modeled both the LA Basin and SDG&E at their peak demands simultaneously based on historical load data that showed loads in these two areas that peaked at the same time. The new approach is based on the forecast of hourly loads in the future from the CEC. The following two diagrams illustrate the hourly consumption loads and the managed loads for SCE and SDG&E on the CEC's forecast peak day for these two areas on September 5, 2019. The following table illustrates the estimated derates for either SCE or SDG&E loads at the time of SDG&E or SCE peak demand, respectively.





Year	SCE peak demand			SDG&E @ SCE peak demand			SDG&E peak demand			SCE @ SDG&E peak demand		
	Date/time (PDT)*	Hourly Managed Peak Demand (MW) from hourly plot	LSE/BA Table peak demand forecast (MW)**	Date/time (PDT)*	Hourly Managed Demand (MW) from hourly plot	% of SDG&E peak demand at SCE peak	Date/time (PDT)*	Hourly Managed Peak Demand (MW) from hourly plot (MW)	LSE/BA Table peak demand forecast (MW)**	Date/time (PDT)*	Hourly Managed Demand from hourly plot (MW)	% of SCE peak at SDG&E peak demand
2019	9/5/2019 17:00 hr.	25340	25410	9/2/2019 17:00 hr.	4412	98.07%	9/5/2019 16:00 hr.	4499	4415	9/5/2019 16:00 hr.	25076	98.96%

Notes:

*All hour expressed in PDT hour ending (HE)

**Peak demand from the CEC posted 2017 CED Revised Forecast for LSE/BA Table for Mid Demand Level (1-in-10) with Low AAEE and AAPV

The following is the discussion of the LCR needs for the San Diego sub-area and the overall San Diego-Imperial Valley area (please see the section under LA Basin for the overall LA Basin LCR needs):

1. Overall San Diego-Imperial Valley Area:

The most critical contingency resulting in thermal loading concerns for the overall San Diego-Imperial Valley area is the G-1/N-1 (Category B) overlapping outage that involves the loss of the TDM combined cycled power plant (593 MW), system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line or vice versa (Category C). This overlapping contingency could thermally overload the Imperial Valley – El Centro 230 kV line (i.e., the “S” line) . This contingency establishes a local capacity need for of 4,026 MW in 2019 as the resource capacity necessary for reliable load serving capability within the overall San Diego – Imperial Valley area. This amount of LCR need was achieved despite having lower net qualifying capacity value solar generation at later time of the day by utilizing 20-minute demand response and LTPP LCR preferred resources in the LA Basin as well as utilizing the Imperial Valley phase shifting transformers[34] to help lowering the LCR need for the overall San Diego-Imperial Valley area.

Effectiveness factors:

See Appendix B - Table titled San Diego.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7820 (T-132Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

2. San Diego Sub-area:

The San Diego sub-area is part of the overall San Diego-Imperial Valley LCR area. The LCR need for the San Diego sub-area can either be caused by the larger need for the overall San Diego-Imperial Valley area (as discussed in item #1 above), or be caused by other outages that exclusively affect the San Diego sub-area only. The ultimate San Diego sub-area LCR need will be determined by the larger requirement of these analyses.

[34] The flow through the Imperial Valley phase shifting transformers is minimized as part of system adjustment to prepare for the next contingency. Other system readjustment includes dispatch of required resources.

For the outages that exclusively affect the San Diego sub-area only, it is the overlapping N-1-1 of the ECO-Miguel 500 kV line, system readjustment, followed by the outage of one of the Sycamore – Suncrest 230 kV lines. The limiting constraint is the thermal loading concern on the remaining Sycamore – Suncrest 230 kV line, causing a local capacity need of 2,417 MW in 2019 for the San Diego sub-area. The thermal loading constraint on the Sycamore-Suncrest 230 kV line is mitigated by using a combination of the Remedial Action Scheme (RAS) for generation tripping in the Imperial Valley for this outage, as well as utilization of the Imperial Valley phase-shifting transformers to provide a backup source to San Diego with the overlapping outage on the 500 kV line and 230 kV line as mentioned above.

The overall local capacity need for the combined LA Basin-San Diego-Imperial Valley area is 12,142 MW for 2019 as follows: 8,116 MW in the overall LA Basin and 4,026 MW in the overall San Diego-Imperial Valley area as the minimum capacity necessary for reliable load serving capability within these areas. The most limiting constraint for this overall combined LA Basin-San Diego-Imperial Valley area is the thermal loading concerns on the Eagle Rock – Gould 230 kV line under an N-1-1 overlapping contingency. This is closely followed by the limiting constraint on the "S" line between IID and SDG&E under an overlapping G-1/N-1 contingency or vice versa.

Net Qualifying Capacity at time of net peak demand[35]

The expectation of the Resource Adequacy (RA) program is to provide resources "when needed and where needed" in order to ensure safe and reliable operation of the grid in real time. The current Qualifying Capacity (QC) rules of Local Regulatory Agencies (LRAs) – and correspondingly Net Qualifying Capacity rules of the ISO - have not fully adjusted to changes in real time conditions and more specifically the shift of load to later hours of the day (6, 7 or 8 p.m.). This misalignment between capacity determinations and peak demands on the transmission system may result in critical local resources not being available during the most stressed demand conditions (net peak). As the ISO is mandated to maintain local and system reliability at all hours of the day during the entire

[35] In this context the net peak demand is also referred to as net peak sales, and is a reference to the load less behind the meter generation.

year, this misalignment increases the probability that other procurement, such as Capacity Procurement Mechanism (CPM) or Reliability Must Run (RMR), may be needed.

Changes compared to last year's results:

The 2019 net managed peak demand for the San Diego area is lower by about 512 MW when compared to last year study. The overall LCR needs for the San Diego-Imperial Valley has decreased by 6 MW. The main reason for the slight reduction in local capacity need for the overall San Diego – Imperial Valley LCR area despite a larger reduction in load forecast is primarily due to lower net qualifying capacity for solar generation that is located in the most effective area for mitigating the identified constraint. The lower net qualifying capacity for solar generation production was derived from the effective load carrying capability (ELCC)[36] methodology.

San Diego-Imperial Valley Area Overall Requirements:

2019	QF (MW)	Wind (MW)	Market (MW)	Battery St. (MW)	20 minute DR (MW)	Max. Qualifying Capacity (MW)
Available generation	106	187	4001	77	19	4,391

2019	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[37]	4,026	0	4,026
Category C (Multiple)[38]	4,026	0	4,026

[36] Please see "2018 Technology Factors" tab of the posted "Final Net Qualifying Capacity Report for Compliance Year 2018" at
http://www.caiso.com/Documents/NetQualifyingCapacityReport_ComplianceYear-2018.xlsx

[37] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[38] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

11. Valley Electric Area

Valley Electric Association LCR area has been eliminated on the basis of the following:

- No generation exists in this area
- No category B issues were observed in this area
- Category C and beyond –
    - No common-mode N-2 issues were observed
    - No issues were observed for category B outage followed by a common-mode N-2 outage
    - All the N-1-1 issues that were observed can either be mitigated by the existing UVLS or by an operating procedure

V. Appendix A – List of physical resources by PTO, local area and market ID

PTO	MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR AREA NAME	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
PG&E	ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.40	1	Bay Area	Oakland		MUNI
PG&E	ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	23.50	1	Bay Area	Oakland		MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	1	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	2	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	3	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	4	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	5	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	6	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	7	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	8	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	9	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	10	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	11	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	42.93	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	20.72	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	9.75	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO1	32176	SHILOH	34.5	39.75	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	39.75	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	27.16	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	26.50	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.00	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	CAYTNO_2_VASCO	30531	0162-WD	230	4.30	FW	Bay Area	Contra Costa	Aug NQC	Market
PG&E	CLRMTK_1_QF				0.00		Bay Area	Oakland	Not modeled	QF/Selfgen
PG&E	COCOPP_2_CTG1	33188	MARSHCT1	16.4	195.90	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG2	33188	MARSHCT2	16.4	195.40	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG3	33189	MARSHCT3	16.4	194.80	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG4	33189	MARSHCT4	16.4	197.55	4	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOSB_6_SOLAR				0.00		Bay Area	Contra Costa	Not modeled Energy Only	Market
PG&E	CROKET_7_UNIT	32900	CRCKTCOG	18	231.08	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen

PG&E	CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	2	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CUMBIA_1_SOLAR	33102	COLUMBIA	0.38	7.79	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33107	DEC STG1	24	269.60	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DIXNLD_1_LNDFL				1.30		Bay Area		Not modeled Aug NQC	Market
PG&E	DUANE_1_PL1X3	36865	DVRaST3	13.8	48.36	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.72	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.72	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	GATWAY_2_PL1X3	33119	GATEWAY2	18	177.51	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33120	GATEWAY3	18	177.51	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33118	GATEWAY1	18	187.47	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	69.00	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	36.00	2	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35851	GROYPKR1	13.8	47.70	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35852	GROYPKR2	13.8	47.70	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.20	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GRZZLY_1_BERKLY	32741	HILLSIDE_12	12.47	24.57	1	Bay Area	None	Aug NQC	Net Seller
PG&E	KELSO_2_UNITS	33813	MARIPCT1	13.8	49.51	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33815	MARIPCT2	13.8	49.51	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33817	MARIPCT3	13.8	49.51	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33819	MARIPCT4	13.8	49.51	4	Bay Area	Contra Costa	Aug NQC	Market

PG&E	KIRKER_7_KELCYN				3.22		Bay Area	Pittsburg	Not modeled	Market
PG&E	LAWRNC_7_SUNYVL				0.18		Bay Area	None	Not modeled Aug NQC	Market
PG&E	LECEF_1_UNITS	35854	LECEFGT1	13.8	45.97	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35855	LECEFGT2	13.8	45.97	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35856	LECEFGT3	13.8	45.97	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35857	LECEFGT4	13.8	45.97	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35858	LECEFST1	13.8	110.33	1	Bay Area	San Jose, South Bay-Moss Landing		Market
PG&E	LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	48.00	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	48.00	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	48.00	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33111	LMECCT2	18	160.07	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33112	LMECCT1	18	160.07	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33113	LMECST1	18	235.85	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	MARTIN_1_SUNSET				1.85		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	METCLF_1_QF				0.08		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	Bay Area	South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	Bay Area	South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35883	MEC STG1	18	213.13	1	Bay Area	South Bay-Moss Landing	Aug NQC	Market
PG&E	MISSIX_1_QF				0.01		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	MLPTAS_7_QFUNTS				0.04		Bay Area	San Jose, South Bay-Moss Landing	Not modeled Aug NQC	QF/Selfgen

PG&E	MOSSLD_1_QF				0.00		Bay Area		Not modeled Aug NQC	Market
PG&E	MOSSLD_2_PSP1	36221	DUKMOSS1	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36222	DUKMOSS2	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36223	DUKMOSS3	18	183.60	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36224	DUKMOSS4	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36225	DUKMOSS5	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36226	DUKMOSS6	18	183.60	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	NEWARK_1_QF				0.29		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	OAK C_1_EBMUD				1.62		Bay Area	Oakland	Not modeled Aug NQC	MUNI
PG&E	OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Bay Area	Oakland		Market
PG&E	OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Bay Area	Oakland		Market
PG&E	OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Bay Area	Oakland		Market
PG&E	OAK L_1_GTG1				0.00		Bay Area	Oakland	Not modeled Energy Only	Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	Bay Area	Ames		Market
PG&E	PALALT_7_COBUG				4.50		Bay Area	None	Not modeled	MUNI

