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 2016 and 2017 Compliance Years	Rulemaking 14-10-010 (Filed October 16, 2014)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
LOCAL CAPACITY TECHNICAL ANALYSIS AND FLEXIBLE CAPACITY NEEDS ASSESSMENT FOR 2018

The California Independent System Operator Corporation (CAISO) hereby provides its Final Flexible Capacity Needs Assessment and Local Capacity Technical Analysis for 2018.

The Final Flexible Capacity Needs Assessment is included as Attachment A to this filing and can be accessed at:
http://www.caiso.com/Documents/2018FinalFlexibleCapacityNeedsAssessment.pdf.

The Final Local Capacity Technical Analysis is included as Attachment B to this filing and can be accessed at:
http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf.

Respectfully submitted,

By: */s/ Jordan Pinjuv*
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: May 1, 2017

ATTACHMENT A

2018

Flexible Capacity Needs Assessment

April 28, 2017

Final Flexible Capacity Needs Assessment for 2018

April 28, 2017

Table of Contents

1. Introduction 3
2. Summary 3
3. Defining the ISO System-Wide Flexible Capacity Need 5
4. Forecasting Minute-by-Minute Net load 6
   - 4.1 Building the Forecasted Variable Energy Resource Portfolio 6
   - 4.2 Building Minute-by-Minute Net Load Curves 8
5. Calculating the Monthly Maximum Three-Hour Net load Ramps Plus 3.5 Percent Expected Peak-Load 8
6. Calculating the Seasonal Percentages Needed in Each Category 10
   - 6.1 Calculating the Forecast Percentages Needed in Each Category in Each Month 11
   - 6.2 