PG&E	RICHMN_1_CHVSR2				3.48		Bay Area	None	Not modeled Aug NQC	Market
PG&E	RICHMN_1_SOLAR				0.82		Bay Area	None	Not modeled Aug NQC	Market
PG&E	RICHMN_7_BAYENV				2.00		Bay Area	None	Not modeled Aug NQC	Market
PG&E	RUSCTY_2_UNITS	35304	RUSELCT1	15	186.97	1	Bay Area	Ames	No NQC - Pmax	Market
PG&E	RUSCTY_2_UNITS	35305	RUSELCT2	15	186.97	2	Bay Area	Ames	No NQC - Pmax	Market
PG&E	RUSCTY_2_UNITS	35306	RUSELST1	15	246.06	3	Bay Area	Ames	No NQC - Pmax	Market
PG&E	RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	48.70	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	SRINTL_6_UNIT	33468	SRI INTL	9.11	0.34	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	STAUFF_1_UNIT	33139	STAUFER	9.11	0.02	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	STOILS_1_UNITS	32921	CHEVGEN1	13.8	1.22	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32922	CHEVGEN2	13.8	1.22	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32923	CHEVGEN3	13.8	0.57	3	Bay Area	Pittsburg	Aug NQC	Market
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.47	3.57	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.47	3.57	2	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.47	2.71	3	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	UNCHEM_1_UNIT	32920	UNION CH	9.11	11.07	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.25	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.25	2	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.25	3	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	USWNDR_2_SMUD	32169	SOLANOWP	21	27.08	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD2	32186	SOLANO	34.5	33.87	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_UNITS	32168	EXNCO	9.11	15.79	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWPJR_2_UNITS	39233	GRNRDG	0.69	20.72	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	10.07	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZOND_6_UNIT	35316	ZOND SYS	9.11	4.53	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	Market
PG&E	ZZ_IMHOFF_1_UNIT 1	33136	CCCSD	12.47	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_LFC 51_2_UNIT 1	35310	PPASSWND	21	0.00	1	Bay Area	None	No NQC - est. data	Wind

PG&E	ZZ_MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	Bay Area	San Jose, South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_NA	36209	SLD ENRG	12.47	0.00	1	Bay Area	South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_NA	35861	SJ-SCL W	4.3	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_SEAWST_6_LAPOS	35312	FOREBAYW	22.01	0.00	1	Bay Area	Contra Costa	No NQC - est. data	Wind
PG&E	ZZ_SHELRF_1_UNITS	33141	SHELL 1	12.47	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_SHELRF_1_UNITS	33142	SHELL 2	12.47	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_SHELRF_1_UNITS	33143	SHELL 3	12.47	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	1.90	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	0.00	2	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_ZANKER_1_UNIT 1	35861	SJ-SCL W	4.3	0.00	RN	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	30522	0354-WD	21	1.83	EW	Bay Area	Contra Costa	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	35302	NUMMI-LV	12.56	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	35859	HGST-LV	12.41	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZZZZ_COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_CONTAN_1_UNIT	36856	CCA100	13.8	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	Retired	MUNI
PG&E	ZZZZZZ_FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Bay Area	Contra Costa	Retired	Wind
PG&E	ZZZZZZ_MOSSLD_7_UNIT 6	36405	MOSSLND6	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market
PG&E	ZZZZZZ_MOSSLD_7_UNIT 7	36406	MOSSLND7	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 5	33105	PTSB 5	18	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	RT	Bay Area	Pittsburg	Retired	Market

PG&E	ZZZZZZ_PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	Bay Area	None	Retired	QF/Selfgen
PG&E	ADERA_1_SOLAR1	34319	Q644	0.48	0.00	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	ADMEST_6_SOLAR	34315	ADAMS_E	12.47	0.00	1	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	AGRICO_6_PL3N5	34608	AGRICO	13.8	22.69	3	Fresno	Wilson, Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	7.47	2	Fresno	Wilson, Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	43.13	4	Fresno	Wilson, Herndon		Market
PG&E	AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	AVENAL_6_AVSLR1				0.00		Fresno	Wilson, Coalinga	Not modeled Energy Only	Market
PG&E	AVENAL_6_AVSLR2				0.00		Fresno	Wilson, Coalinga	Not modeled Energy Only	Market
PG&E	AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	BALCHS_7_UNIT 1	34624	BALCH	13.2	33.00	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.47	4.10	1	Fresno	Wilson	Aug NQC	Market
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.47	4.10	2	Fresno	Wilson	Aug NQC	Market
PG&E	CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	4.29	1	Fresno	Wilson		Market
PG&E	CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	1.70	1	Fresno	Wilson, Coalinga	Aug NQC	QF/Selfgen
PG&E	CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.93	2	Fresno	Wilson, Coalinga	Aug NQC	QF/Selfgen
PG&E	CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	9.78	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Fresno	Wilson, Herndon		Market
PG&E	COLGA1_6_SHELLW	34654	COLNGAGN	9.11	34.70	1	Fresno	Wilson, Coalinga	Aug NQC	Net Seller
PG&E	CORCAN_1_SOLAR1				8.20		Fresno	Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
PG&E	CORCAN_1_SOLAR2				4.51		Fresno	Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market

PG&E	CRESSY_1_PARKER	34140	CRESSEY	115	0.73		Fresno	Wilson	Not modeled Aug NQC	MUNI
PG&E	CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.90	1	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	CURTIS_1_CANLCK				0.13		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	CURTIS_1_FARFLD				0.30		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	DINUBA_6_UNIT	34648	DINUBA E	13.8	3.93	1	Fresno	Wilson, Herndon, Reedley		Market
PG&E	EEKTMN_6_SOLAR1	34627	KETTLEMN	0.34	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ELCAP_1_SOLAR				0.62		Fresno	Wilson	Not Modeled Aug NQC	Market
PG&E	ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	9.40	1	Fresno	Wilson	Aug NQC	Market
PG&E	EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	90.72	1	Fresno	Wilson	Aug NQC	MUNI
PG&E	EXCLSG_1_SOLAR	34623	Q678	0.5	24.60	1	Fresno	Wilson	Aug NQC	Market
PG&E	FRESHW_1_SOLAR1	34669	Q529A	4.16	0.00	1	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	FRESHW_1_SOLAR1	34669	Q529A	0.48	0.00	2	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	5.76	2	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	3.08	3	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.81	4	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	GIFENS_6_BUGSL1				8.20		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	GIFFEN_6_SOLAR				4.10		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY	12.47	4.10	1	Fresno	Wilson	Aug NQC	Market
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY	12.47	4.10	2	Fresno	Wilson	Aug NQC	Market
PG&E	GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	49.23	1	Fresno	Wilson, Herndon, Hanford		Market
PG&E	GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	49.23	1	Fresno	Wilson, Herndon, Hanford		Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	1	Fresno	Wilson, Herndon	Aug NQC	Market

PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	2	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	HELMPG_7_UNIT 1	34600	HELMS	18	407.00	1	Fresno	Wilson	Aug NQC	Market
PG&E	HELMPG_7_UNIT 2	34602	HELMS	18	407.00	2	Fresno	Wilson	Aug NQC	Market
PG&E	HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Fresno	Wilson	Aug NQC	Market
PG&E	HENRTA_6_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	HENRTA_6_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	HENRTA_6_UNITA1	34539	GWF_GT1	13.8	49.98	1	Fresno	Wilson		Market
PG&E	HENRTA_6_UNITA2	34541	GWF_GT2	13.8	49.42	1	Fresno	Wilson		Market
PG&E	HENRTS_1_SOLAR	34617	Q581	0.38	41.00	1	Fresno	Wilson	Aug NQC	Market
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.47	4.10	1	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.47	4.10	2	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	INTTRB_6_UNIT	34342	INT.TURB	9.11	5.63	1	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	JAYNE_6_WLSLR	34639	WESTLNDS	0.48	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	KANSAS_6_SOLAR	34666	KANSASS_S	12.47	0.00	F	Fresno	Wilson	Energy Only	Market
PG&E	KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KERMAN_6_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	KERMAN_6_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	KINGCO_1_KINGBR	34642	KINGSBUR	9.11	34.50	1	Fresno	Wilson, Herndon, Hanford	Aug NQC	Net Seller
PG&E	KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KNGBRG_1_KBSLR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	KNGBRG_1_KBSLR2				0.00		Fresno	Wilson	Not modeled	Market

									Energy Only	
PG&E	KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	LEPRFD_1_KANSAS	34680	KANSAS	12.47	8.20	1	Fresno	Wilson, Hanford	Aug NQC	Market
PG&E	MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Fresno	Wilson, Herndon		Market
PG&E	MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Fresno	Wilson, Herndon		Market
PG&E	MCCALL_1_QF	34219	MCCALL 4	12.47	0.44	QF	Fresno	Wilson, Herndon	Aug NQC	QF/Selfgen
PG&E	MCSWAN_6_UNITS	34320	MCSWAIN	9.11	9.60	1	Fresno	Wilson	Aug NQC	MUNI
PG&E	MENBIO_6_RENEW1	34339	CALRENEW	12.5	2.05	1	Fresno	Wilson, Herndon	Aug NQC	Net Seller
PG&E	MENBIO_6_UNIT	34334	BIO PWR	9.11	19.24	1	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	MERCED_1_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	MERCED_1_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	MERCFL_6_UNIT	34322	MERCEDFL	9.11	3.36	1	Fresno	Wilson	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR1	34311	NORTHSTAR	0.2	24.60	1	Fresno	Wilson	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	MSTANG_2_SOLAR	34683	Q643W	0.8	12.30	1	Fresno	Wilson	Aug NQC	Market
PG&E	MSTANG_2_SOLAR3	34683	Q643W	0.8	16.40	1	Fresno	Wilson	Aug NQC	Market
PG&E	MSTANG_2_SOLAR4	34683	Q643W	0.8	12.30	1	Fresno	Wilson	Aug NQC	Market
PG&E	ONLLPP_6_UNITS	34316	ONEILPMP	9.11	0.37	1	Fresno	Wilson	Aug NQC	MUNI
PG&E	OROLOM_1_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	OROLOM_1_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	PAIGES_6_SOLAR				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	1	Fresno	Wilson, Herndon	Aug NQC	MUNI

PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	2	Fresno	Wilson, Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	3	Fresno	Wilson, Herndon	Aug NQC	MUNI
PG&E	PNCHPP_1_PL1X2	34328	STARGT1	13.8	59.96	1	Fresno	Wilson		Market
PG&E	PNCHPP_1_PL1X2	34329	STARGT2	13.8	59.96	2	Fresno	Wilson		Market
PG&E	PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Fresno	Wilson, Herndon		Market
PG&E	PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	48.00	1	Fresno	Wilson		Market
PG&E	REEDLY_6_SOLAR				0.00		Fresno	Wilson, Herndon, Reedley	Not modeled Energy Only	Market
PG&E	S_RITA_6_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.47	4.10	1	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.47	2.05	2	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.47	4.10	3	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.47	2.05	4	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	38.77	1	Fresno	Wilson	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	9.31	2	Fresno	Wilson	Aug NQC	Market
PG&E	STOREY_2_MDRCH2	34253	BORDEN D	12.47	0.21	QF	Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH3	34253	BORDEN D	12.47	0.18	QF	Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH4	34253	BORDEN D	12.47	0.27	QF	Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	STOREY_7_MDRCHW	34209	STOREY D	12.47	0.21	1	Fresno	Wilson	Aug NQC	Net Seller
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.47	4.10	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.47	4.10	2	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	TRNQL8_2_AZUSR1				0.00		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	TRNQLT_2_SOLAR	34340	Q643X	0.8	82.00	1	Fresno	Wilson	Aug NQC	Market
PG&E	ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	24.07	1	Fresno	Wilson, Herndon	Aug NQC	Market

PG&E	VEGA_6_SOLAR1	34314	VEGA	34.5	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	WAUKNA_1_SOLAR	34696	CORCORANP V_S	21	8.20	1	Fresno	Wilson, Herndon, Hanford	Aug NQC	Market
PG&E	WAUKNA_1_SOLAR2	34677	Q558	21	8.10	1	Fresno	Wilson, Herndon, Hanford	No NQC - Pmax	Market
PG&E	WFRESN_1_SOLAR				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	WHITNY_6_SOLAR				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	0.36	SJ	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WOODWR_1_HYDRO				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	WRGHTP_7_AMENGY	34207	WRIGHT D	12.47	0.03	QF	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	ZZ_BORDEN_2_QF	34253	BORDEN D	12.47	1.30	QF	Fresno	Wilson	No NQC - hist. data	Net Seller
PG&E	ZZ_BULLRD_7_SAGNE S	34213	BULLD 12	12.47	0.06	1	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	ZZ_GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	1	Fresno	Wilson, Coalinga		Market
PG&E	ZZ_JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	0.00	1	Fresno	Wilson		QF/Selfgen
PG&E	ZZ_KERKH1_7_UNIT 2	34343	KERCK1-2	6.6	8.50	2	Fresno	Wilson, Herndon	No NQC - hist. data	Market
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	1	Fresno	Wilson	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.10	2	Fresno	Wilson	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	3	Fresno	Wilson	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	34653	Q526	0.55	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market

PG&E	ZZZ_New Unit	34673	Q532	0.55	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	ZZZ_New Unit	34467	GIFFEN_DIST	12.47	4.10	1	Fresno	Wilson, Herndon	No NQC - est. data	Market
PG&E	ZZZ_New Unit	34649	Q965	0.36	5.53	1	Fresno	Wilson, Herndon	No NQC - est. data	Market
PG&E	ZZZ_New Unit	365514	Q1032G1	0.55	7.87	1	Fresno	Wilson	No NQC - est. data	Market
PG&E	ZZZ_New Unit	34644	Q679	0.55	8.20	1	Fresno	Wilson	No NQC - est. data	Market
PG&E	ZZZ_New Unit	365502	Q632BC1	0.55	8.28	1	Fresno	Wilson	No NQC - est. data	Market
PG&E	ZZZ_New Unit	34313	NORTHSTAR	0.55	61.60	1	Fresno	Wilson	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	365517	Q1032G2	0.55	7.87	2	Fresno	Wilson	No NQC - est. data	Market
PG&E	ZZZ_New Unit	365520	Q1032G3	0.55	67.49	3	Fresno	Wilson	No NQC - est. data	Market
PG&E	ZZZ_New Unit	34689	ORO LOMA_3	12.47	20.00	EW	Fresno	Wilson	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34690	CORCORAN	12.47	8.20	FW	Fresno	Wilson, Herndon, Hanford	No NQC - est. data	Market
PG&E	ZZZ_New Unit	34692	CORCORAN	12.47	12.00	FW	Fresno	Wilson, Herndon, Hanford	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34651	JACALITO-LV	0.55	1.22	RN	Fresno	Wilson	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34603	JGBSWLT	12.47	0.00	ST	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	BRDGVL_7_BAKER				0.88		Humboldt	None	Not modeled Aug NQC	Net Seller
PG&E	FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	13.58	1	Humboldt	None	Aug NQC	Net Seller
PG&E	FTSWRD_6_TRFORK				0.10		Humboldt	None	Not modeled Aug NQC	Market
PG&E	FTSWRD_7_QFUNTS				0.00		Humboldt	None	Not modeled Aug NQC	QF/Selfgen
PG&E	GRSCRK_6_BGCKWW				0.00		Humboldt	None	Not modeled	QF/Selfgen

									Energy Only	
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.30	1	Humboldt	None		Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	15.83	2	Humboldt	None		Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.67	3	Humboldt	None		Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.20	4	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.14	5	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.33	6	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.24	7	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.62	8	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.33	9	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	15.95	10	Humboldt	None		Market
PG&E	HUMBSB_1_QF				0.00		Humboldt	None	Not modeled Aug NQC	QF/Selfgen
PG&E	KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.80	1	Humboldt	None	Aug NQC	Net Seller
PG&E	LAPAC_6_UNIT	31158	LP SAMOA	12.5	0.00	1	Humboldt	None		Market
PG&E	LOWGAP_1_SUPHR				0.00		Humboldt	None	Not modeled Aug NQC	Market
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	9.31	1	Humboldt	None	Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	9.31	2	Humboldt	None	Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31153	PAC.LUMB	2.4	5.59	3	Humboldt	None	Aug NQC	Net Seller
PG&E	ZZZZZ_BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	Humboldt	None	Retired	Market
PG&E	7STDRD_1_SOLAR1	35065	7STNDRD_1	21	8.20	FW	Kern	South Kern PP, Kern Oil	Aug NQC	Market
PG&E	ADOBEE_1_SOLAR	35021	Q622B	34.5	8.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	BDGRCK_1_UNITS	35029	BADGERCK	13.8	43.00	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	BEARMT_1_UNIT	35066	PSE-BEAR	13.8	45.00	1	Kern	South Kern PP, Westpark	Aug NQC	Net Seller
PG&E	BKRFLD_2_SOLAR1				0.57		Kern	South Kern PP	Not modeled Aug NQC	Market
PG&E	DEXZEL_1_UNIT	35024	DEXEL +	13.8	17.15	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	DISCOV_1_CHEVRN	35062	DISCOVRY	13.8	3.04	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	DOUBLC_1_UNITS	35023	DOUBLE C	13.8	51.20	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KERNFT_1_UNITS	35026	KERNFRNT	9.11	51.30	1	Kern	South Kern PP	Aug NQC	Net Seller

PG&E	KRNCNY_6_UNIT	35018	KERNCNYN	11	3.42	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR1	35019	REGULUS	0.4	24.60	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR2	35092	Q744G4	0.38	8.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR3	35087	Q744G3	0.4	6.15	3	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR4	35059	Q744G2	0.4	22.06	2	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR5	35054	Q744G1	0.4	6.83	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.1	42.70	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	MAGUND_1_BKISR1				0.00		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Market
PG&E	MAGUND_1_BKSSR2				2.15		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Market
PG&E	MTNPOS_1_UNIT	35036	MT POSO	13.8	46.64	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	OLDRIV_6_BIOGAS				1.62		Kern	South Kern PP	Not modeled Aug NQC	Market
PG&E	OLDRV1_6_SOLAR	35091	OLD_RVR1	12.5	8.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.1	1.26	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SIERRA_1_UNITS	35027	HISIERRA	9.11	51.60	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR1	35089	S_KERN	0.48	8.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR2	365563	Q885	0.36	4.10	1	Kern	South Kern PP	Aug NQC	Market
PG&E	VEDDER_1_SEKERN	35046	SEKR	9.11	9.46	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	ZZZZZ_OILDAL_1_UNIT 1	35028	OILDALE	9.11	0.00	RT	Kern	South Kern PP, Kern Oil	Retired	Net Seller
PG&E	ZZZZZ_ULTOGL_1_POSO	35035	ULTR PWR	9.11	0.00	1	Kern	South Kern PP, Kern Oil	Retired	QF/Selfgen
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	CLOVDL_1_SOLAR				0.00		NCNB	Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	Market
PG&E	CSTOGA_6_LNDFIL				0.00		NCNB	Fulton, Lakeville	Not modeled Energy Only	Market

PG&E	FULTON_1_QF				0.01		NCNB	Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	GEYS11_7_UNIT11	31412	GEYSER11	13.8	68.00	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	NCNB	Lakeville		Market
PG&E	GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS17_7_UNIT17	31422	GEYSER17	13.8	56.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	NCNB	Lakeville		Market
PG&E	GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	NCNB	Lakeville		Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	2	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYSRVL_7_WSPRNG				1.34		NCNB	Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	HILAND_7_YOLOWD				0.00		NCNB	Eagle Rock, Fulton, Lakeville	Not Modeled. Energy Only	Market
PG&E	IGNACO_1_QF				0.13		NCNB	Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	INDVLY_1_UNITS	31436	INDIAN V	9.1	1.11	1	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Net Seller
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.03	1	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.03	2	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	0.91	3	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	NCNB	Lakeville	Aug NQC	MUNI
PG&E	NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	NCNB	Lakeville	Aug NQC	MUNI
PG&E	NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	NCNB	Fulton, Lakeville	Aug NQC	MUNI
PG&E	NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	NCNB	Fulton, Lakeville	Aug NQC	MUNI
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.97	1	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market

PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.44	3	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.44	4	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
PG&E	POTTER_7_VECINO				0.00		NCNB	Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	1	NCNB	Lakeville		Market
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	2	NCNB	Lakeville		Market
PG&E	SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	47.00	1	NCNB	Lakeville		Market
PG&E	SNMALF_6_UNITS	31446	SONMA LF	9.1	3.92	1	NCNB	Fulton, Lakeville	Aug NQC	QF/Selfgen
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	0.49	1	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	1.21	2	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
PG&E	WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.50	1	NCNB	Fulton, Lakeville		Market
PG&E	WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.50	2	NCNB	Fulton, Lakeville		Market
PG&E	ZZZ_New Unit	365542	Q1221	13.8	35.00	1	NCNB	Eagle Rock, Fulton, Lakeville	No NQC - Pmax	Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	1	NCNB	Fulton, Lakeville	Retired	Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	2	NCNB	Fulton, Lakeville	Retired	Market
PG&E	ZZZZZZ_GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	0.00	1	NCNB	Fulton, Lakeville	Retired	Market
PG&E	ALLGNY_6_HYDRO1				0.08		Sierra	South of Table Mountain	Not modeled Aug NQC	Market
PG&E	APLHIL_1_SLABCK				0.00	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
PG&E	BANGOR_6_HYDRO				0.32		Sierra	South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BELDEN_7_UNIT 1	31784	BELDEN	13.8	119.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market

PG&E	BIOMAS_1_UNIT 1	32156	WOODLAND	9.11	24.94	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
PG&E	BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.56		Sierra	Weimer, Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BOGUE_1_UNITA1	32451	FREC	13.8	47.60	1	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	BOWMN_6_HYDRO	32480	BOWMAN	9.11	1.57	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	BUCKCK_2_HYDRO				0.29		Sierra	South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_OAKFLT				1.30		Sierra	South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	30.63	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	26.62	2	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	CAMPFW_7_FARWST	32470	CMP.FARW	9.11	2.90	1	Sierra	South of Table Mountain	Aug NQC	MUNI
PG&E	CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	42.00	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	Sierra	South of Table Mountain	Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	Sierra	South of Table Mountain	Aug NQC	MUNI

PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	34.66	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	35.34	2	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DAVIS_1_SOLAR1				0.41		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	DAVIS_1_SOLAR2				0.41		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	DAVIS_7_MNMETH				1.80		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	DEADCK_1_UNIT	31862	DEADWOOD	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
PG&E	DEERCR_6_UNIT 1	32474	DEER CRK	9.11	7.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.26	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market

PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	15.64	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_UNIT 5	32454	DRUM 5	13.8	50.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
PG&E	ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
PG&E	FMEADO_6_HELLHL	32486	HELLHOLE	9.11	0.32	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.00	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
PG&E	GOLDHL_1_QF				0.33		Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen

PG&E	GRIDLY_6_SOLAR	38054	GRIDLEY	60	0.00	1	Sierra	Pease, South of Table Mountain	Energy Only	Market
PG&E	GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	33.36	1	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	GRNLF1_1_UNITS	32491	GRNLEAF1	13.8	15.84	2	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	36.45	1	Sierra	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PG&E	HALSEY_6_UNIT	32478	HALSEY F	9.11	13.50	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
PG&E	HIGGNS_1_COMBIE				0.00		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
PG&E	HIGGNS_7_QFUNTS				0.23		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
PG&E	KANAKA_1_UNIT				0.00		Sierra	Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
PG&E	KELYRG_6_UNIT	31834	KELLYRDG	9.11	11.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI

PG&E	LIVEOK_6_SOLAR				0.51		Sierra	Pease, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	LODIEC_2_PL1X2	38124	LODI ST1	18	95.82	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
PG&E	LODIEC_2_PL1X2	38123	LODI CT1	18	184.18	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.94	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32458	RALSTON	13.8	82.13	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.94	2	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	NAROW1_2_UNIT	32466	NARROWS1	9.1	12.00	1	Sierra	South of Table Mountain	Aug NQC	Market
PG&E	NAROW2_2_UNIT	32468	NARROWS2	9.1	28.51	1	Sierra	South of Table Mountain	Aug NQC	MUNI
PG&E	NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	12.00	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	OROVIL_6_UNIT	31888	OROVLLE	9.11	7.50	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	OXBOW_6_DRUM	32484	OXBOW F	9.11	6.00	1	Sierra	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI

PG&E	PLACVL_1_CHILIB	32510	CHILIBAR	4.2	0.00	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	PLACVL_1_RCKCRE				2.18		Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	PLSNTG_7_LNCLND	32408	PLSNT GR	60	3.26		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	57.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.90	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	RIOOSO_1_QF				0.93		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
PG&E	ROLLIN_6_UNIT	32476	ROLLINSF	9.11	13.50	1	Sierra	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	SLYCRK_1_UNIT 1	31832	SLY.CR.	9.11	13.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	SPAULD_6_UNIT 3	32472	SPAULDG	9.11	6.50	3	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market

PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	7.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.40	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	SPI LI_2_UNIT 1	32498	SPILINCF	12.5	12.99	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
PG&E	STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
PG&E	ULTRCK_2_UNIT	32500	ULTR RCK	9.11	22.83	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	60.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
PG&E	WHEATL_6_LNDFIL	32350	WHEATLND	60	3.20		Sierra	South of Table Mountain	Not modeled Aug NQC	Market
PG&E	WISE_1_UNIT 1	32512	WISE	12	14.50	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	WISE_1_UNIT 2	32512	WISE	12	3.20	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market

PG&E	YUBACT_1_SUNSWT	32494	YUBA CTY	9.11	49.97	1	Sierra	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	Net Seller
PG&E	YUBACT_6_UNITA1	32496	YCEC	13.8	47.60	1	Sierra	Pease, Drum-Rio Oso, South of Table Mountain		Market
PG&E	ZZ_NA	32162	RIV.DLTA	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_UCDAVS_1_UNIT	32166	UC DAVIS	9.11	0.00	RN	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	365510	Q653F	0.48	4.92	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - est. data	Market
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Retired	QF/Selfgen
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	2	Sierra	Drum-Rio Oso, South of Table Mountain	Retired	QF/Selfgen
PG&E	BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.20	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.20	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.20	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	COGNAT_1_UNIT	33818	STCKNBIOMASS	13.8	42.33	1	Stockton	Weber	Aug NQC	Net Seller
PG&E	CRWCKS_1_SOLAR1	34051	Q539	34.5	0.00	1	Stockton	Tesla-Bellota	Energy Only	Market
PG&E	DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	FROGTN_1_UTICAA				0.49		Stockton	Tesla-Bellota, Stanislaus	Not Modeled Aug NQC	Market
PG&E	FROGTN_7_UTICA				0.00		Stockton	Tesla-Bellota, Stanislaus	Not modeled	Market

									Energy Only	
PG&E	LOCKFD_1_BEARCK				0.62		Stockton	Tesla-Bellota	Not modeled Energy Only	Market
PG&E	LOCKFD_1_KSOLAR				0.41		Stockton	Tesla-Bellota	Not modeled Energy Only	Market
PG&E	LODI25_2_UNIT 1	38120	LODI25CT	9.11	23.80	1	Stockton	Lockeford		MUNI
PG&E	MANTEC_1_ML1SR1				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Market
PG&E	PEORIA_1_SOLAR				0.62		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	PHOENX_1_UNIT				0.90		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	88.55	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	88.55	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	142.70	1	Stockton	Tesla-Bellota		Market
PG&E	SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	7.06	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	SPIFBD_1_PL1X2	34055	SPISONORA	13.8	2.32	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	SPRGAP_1_UNIT 1	34078	SPRNG GP	6	7.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	STNRES_1_UNIT	34056	STNSLSRP	13.8	19.27	1	Stockton	Tesla-Bellota	Aug NQC	Net Seller
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	4.79	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	5.39	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	3.54	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	16.19	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
PG&E	VLYHOM_7_SSJID				0.57		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	MUNI

PG&E	WEBER_6_FORWRD				4.20		Stockton	Weber	Not modeled Aug NQC	Market
PG&E	ZZ_NA	33830	GEN.MILL	9.11	0.00	1	Stockton	Lockeford	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	33687	STKTN WW	60	1.50	1	Stockton	Weber	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	33821	PAC_ETH	12.5	0.00	RN	Stockton	Weber	No NQC - hist. data	QF/Selfgen
PG&E	ZZZZZ_STOKCG_1_UNIT 1	33814	INGREDION	12.5	0.00	RN	Stockton	Tesla-Bellota	Retired	QF/Selfgen
SCE	ACACIA_6_SOLAR	29878	ACACIA_G	0.48	8.20	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	ALAMO_6_UNIT	25653	ALAMO SC	13.8	15.07	1	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.45	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.58	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.44	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.99	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	92.02	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.26	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	33.46	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	51.18	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	92.02	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.40	3	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.26	3	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.44	3	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.39	4	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market

SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.71	4	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	35.43	4	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.73	5	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	35.92	5	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.21	6	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.60	41	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.80	42	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	24.01	81	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	43.30	82	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_7_DAM7				0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGCRK_7_MAMRES				0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGSKY_2_BSKSR6	29742	BSKY G BC	0.42	8.20	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_BSKSR7	29703	BSKY G WABS	0.42	8.20	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_BSKSR8	29724	BSKY G ABSR	0.38	8.20	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR1	29727	BSKY G SMR	0.42	8.20	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR2	29701	BSKY_G_ESC	0.42	34.02	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR3	29745	BSKY_G_BD	0.42	8.20	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR4	29736	BSKY_G_BA	0.42	17.07	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR5	29739	BSKY_G_BB	0.42	2.05	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR6	29730	BSKY_G_SOLV	0.42	34.85	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR7	29733	BSKY_G_ADSR	0.42	20.50	1	BC/Ventura	Big Creek	Aug NQC	Market

SCE	CEDUCR_2_SOLAR1	25049	DUCOR1	0.385	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR2	25052	DUCOR2	0.385	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR3	25055	DUCOR3	0.385	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR4	25058	DUCOR4	0.385	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	DELSUR_6_CREST				0.00		BC/Ventura	Big Creek	Energy Only	Market
SCE	DELSUR_6_DRYFRB				2.05		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	DELSUR_6_SOLAR1				2.67		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	BC/Ventura	Big Creek, Rector, Vestal		Market
SCE	EDMONS_2_NSPIN	25605	EDMON1AP	14.4	16.86	1	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25606	EDMON2AP	14.4	16.86	2	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	3	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	4	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	5	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	6	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	7	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	8	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	9	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	10	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	11	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	12	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	13	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	14	BC/Ventura	Big Creek	Pumps	MUNI
SCE	GLDFGR_6_SOLAR1	25079	PRIDE B G	0.64	8.20	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	GLDFGR_6_SOLAR2	25169	PRIDE C G	0.64	4.67	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	GLOW_6_SOLAR	29896	APPINV	0.42	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	GOLETA_2_QF	24057	GOLETA	66	0.05		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
SCE	GOLETA_6_ELLWOD	29004	ELLWOOD	13.8	54.00	1	BC/Ventura	Ventura, S.Clara, Moorpark	Retirement requested effective	Market

									January 1, 2019	
SCE	GOLETA_6_EXGEN	24362	EXGEN2	13.8	4.10	G1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	GOLETA_6_EXGEN	24326	EXGEN1	13.8	2.83	S1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	GOLETA_6_GAVOTA	24057	GOLETA	66	0.26		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	GOLETA_6_TAJIGS	24057	GOLETA	66	2.84		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	LEBECS_2_UNITS	29051	PSTRIAG1	18	165.58	G1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29052	PSTRIAG2	18	165.58	G2	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29054	PSTRIAG3	18	165.58	G3	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29053	PSTRIAS1	18	170.45	S1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29055	PSTRIAS2	18	82.79	S2	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LITLRK_6_SEPV01				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	LITLRK_6_SOLAR1				2.05		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LITLRK_6_SOLAR2				0.82		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LITLRK_6_SOLAR4				1.23		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LNCSTR_6_CREST				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	BC/Ventura	Ventura, S.Clara, Moorpark		Market
SCE	MOORPK_2_CALABS	25081	WDT251	13.8	5.40	EQ	BC/Ventura	Ventura, Moorpark	Aug NQC	Market
SCE	MOORPK_6_QF	29952	CAMGEN	13.8	26.42	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	Market
SCE	MOORPK_7_UNITA1	24098	MOORPARK	66	2.12		BC/Ventura	Ventura, Moorpark	Not modeled Aug NQC	Market

SCE	NEENCH_6_SOLAR	29900	ALPINE_G	0.48	27.06	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	OASIS_6_CREST				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	OASIS_6_SOLAR1	25095	SOLARISG2	0.2	0.00	EQ	BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	OASIS_6_SOLAR2	25075	SOLARISG	0.2	8.20	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	OASIS_6_SOLAR3				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	OMAR_2_UNIT 1	24102	OMAR 1G	13.8	72.80	1	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 2	24103	OMAR 2G	13.8	74.00	2	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 3	24104	OMAR 3G	13.8	75.90	3	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 4	24105	OMAR 4G	13.8	81.44	4	BC/Ventura	Big Creek		Net Seller
SCE	ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	BC/Ventura	Ventura, Moorpark	Retirement requested effective October 1, 2018	Market
SCE	ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	BC/Ventura	Ventura, Moorpark	Retirement requested effective October 1, 2018	Market
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	1	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	2	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	3	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	4	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	5	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	6	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	7	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	8	BC/Ventura	Big Creek	Pumps	MUNI
SCE	PANDOL_6_UNIT	24113	PANDOL	13.8	23.32	1	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	PANDOL_6_UNIT	24113	PANDOL	13.8	23.32	2	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	PLAINV_6_BSOLAR	29917	SSOLAR)GR WKS	0.8	0.00	1	BC/Ventura	Big Creek	Energy Only	Market
SCE	PLAINV_6_DSOLAR	29914	WADR_PV	0.42	4.10	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	PLAINV_6_NLRSR1	29921	NLR_INVTR	0.42	0.00	1	BC/Ventura	Big Creek	Aug NQC	Market

SCE	PLAINV_6_SOLAR3	25089	CNTRL ANT G	0.42	0.00	1	BC/Ventura	Big Creek	Energy Only	Market
SCE	PLAINV_6_SOLARC	25086	SIRA SOLAR G	0.8	0.00	1	BC/Ventura	Big Creek	Energy Only	Market
SCE	PMDLET_6_SOLAR1				4.10		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	RECTOR_2_CREST	24212	RECTOR	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	RECTOR_2_KAWEAH	24212	RECTOR	66	0.03		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	RECTOR_2_KAWH 1	24212	RECTOR	66	0.19		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	RECTOR_2_QF	24212	RECTOR	66	0.07		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SCE	RECTOR_7_TULARE	24212	RECTOR	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled	Market
SCE	REDMAN_2_SOLAR				1.54		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	ROSMND_6_SOLAR				1.23		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	RSMSLR_6_SOLAR1	29984	DAWNGEN	0.8	8.20	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	RSMSLR_6_SOLAR2	29888	TWILGHTG	0.8	8.20	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	SAUGUS_6_MWDFTH	24135	SAUGUS	66	7.40		BC/Ventura	Big Creek	Not modeled Aug NQC	MUNI
SCE	SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	19.91	D1	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	SAUGUS_6_QF	24135	SAUGUS	66	0.62		BC/Ventura	Big Creek	Not modeled Aug NQC	QF/Selfgen
SCE	SAUGUS_7_CHIQCN	24135	SAUGUS	66	5.61		BC/Ventura	Big Creek	Not modeled Aug NQC	Market

SCE	SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.34		BC/Ventura	Big Creek	Not modeled Aug NQC	QF/Selfgen
SCE	SHUTLE_6_CREST				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	SNCLRA_2_HOWLNG	25080	GFID8045	13.8	7.63	EQ	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_SPRHYD				0.38		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	SNCLRA_2_UNIT1	24159	WILLAMET	3.8	19.03	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_6_OXGEN	24110	OXGEN	13.8	34.10	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_PROCGN	24119	PROCGEN	13.8	45.74	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_6_QF				0.00		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
SCE	SPRGVL_2_CREST	24215	SPRINGVL	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Energy Only	Market
SCE	SPRGVL_2_QF	24215	SPRINGVL	66	0.12		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SCE	SPRGVL_2_TULE	24215	SPRINGVL	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	SPRGVL_2_TULESC	24215	SPRINGVL	66	0.03		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.66	3.33	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.66	3.33	2	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.66	3.33	3	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.66	3.33	4	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.66	3.33	5	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	85.00	1	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 2	24144	SYCCYN2G	13.8	85.00	2	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 3	24145	SYCCYN3G	13.8	85.00	3	BC/Ventura	Big Creek	Aug NQC	Net Seller

SCE	SYCAMR_2_UNIT 4	24146	SYCCYN4G	13.8	85.00	4	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.57	D1	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.57	D2	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	VESTAL_2_KERN	24372	KR 3-1	11	0.24	1	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_KERN	24373	KR 3-2	11	0.23	2	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_RTS042				0.00		BC/Ventura	Big Creek, Vestal	Not modeled Energy Only	Market
SCE	VESTAL_2_SOLAR1	25066	TULRESLR	0.39	8.20	1	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_SOLAR2	25067	TULRESLR	0.39	1.78	1	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_SOLAR2	25068	TULRESLR	0.36	3.96	1	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_UNIT1				4.39		BC/Ventura	Big Creek, Vestal	Not modeled Aug NQC	Market
SCE	VESTAL_2_WELLHD	24116	WELLGEN	13.8	49.00	1	BC/Ventura	Big Creek, Vestal		Market
SCE	VESTAL_6_QF	29008	LAKEGEN	13.8	1.04	1	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen
SCE	WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	WARNE_2_UNIT	25652	WARNE2	13.8	38.00	2	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	ZZ_NA	24370	KAWGEN	13.8	0.00	1	BC/Ventura	Big Creek, Rector, Vestal	No NQC - hist. data	Market
SCE	ZZ_NA	24422	PALMDALE	66	0.00	1	BC/Ventura	Big Creek	No NQC - hist. data	Market
SCE	ZZ_NA	24340	CHARMIN	13.8	2.80	1	BC/Ventura	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
SCE	ZZ_VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	0.00	1	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen
SCE	ZZZ_New Unit	25171	PRIDE A G	0.64	4.10	1	BC/Ventura	Big Creek	No NQC - est. data	Market
SCE	ZZZ_New Unit	25170	PRIDE A G2	0.64	4.10	1	BC/Ventura	Big Creek	No NQC - est. data	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	BC/Ventura	Big Creek	Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	BC/Ventura	Big Creek	Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	BC/Ventura	Big Creek	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	0.00	1	BC/Ventura	Ventura, S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	0.00	2	BC/Ventura	Ventura, S.Clara, Moorpark	Retired	Market

Appendix A - List of physical resources by PTO, local area and market ID

SCE	ZZZZZ_MNDALY_7_UNIT 3	24222	MANDLY3G	16	0.00	3	BC/Ventura	Ventura, S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_SNCLRA_6_WILLMT	24159	WILLAMET	13.8	0.00	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Replaced by SNCLRA_2_UNIT1	QF/Selfgen
SCE	ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	LA Basin	Western	Retired by 2021	Market
SCE	ALTWD_1_QF	25635	ALTWIND	115	6.23	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ALTWD_1_QF	25635	ALTWIND	115	6.23	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ANAHM_2_CANYN1	25211	CanyonGT 1	13.8	49.40	1	LA Basin	Western		MUNI
SCE	ANAHM_2_CANYN2	25212	CanyonGT 2	13.8	48.00	2	LA Basin	Western		MUNI
SCE	ANAHM_2_CANYN3	25213	CanyonGT 3	13.8	48.00	3	LA Basin	Western		MUNI
SCE	ANAHM_2_CANYN4	25214	CanyonGT 4	13.8	49.40	4	LA Basin	Western		MUNI
SCE	ANAHM_7_CT	25208	DowlingCTG	13.8	40.64	1	LA Basin	Western	Aug NQC	MUNI
SCE	ARCOGN_2_UNITS	24011	ARCO 1G	13.8	57.40	1	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24012	ARCO 2G	13.8	57.40	2	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24013	ARCO 3G	13.8	57.40	3	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24014	ARCO 4G	13.8	57.40	4	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24163	ARCO 5G	13.8	28.70	5	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24164	ARCO 6G	13.8	28.70	6	LA Basin	Western	Aug NQC	Net Seller
SCE	BARRE_2_QF	24016	BARRE	230	0.00		LA Basin	Western	Not modeled	QF/Selfgen
SCE	BARRE_6_PEAKER	29309	BARPKGEN	13.8	47.00	1	LA Basin	Western		Market
SCE	BLAST_1_WIND	24839	BLAST	115	12.99	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind

SCE	BUCKWD_1_NPALM1	25634	BUCKWIND	115	0.98		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	BUCKWD_1_QF	25634	BUCKWIND	115	4.37	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.35	W5	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CABZON_1_WINDA1	29290	CABAZON	33	10.87	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CAPWD_1_QF	25633	CAPWIND	115	5.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	CENTER_2_QF	29953	SIGGEN	13.8	18.20	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	CENTER_2_RHONDO	24203	CENTER S	66	1.91		LA Basin	Western	Not modeled	QF/Selfgen
SCE	CENTER_2_SOLAR1				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	CENTER_6_PEAKER	29308	CTRPKGEN	13.8	47.00	1	LA Basin	Western		Market
SCE	CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	5.50	1	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	5.50	2	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHINO_2_APEBT1				20.00		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	CHINO_2_JURUPA				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CHINO_2_QF				0.47		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	CHINO_2_SASOLR				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CHINO_2_SOLAR				0.41		LA Basin	Eastern, Eastern Metro	Not modeled	Market
SCE	CHINO_2_SOLAR2				0.00		LA Basin	Eastern, Eastern Metro	Not modeled	Market

									Energy Only	
SCE	CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.96	D1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	CHINO_6_SMPPAP	24140	SIMPSON	13.8	22.78	D1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	CHINO_7_MILIKN	24024	CHINO	66	1.19		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	CORONS_2_SOLAR				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CORONS_6_CLRWTR	29338	CLRWTRCT	13.8	20.72	G1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	CORONS_6_CLRWTR	29340	CLRWTRST	13.8	7.28	S1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	DELAMO_2_SOLAR1				0.62		LA Basin	Western	Not modeled Aug NQC	Market
SCE	DELAMO_2_SOLAR2				0.72		LA Basin	Western	Not modeled Aug NQC	Market
SCE	DELAMO_2_SOLAR3				0.51		LA Basin		Not modeled Energy Only	
SCE	DELAMO_2_SOLAR4				0.53		LA Basin		Not modeled Energy Only	
SCE	DELAMO_2_SOLAR5				0.41		LA Basin		Not modeled Energy Only	
SCE	DELAMO_2_SOLAR6				0.82		LA Basin		Not modeled Energy Only	
SCE	DELAMO_2_SOLRC1				0.00		LA Basin	Western	Not modeled	Market

									Energy Only	
SCE	DELAMO_2_SOLRD				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	DEVERS_1_QF	25632	TERAWND	115	8.63	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_QF	25639	SEAWIND	115	10.35	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_SEPV05				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_1_SOLAR				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_1_SOLAR1				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_1_SOLAR2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_2_DHSPG2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DMDVLY_1_UNITS	25425	ESRP P2	6.9	0.00	8	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.13	3	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.13	4	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI

SCE	ELLIS_2_QF	24325	ORCOGEN	13.8	0.03	1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	ELSEGN_2_UN1011	29904	ELSEG5GT	16.5	131.50	5	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ELSEGN_2_UN1011	29903	ELSEG6ST	13.8	131.50	6	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ELSEGN_2_UN2021	29902	ELSEG7GT	16.5	131.84	7	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ELSEGN_2_UN2021	29901	ELSEG8ST	13.8	131.84	8	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ETIWND_2_CHMPNE				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	ETIWND_2_FONTNA	24055	ETIWANDA	66	0.11		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_2_RTS010	24055	ETIWANDA	66	0.62		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS015	24055	ETIWANDA	66	1.23		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS017	24055	ETIWANDA	66	1.44		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS018	24055	ETIWANDA	66	0.62		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS023	24055	ETIWANDA	66	1.03		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS026	24055	ETIWANDA	66	2.46		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS027	24055	ETIWANDA	66	0.82		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_SOLAR1				0.00		LA Basin		Not modeled Energy Only	
SCE	ETIWND_2_SOLAR2				0.00		LA Basin		Not modeled Energy Only	
SCE	ETIWND_2_SOLAR5				0.00		LA Basin		Not modeled	

									Energy Only	
SCE	ETIWND_2_UNIT1	24071	INLAND	13.8	23.36	1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	46.00	1	LA Basin	Eastern, Eastern Metro		Market
SCE	ETIWND_6_MWDETI	25422	ETI MWDG	13.8	2.80	1	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.67		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	LA Basin	Eastern, Eastern Metro	Retirement requested effective June 1, 2018	Market
SCE	ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	LA Basin	Eastern, Eastern Metro	Retirement requested effective June 1, 2018	Market
SCE	GARNET_1_SOLAR	24815	GARNET	115	0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	GARNET_1_SOLAR2	24815	GARNET	115	1.64		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	2.06	G1	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.71	G2	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	1.61	G3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_WIND	24815	GARNET	115	1.72	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_1_WINDS	24815	GARNET	115	5.96	W2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_1_WT3WND	24815	GARNET	115	0.00	W3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market

SCE	GARNET_2_HYDRO	24815	GARNET	115	0.54		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Market
SCE	GARNET_2_WIND1	24815	GARNET	115	2.97	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND2	24815	GARNET	115	3.10	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND3	24815	GARNET	115	3.34	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND4	24815	GARNET	115	2.60	QF	LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND5	24815	GARNET	115	0.80	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GLNARM_2_UNIT 5	29013	GLENARM5_CT	13.8	50.00	CT	LA Basin	Western		MUNI
SCE	GLNARM_2_UNIT 5	29014	GLENARM5_ST	13.8	15.00	ST	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.07	1	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 3	25042	PASADNA3	13.8	44.83	1	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 4	25043	PASADNA4	13.8	42.42	1	LA Basin	Western		MUNI
SCE	HARBGN_7_UNITS	24062	HARBOR G	13.8	76.27	1	LA Basin	Western	Mothballed	Market
SCE	HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	LA Basin	Western	Mothballed	Market
SCE	HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	LA Basin	Western	Mothballed	Market
SCE	HINSON_6_CARBGN	24020	CARBGEN1	13.8	14.83	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.83	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_LBECH1	24170	LBEACH12	13.8	65.00	1	LA Basin	Western		Market
SCE	HINSON_6_LBECH2	24170	LBEACH12	13.8	65.00	2	LA Basin	Western		Market
SCE	HINSON_6_LBECH3	24171	LBEACH34	13.8	65.00	3	LA Basin	Western		Market
SCE	HINSON_6_LBECH4	24171	LBEACH34	13.8	65.00	4	LA Basin	Western		Market
SCE	HINSON_6_SERRGN	24139	SERRFGEN	13.8	28.90	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	LA Basin	Western	Retired by 2021	Market
SCE	HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	LA Basin	Western	Retired by 2021	Market
SCE	INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market

SCE	INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Market
SCE	INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	LA Basin	Eastern, Valley, Valley-Devers	Mothballed	Market
SCE	LACIEN_2_VENICE	24337	VENICE	13.8	0.00	1	LA Basin	Western, El Nido	Aug NQC	MUNI
SCE	LAGBEL_2_STG1				9.60		LA Basin		Not modeled Aug NQC	Market
SCE	LAGBEL_6_QF	29951	REFUSE	13.8	0.29	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	48.00	1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	MESAS_2_QF	24209	MESA CAL	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_CORONA				2.23		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_LNDFL				1.23		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_MLBBTA				10.00		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_MLBBTB				10.00		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_ONTARO				2.26		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS032				0.62		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS033				0.41		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_TEMESC				1.65		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_6_DELGEN	29339	DELGEN	13.8	25.93	1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	LA Basin	Eastern, Eastern Metro		Market

SCE	MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.80		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
SCE	MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.79	1	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.79	2	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.79	3	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MTWIND_1_UNIT 1	29060	MOUNTWND	115	11.77	S1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 2	29060	MOUNTWND	115	5.88	S2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 3	29060	MOUNTWND	115	5.95	S3	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	OLINDA_2_COYCRK	24211	OLINDA	66	3.13		LA Basin	Western	Not modeled	QF/Selfgen
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.86	C1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.86	C2	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.86	C3	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.86	C4	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	6.91	S1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_QF	24211	OLINDA	66	0.01		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	OLINDA_7_LNDFIL	24211	OLINDA	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_ONTARO	24111	PADUA	66	0.12		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_SOLAR1	24111	PADUA	66	0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	PADUA_6_MWDSDM	24111	PADUA	66	5.51		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
SCE	PADUA_6_QF	24111	PADUA	66	0.38		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen

SCE	PADUA_7_SDIMAS	24111	PADUA	66	1.05		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	PANSEA_1_PANARO	25640	PANAERO	115	7.95	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	PWEST_1_UNIT	24815	GARNET	115	0.56	PC	LA Basin	Western	Aug NQC	Market
SCE	REDOND_7_UNIT 5	24121	REDON5 G	18	121.52	5	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 6	24122	REDON6 G	18	118.89	6	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 7	24123	REDON7 G	20	343.73	7	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 8	24124	REDON8 G	20	336.90	8	LA Basin	Western	Retired by 2021	Market
SCE	RENWD_1_QF	25636	RENWIND	115	1.33	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RENWD_1_QF	25636	RENWIND	115	1.32	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RHONDO_2_QF	24213	RIOHONDO	66	0.21		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		LA Basin	Western	Not modeled Aug NQC	Net Seller
SCE	RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_6_SOLAR1	24244	SPRINGEN	13.8	3.08		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	LA Basin	Eastern, Eastern Metro		Market
SCE	SANITR_6_UNITS	24324	SANIGEN	13.8	2.92	D1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen

SCE	SANTGO_2_LNDFL1				15.88		LA Basin		Not modeled Aug NQC	Market
SCE	SANTGO_2_MABBT1				2.00		LA Basin		Not modeled Aug NQC	Market
SCE	SANWD_1_QF	25646	SANWIND	115	4.11	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SANWD_1_QF	25646	SANWIND	115	4.11	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SBERDO_2_PSP3	24921	MNTV-CT1	18	140.56	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP3	24922	MNTV-CT2	18	140.56	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP3	24923	MNTV-ST1	18	243.89	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24924	MNTV-CT3	18	140.56	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24925	MNTV-CT4	18	140.56	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24926	MNTV-ST2	18	243.89	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_QF	24214	SANBRDNO	66	0.28		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_2_REDLND	24214	SANBRDNO	66	0.82		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS005	24214	SANBRDNO	66	1.03		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS007	24214	SANBRDNO	66	1.03		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market

SCE	SBERDO_2_RTS011	24214	SANBRDNO	66	1.44		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS013	24214	SANBRDNO	66	1.44		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS016	24214	SANBRDNO	66	0.62		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS048	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Energy Only	Market
SCE	SBERDO_2_SNTANA	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_6_MILLCK	24214	SANBRDNO	66	0.64		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	SENTNL_2_CTG1	29101	SENTINEL_G 1	13.8	92.09	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG2	29102	SENTINEL_G 2	13.8	92.40	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG3	29103	SENTINEL_G 3	13.8	92.36	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG4	29104	SENTINEL_G 4	13.8	91.98	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG5	29105	SENTINEL_G 5	13.8	91.83	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG6	29106	SENTINEL_G 6	13.8	92.16	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG7	29107	SENTINEL_G 7	13.8	91.84	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG8	29108	SENTINEL_G 8	13.8	91.56	1	LA Basin	Eastern, Valley-Devers		Market
SCE	TIFFNY_1_DILLON	29021	WINTEC6	115	11.93	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TRNSWD_1_QF	25637	TRANWIND	115	10.33	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind

SCE	VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_REDMTN	24160	VALLEYSC	115	2.20		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_RTS044	24160	VALLEYSC	115	3.28		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
SCE	VALLEY_5_SOLAR1	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Energy Only	Market
SCE	VALLEY_5_SOLAR2	25082	WDT786	34.5	8.20	EQ	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Market
SCE	VALLEY_7_BADLND	24160	VALLEYSC	115	0.58		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
SCE	VALLEY_7_UNITA1	24160	VALLEYSC	115	2.56		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
SCE	VENWD_1_WIND1	25645	VENWIND	115	2.50	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND2	25645	VENWIND	115	4.25	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND3	25645	VENWIND	115	5.05	EU	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VERNON_6_GONZL1	24342	FEDGEN	13.8	5.75	1	LA Basin	Western		MUNI
SCE	VERNON_6_GONZL2	24342	FEDGEN	13.8	5.75	1	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	LA Basin	Western		MUNI
SCE	VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	VILLPK_6_MWDYOR	24216	VILLA PK	66	4.20		LA Basin	Western	Not modeled Aug NQC	MUNI
SCE	VISTA_2_RIALTO	24901	VSTA	230	0.41		LA Basin	Eastern, Eastern Metro	Energy Only	Market

SCE	VISTA_2_RTS028	24901	VSTA	230	1.44		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	VISTA_6_QF	24902	VSTA	66	0.06		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	WALCRK_2_CTG1	29201	WALCRKG1	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG2	29202	WALCRKG2	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG3	29203	WALCRKG3	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG4	29204	WALCRKG4	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG5	29205	WALCRKG5	13.8	96.65	1	LA Basin	Western		Market
SCE	WALNUT_2_SOLAR				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	WALNUT_6_HILLGEN	24063	HILLGEN	13.8	39.51	D1	LA Basin	Western	Aug NQC	Net Seller
SCE	WALNUT_7_WCOVCT	24157	WALNUT	66	3.45		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WALNUT_7_WCOVST	24157	WALNUT	66	5.51		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WHTWTR_1_WINDA1	29061	WHITEWTR	33	16.30	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	ZZ_ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	Net Seller
SCE	ZZ_HINSON_6_QF	24064	HINSON	66	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZ_LAFRES_6_QF	24332	PALOGEN	13.8	0.00	D1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24327	THUMSGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24329	MOBGEN2	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24330	OUTFALL1	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24331	OUTFALL2	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen

SCE	ZZ_NA	29260	ALTAMSA4	115	0.00	1	LA Basin	Eastern, Valley-Devers	No NQC - hist. data	Wind
SCE	ZZ_SANTGO_6_COYOTE	24341	COYGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZZZZ_BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	0.00		LA Basin	Western	Retired	MUNI
SCE	ZZZZZZ_ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	0.00	4	LA Basin	Western, El Nido	Retired	Market
SDG&E	BORDER_6_UNITA1	22149	CALPK_BD	13.8	48.00	1	SD-IV	San Diego, Border		Market
SDG&E	BREGGO_6_DEGRSL				2.58		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	BREGGO_6_SOLAR	22082	BR GEN1	0.21	10.66	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.72	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CCRITA_7_RPPCHF	22124	CHCARITA	138	2.00	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CHILLS_1_SYCENG	22120	CARLTNHS	138	0.67	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	CHILLS_7_UNITA1	22120	CARLTNHS	138	1.52	2	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	CNTNLA_2_SOLAR1	23463	DW GEN3&4	0.33	51.25	1	SD-IV	None	Aug NQC	Market
SDG&E	CNTNLA_2_SOLAR2	23463	DW GEN3&4	0.33	0.00	2	SD-IV	None	Energy Only	Market
SDG&E	CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.65	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	31.66	G1	SD-IV	None	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	25.33	G2	SD-IV	None	Aug NQC	Market
SDG&E	CRELMN_6_RAMON1				0.82		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	CRELMN_6_RAMON2				2.05		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	13.25	1	SD-IV	San Diego	Aug NQC	Wind
SDG&E	CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.315	26.65	G1	SD-IV	None	Aug NQC	Market
SDG&E	CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.315	26.65	G2	SD-IV	None	Aug NQC	Market
SDG&E	DIVSON_6_NSQF	22172	DIVISION	69	44.23	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	ELCAJN_6_EB1BT1				7.50		SD-IV	San Diego, El Cajon	Not modeled.	Battery
SDG&E	ELCAJN_6_LM6K	23320	EC GEN2	13.8	48.10	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ELCAJN_6_UNITA1	22150	EC GEN1	13.8	45.42	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ENERSJ_2_WIND				41.10		SD-IV	None	Not modeled Aug NQC	Wind

SDG&E	ESCNDO_6_EB1BT1				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Battery
SDG&E	ESCNDO_6_EB2BT2				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Battery
SDG&E	ESCNDO_6_EB3BT3				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Battery
SDG&E	ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	1	SD-IV	San Diego, Esco		Market
SDG&E	ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.00	1	SD-IV	San Diego, Esco		Market
SDG&E	ESCO_6_GLMQF	22332	GOALLINE	69	36.41	1	SD-IV	San Diego, Esco	Aug NQC	Net Seller
SDG&E	IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	82.00	1	SD-IV	None	Aug NQC	Market
SDG&E	IVWEST_2_SOLAR1	23155	DU GEN1 G1	0.2	33.27	G1	SD-IV	None	Aug NQC	Market
SDG&E	IVWEST_2_SOLAR1	23156	DU GEN1 G2	0.2	28.23	G2	SD-IV	None	Aug NQC	Market
SDG&E	JACMSR_1_JACSR1				8.20		SD-IV	None	Not modeled Aug NQC	Market
SDG&E	LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	SD-IV	San Diego		Market
SDG&E	LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	SD-IV	San Diego		Market
SDG&E	LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	SD-IV	San Diego, Border		Market
SDG&E	LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	SD-IV	San Diego, Border		Market
SDG&E	LAROA1_2_UNITA1	20187	LRP-U1	16	0.00	1	SD-IV	None	Connect to CENACE/CFE grid for the summer – not available for ISO BAA RA purpose	Market
SDG&E	LAROA2_2_UNITA1	22996	INTBST	18	145.19	1	SD-IV	None		Market
SDG&E	LAROA2_2_UNITA1	22997	INTBCT	16	176.81	1	SD-IV	None		Market
SDG&E	LILIAC_6_SOLAR				1.23		SD-IV	San Diego	Not modeled.	Market
SDG&E	MRGT_6_MEF2	22487	MEF_MR2	13.8	47.90	1	SD-IV	San Diego, Miramar		Market
SDG&E	MRGT_6_MMAREF	22486	MEF_MR1	13.8	48.00	1	SD-IV	San Diego, Miramar		Market
SDG&E	MSHGTS_6_MMARLF	22448	MESAHGTS	69	4.42	1	SD-IV	San Diego, Mission	Aug NQC	Market
SDG&E	MSSION_2_QF	22496	MISSION	69	0.65	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MURRAY_6_UNIT				0.00		SD-IV	San Diego	Not modeled Energy Only	Market
SDG&E	NIMTG_6_NIQF	22576	NOISLMTR	69	36.15	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	OCTILO_5_WIND	23314	OCO GEN G1	0.69	35.12	G1	SD-IV	None	Aug NQC	Wind

SDG&E	OCTILO_5_WIND	23318	OCO GEN G2	0.69	35.12	G2	SD-IV	None	Aug NQC	Wind
SDG&E	OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	SD-IV	San Diego, Pala		Market
SDG&E	OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	1	SD-IV	San Diego, Pala		Market
SDG&E	OTAY_6_LNDFL5	22604	OTAY	69	0.00		SD-IV	San Diego, Border	Not modeled Energy Only	Market
SDG&E	OTAY_6_LNDFL6	22604	OTAY	69	0.00		SD-IV	San Diego, Border	Not modeled Energy Only	Market
SDG&E	OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	SD-IV	San Diego, Border		Market
SDG&E	OTAY_6_UNITB1	22604	OTAY	69	2.16	1	SD-IV	San Diego, Border	Aug NQC	Market
SDG&E	OTAY_7_UNITC1	22604	OTAY	69	1.78	3	SD-IV	San Diego, Border	Aug NQC	QF/Selfgen
SDG&E	OTMESA_2_PL1X3	22605	OTAYMGT1	18	165.16	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22606	OTAYMGT2	18	166.17	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22607	OTAYMST1	16	272.27	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22262	PEN_CT1	18	170.18	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22263	PEN_CT2	18	170.18	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22265	PEN_ST	18	225.24	1	SD-IV	San Diego		Market
SDG&E	PIOPIC_2_CTG1	23162	PIO PICO CT1	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG2	23163	PIO PICO CT2	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG3	23164	PIO PICO CT3	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.12	2	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	PTLOMA_6_NTCQF	22660	POINTLMA	69	19.76	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	SAMPSN_6_KELCO1	22704	SAMPSON	12.5	3.27	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	TERMEX_2_PL1X3	22982	TDM CTG2	18	156.44	1	SD-IV	None		Market
SDG&E	TERMEX_2_PL1X3	22983	TDM CTG3	18	156.44	1	SD-IV	None		Market
SDG&E	TERMEX_2_PL1X3	22981	TDM STG	21	280.13	1	SD-IV	None		Market
SDG&E	VLCNTR_6_VCSLR				0.96		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market
SDG&E	VLCNTR_6_VCSLR1				1.03		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market

SDG&E	VLCNTR_6_VCSLR2				2.05		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market
SDG&E	ZZ_NA	22916	PFC-AVC	0.6	0.00	1	SD-IV	San Diego	No NQC - hist. data	QF/Selfgen
SDG&E	ZZZ_New Unit	23352	ECO GEN2	0.55	5.30	1	SD-IV	None	No NQC - est. data	Market
SDG&E	ZZZ_New Unit	23287	Q429_G1	0.31	41.00	1	SD-IV	None	No NQC - est. data	Market
SDG&E	ZZZ_New Unit	23441	DW GEN2 G2	0.42	61.60	1	SD-IV	None	Aug NQC	Market
SDG&E	ZZZ_New unit	22783	EA5 REPOWER1	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZ_New unit	22784	EA5 REPOWER2	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZ_New unit	22786	EA5 REPOWER4	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZ_New unit	22787	EA5 REPOWER5	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZ_New unit	22788	EA5 REPOWER3	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZ_New Unit	22942	BUE GEN 1_G1	0.69	11.60	G1	SD-IV	None	No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	23100	ECO GEN1 G1	0.69	27.38	G1	SD-IV	None	No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22945	BUE GEN 1_G2	0.69	11.60	G2	SD-IV	None	No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22947	BUE GEN 1_G3	0.69	11.60	G3	SD-IV	None	No NQC - est. data	Wind
SDG&E	ZZZZZ_ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	SD-IV	San Diego, El Cajon	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA1	22233	ENCINA 1	14.4	0.00	1	SD-IV	San Diego, Encina	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market

SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	SD-IV	San Diego, Miramar	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	SD-IV	San Diego, Miramar	Retired	Market

○

VI. Appendix B – Effectiveness factors for procurement guidance

Table - Eagle Rock.

Effectiveness factors to the Eagle Rock-Cortina 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31406	GEYSR5-6	1	36
31406	GEYSR5-6	2	36
31408	GEYSER78	1	36
31408	GEYSER78	2	36
31412	GEYSER11	1	37
31435	GEO.ENGY	1	35
31435	GEO.ENGY	2	35
31433	POTTRVLY	1	34
31433	POTTRVLY	3	34
31433	POTTRVLY	4	34
38020	CITY UKH	1	32
38020	CITY UKH	2	32

Table - Fulton

Effectiveness factors to the Lakeville-Petaluma-Cotati 60 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31466	SONMA LF	**1**	52
31422	GEYSER17	1	12
31404	WEST FOR	1	12
31404	WEST FOR	2	12
31414	GEYSER12	1	12
31418	GEYSER14	1	12
31420	GEYSER16	1	12
31402	BEAR CAN	1	12
31402	BEAR CAN	2	12
38110	NCPA2GY1	1	12
38112	NCPA2GY2	1	12
32700	MONTICLO	1	10
32700	MONTICLO	2	10
32700	MONTICLO	3	10
31435	GEO.ENGY	1	6
31435	GEO.ENGY	2	6
31408	GEYSER78	1	6
31408	GEYSER78	2	6
31412	GEYSER11	1	6
31406	GEYSR5-6	1	6
31406	GEYSR5-6	2	6

Table - Lakeville

Effectiveness factors to the Vaca Dixon-Lakeville 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	38
31430	SMUDGEO1	1	38
31400	SANTA FE	1	38
31416	GEYSER13	1	38
31424	GEYSER18	1	38
31426	GEYSER20	1	38
38106	NCPA1GY1	1	38
38108	NCPA1GY2	1	38
31421	BOTTLERK	1	36
31404	WEST FOR	2	36
31402	BEAR CAN	1	36
31402	BEAR CAN	2	36
31404	WEST FOR	1	36
31414	GEYSER12	1	36
31418	GEYSER14	1	36
31420	GEYSER16	1	36
31422	GEYSER17	1	36
38110	NCPA2GY1	1	36
38112	NCPA2GY2	1	36
31446	SONMA LF	1	36
32700	MONTICLO	1	31
32700	MONTICLO	2	31
32700	MONTICLO	3	31
31406	GEYSR5-6	1	18
31406	GEYSR5-6	2	18
31405	RPSP1014	1	18
31408	GEYSER78	1	18
31408	GEYSER78	2	18
31412	GEYSER11	1	18
31435	GEO.ENGY	1	18
31435	GEO.ENGY	2	18
31433	POTTRVLY	1	15
31433	POTTRVLY	2	15
31433	POTTRVLY	3	15
38020	CITY UKH	1	15
38020	CITY UKH	2	15

Table – Rio Oso

Effectiveness factors to the Rio Oso-Atlantic 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32498	SPILINCF	1	49
32500	ULTR RCK	1	49
32456	MIDLFORK	1	33
32456	MIDLFORK	2	33
32458	RALSTON	1	33
32513	ELDRADO1	1	32
32514	ELDRADO2	1	32
32510	CHILIBAR	1	32
32486	HELLHOLE	1	31
32508	FRNCH MD	1	30
32460	NEWCSTLE	1	26
32478	HALSEY F	1	24
32512	WISE	1	24
38114	Stig CC	1	14
38123	Q267CT	1	14
38124	Q267ST	1	14
32462	CHI.PARK	1	8
32464	DTCHFLT1	1	4

Table – South of Table Mountain

Effectiveness factors to the Caribou-Palermo 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	7
31794	WOODLEAF	1	7
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31890	PO POWER	1	6
31890	PO POWER	2	6
31888	OROVLLE	1	6
31834	KELLYRDG	1	6
32450	COLGATE1	1	4
32466	NARROWS1	1	4
32468	NARROWS2	1	4
32452	COLGATE2	1	4
32470	CMP.FARW	1	4
32451	FREC	1	4
32490	GRNLEAF1	1	4
32490	GRNLEAF1	2	4
32496	YCEC	1	4
32494	YUBA CTY	1	4
32492	GRNLEAF2	1	4
32498	SPILINCF	1	2
31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2

31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31786	ROCK CK1	1	2
31790	POE 1	1	2
31792	POE 2	1	2
31784	BELDEN	1	2
32500	ULTR RCK	1	2
32156	WOODLAND	1	2
32510	CHILIBAR	1	2
32513	ELDRADO1	1	2
32514	ELDRADO2	1	2
32478	HALSEY F	1	2
32460	NEWCSTLE	1	1
32458	RALSTON	1	1
32512	WISE	1	1
32456	MIDLFORK	1	1
32456	MIDLFORK	2	1
32486	HELLHOLE	1	1
32508	FRNCH MD	1	1
32162	RIV.DLTA	1	1
32502	DTCHFLT2	1	1
32462	CHI.PARK	1	1
32464	DTCHFLT1	1	1
32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32166	UC DAVIS	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1
32472	SPAULDG	3	1
32480	BOWMAN	1	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
38124	LODI ST1	1	1
38123	LODI CT1	1	1
38114	STIG CC	1	1

Table – San Jose

Effectiveness factors to the Newark-NRS 115 kV line.

Bus#	Bus Name	ID	Eff Factor %

36895	Gia200	1	25
36858	Gia100	1	25
36859	Laf300	2	23
36859	Laf300	1	23
36863	DVRaGT1	1	23
36864	DVRbGt2	1	23
36865	DVRaST3	1	23
35854	LECEFGT1	1	19
35855	LECEFGT2	1	19
35856	LECEFGT3	1	19
35857	LECEFGT4	1	19
35858	LECEFST1	1	19
35860	OLS-AGNE	1	19
35863	CATALYST	1	12

Table – South Bay-Moss Landing

Effectiveness factors to the Moss Landing-Las Aguillas 230 kV line.

Bus#	Bus Name	ID	Eff Factor %
36209	SLD ENRG	1	20
36221	DUKMOSS1	1	20
36222	DUKMOSS2	1	20
36223	DUKMOSS3	1	20
36224	DUKMOSS4	1	20
36225	DUKMOSS5	1	20
36226	DUKMOSS6	1	20
36405	MOSSLND6	1	17
36406	MOSSLND7	1	17
35881	MEC CTG1	1	13
35882	MEC CTG2	1	13
35883	MEC STG1	1	13
35850	GLRY COG	1	12
35850	GLRY COG	2	12
35851	GROYPKR1	1	12
35852	GROYPKR2	1	12
35853	GROYPKR3	1	12
35623	SWIFT	BT	10
35863	CATALYST	1	10
36863	DVRaGT1	1	8
36864	DVRbGt2	1	8
36865	DVRaST3	1	8
36859	Laf300	2	8
36859	Laf300	1	8
36858	Gia100	1	7
36895	Gia200	1	7
35854	LECEFGT1	1	7
35855	LECEFGT2	1	7

35856	LECEFGT3	1	7
35857	LECEFGT4	1	7
35858	LECEFST1	1	7
35860	OLS-AGNE	1	7

Table – Ames/Pittsburg/Oakland

1) Effectiveness factors to the Ames-Ravenswood #1 115 kV line.

Bus#	Bus Name	ID	Eff Factor %
35304	RUSELCT1	1	10
35305	RUSELCT2	2	10
35306	RUSELST1	3	10
33469	OX_MTN	1	10
33469	OX_MTN	2	10
33469	OX_MTN	3	10
33469	OX_MTN	4	10
33469	OX_MTN	5	10
33469	OX_MTN	6	10
33469	OX_MTN	7	10
33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3
33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3
33113	LMECST1	1	3
33151	FOSTER W	1	2
33151	FOSTER W	2	2
33151	FOSTER W	3	2
33136	CCCSD	1	2
33141	SHELL 1	1	2
33142	SHELL 2	1	2
33143	SHELL 3	1	2
32900	CRCKTCOG	1	2
32910	UNOCAL	1	2
32910	UNOCAL	2	2
32910	UNOCAL	3	2
32920	UNION CH	1	2
32921	ChevGen1	1	2
32922	ChevGen2	1	2
32923	ChevGen3	3	2
32741	HILLSIDE_12	1	2
32901	OAKLND 1	1	1
32902	OAKLND 2	2	1
32903	OAKLND 3	3	1
38118	ALMDACT1	1	1

38119	ALMDACT2	1	1

2) Effectiveness factors to the Moraga-Claremont #2 115 kV line.

Bus#	Bus Name	ID	Eff Factor %
32741	HILLSIDE_12	1	15
32921	ChevGen1	1	15
32922	ChevGen2	1	15
32923	ChevGen3	3	15
32920	UNION CH	1	14
32910	UNOCAL	1	13
32910	UNOCAL	2	13
32910	UNOCAL	3	13
32901	OAKLND 1	1	10
32902	OAKLND 2	2	10
32903	OAKLND 3	3	10
38118	ALMDACT1	1	10
38119	ALMDACT2	1	10
33141	SHELL 1	1	9
33142	SHELL 2	1	9
33143	SHELL 3	1	9
33136	CCCSD	1	8
32900	CRCKTCOG	1	7
33151	FOSTER W	1	6
33151	FOSTER W	2	6
33151	FOSTER W	3	6
33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3
33113	LMECST1	1	3
33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3

Table – Herndon

Effectiveness factors to the Herndon-Manchester 115 kV line.

Bus#	Bus Name	ID	Eff Factor %
34624	BALCH 1	1	21.92
34616	KINGSRIV	1	20.746
34648	DINUBA E	1	19.595
34671	KRCDPCT1	1	19.51
34672	KRCDPCT2	1	19.51
34308	KERCKHOF	1	17.608

34343	KERCK1-2	2	17.608
34344	KERCK1-1	1	17.608
34345	KERCK1-3	3	17.608
34603	JGBSWLT	ST	14.797
34677	Q558	1	14.797
34690	CORCORAN_3	FW	14.797
34692	CORCORAN_4	FW	14.797
34696	CORCORANPV_S	1	14.797
34699	Q529	1	14.797
34610	HAAS	1	13.505
34610	HAAS	2	13.505
34612	BLCH 2-2	1	13.505
34614	BLCH 2-3	1	13.505
34431	GWF_HEP1	1	8.566
34433	GWF_HEP2	1	8.566
34617	Q581	1	4.803
34649	Q965	1	4.803
34680	KANSAS	1	4.803
34315	ADAMS_E	1	3.746
34467	GIFFEN_DIST	1	3.746
34563	STROUD_DIST	2	3.746
34563	STROUD_DIST	1	3.746
34608	AGRICO	2	3.746
34608	AGRICO	3	3.746
34608	AGRICO	4	3.746
34644	Q679	1	3.746
365502	Q632BC1	1	3.746
34301	CHOWCOGN	1	1.203
34305	CHWCHLA2	1	1.203

Table – LA Basin

Effectiveness factors to the Sylmar-Eagle Rock 230 kV line:

GENERATOR	MW Eff Fctr (%)
PASADNA1 13.8 #1	-25.58
PASADNA2 13.8 #1	-25.57
BRODWYSC 13.8 #1	-25.25
MALBRG3G 13.8 #S3	-15.52
ELSEG8ST 13.8 #8	-13.47
ELSEG7GT 16.5 #7	-13.46
ELSEG3 G 18.0 #3	-13.43
ELSEG4 G 18.0 #4	-13.42
CHEVGEN1 13.8 #1	-13.37
CHEVGEN2 13.8 #2	-13.37
VENICE 13.8 #1	-13.37

CHEVGEN5 13.8 #1	-13.36
CHEVGEN5 13.8 #2	-13.36
MOBGEN1 13.8 #1	-13.34
MOBGEN2 13.8 #1	-13.34
PALOGEN 13.8 #D1	-13.34
REDON5 G 18.0 #5	-13.27
REDON6 G 18.0 #6	-13.26
ARCO 1G 13.8 #1	-12.54
ARCO 2G 13.8 #2	-12.54
HARBOR G 13.8 #1	-12.54
HARBORG4 4.2 #LP	-12.54
HARBOR G 13.8 #HP	-12.54
LBEACH12 13.8 #2	-12.51
THUMSGEN 13.8 #1	-12.49
CARBGEN1 13.8 #1	-12.48
SERRFGEN 13.8 #D1	-12.48
CARBGEN2 13.8 #1	-12.48
LBEACH34 13.8 #3	-12.47
ICEGEN 13.8 #D1	-12.23
CTRPKGEN 13.8 #1	-11.36
SIGGEN 13.8 #D1	-11.35
ALAMT3 G 18.0 #3	-10.66
ALAMT4 G 18.0 #4	-10.66
EME WCG1 13.8 #1	-9.96
OLINDA 66.0 #1	-9.51
BREAPWR2 13.8 #C1	-9.5
BARPKGEN 13.8 #1	-8.7
HUNT1 G 13.8 #1	-8.3
HUNT2 G 13.8 #2	-8.3
SANTIAGO 66.0 #1	-7.73
CanyonGT 1 13.8 #1	-7.34
CanyonGT 2 13.8 #2	-7.34
DowlingCTG 13.8 #1	-7.34
SANIGEN 13.8 #D1	-5.99
CIMGEN 13.8 #D1	-5.98
SIMPSON 13.8 #D1	-5.97
MRLPKGEN 13.8 #1	-5.75
DELGEN 13.8 #1	-5.72
VSTA 66.0 #1	-5.29
MESAHGTS 69.0 #1	-5.28
ETWPKGEN 13.8 #1	-5.27
CLTNDREW 13.8 #1	-5.27
CLTNCTRY 13.8 #1	-5.27

CLTNAGUA	13.8 #1	-5.27
RERC1G	13.8 #1	-5.26
RERC2G	13.8 #1	-5.26
SPRINGEN	13.8 #1	-5.26
INLAND	13.8 #1	-5.25
RERC2G3	16.5 #1	-5.21
RERC2G4	16.5 #1	-5.21
MTNVIST3	18.0 #3	-5.15
MTNVIST4	18.0 #4	-5.14
MNTV-CT1	18.0 #1	-5.06
MNTV-CT2	18.0 #1	-5.06

Table – Rector

Effectiveness factors to the Rector-Vestal 230 kV line:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24370	KAWGEN	1	51
24306	B CRK1-1	1	45
24306	B CRK1-1	2	45
24307	B CRK1-2	3	45
24307	B CRK1-2	4	45
24319	EASTWOOD	1	45
24323	PORTAL	1	45
24308	B CRK2-1	1	45
24308	B CRK2-1	2	45
24309	B CRK2-2	3	45
24309	B CRK2-2	4	45
24310	B CRK2-3	5	45
24310	B CRK2-3	6	45
24315	B CRK 8	81	45
24315	B CRK 8	82	45
24311	B CRK3-1	1	45
24311	B CRK3-1	2	45
24312	B CRK3-2	3	45
24312	B CRK3-2	4	45
24313	B CRK3-3	5	45
24317	MAMOTH1G	1	45
24318	MAMOTH2G	2	45
24314	B CRK 4	41	43
24314	B CRK 4	42	43

Table – San Diego

Effectiveness factors to the Imperial Valley – El Centro 230 kV line (i.e., the "S" line):

GENERATOR	MW Eff Factor (%)
INTBCT 16.0 #1	25.42
INTBST 18.0 #1	25.42
DW GEN2 G1 0.4 #1	25.18
DW GEN1 G1 0.3 #G1	25.15
DU GEN1 G2 0.2 #G2	25.14
DW GEN1 G2 0.3 #G2	25.14
DU GEN1 G1 0.2 #G1	25.08
DW GEN3&4 0.3 #1	25.08
OCO GEN G1 0.7 #G1	22.71
OCO GEN G2 0.7 #G2	22.71
ECO GEN1 G 0.7 #G1	21.85
Q644G 0.3 #1	21.11
OTAYMGT1 18.0 #1	17.82
OTAYMGT2 18.0 #1	17.82
OTAYMST1 16.0 #1	17.82
PIO PICO 1 13.8 #1	17.52
PIO PICO 1 13.8 #1	17.52
PIO PICO 1 13.8 #1	17.52
KUMEYAAY 0.7 #1	17.05
EC GEN2 13.8 #1	16.91
EC GEN1 13.8 #1	16.89
OY GEN 13.8 #1	16.82
OTAY 69.0 #1	16.81
OTAY 69.0 #3	16.81
DIVISION 69.0 #1	16.78
NOISLMTR 69.0 #1	16.75
SAMPSON 12.5 #1	16.69
CABRILLO 69.0 #1	16.62
LRKSPBD1 13.8 #1	16.56
LRKSPBD2 13.8 #1	16.56
POINTLMA 69.0 #2	16.56
CALPK_BD 13.8 #1	16.55
MESAHGTS 69.0 #1	16.48
CARLTNHS 138.0 #1	16.46

CARLTNHS 138.0 #2	16.46
MISSION 69.0 #1	16.39
EASTGATE 69.0 #1	16.25
MEF MR1 13.8 #1	16.23
CHCARITA 138.0 #1	16.21
MEF MR2 13.8 #1	16.08
LkHodG1 13.8 #1	15.60
LkHodG2 13.8 #1	15.60
GOALLINE 69.0 #1	15.23
PEN_CT1 18.0 #1	14.98
CALPK_ES 13.8 #1	14.97
ENCINA 2 14.4 #1	14.96
ES GEN 13.8 #1	14.96
PEN_CT2 18.0 #1	14.93
PEN_ST 18.0 #1	14.92
SANMRCOS 69.0 #1	14.84
PA GEN1 13.8 #1	14.40
PA GEN2 13.8 #1	14.40
BR GEN1 0.2 #1	13.67
CAPSTRNO 138.0 #1	11.88

Resources connected to Imperial Valley substation or nearby SDG&E-owned substations in the area are most effective in mitigating the S-Line overload concern.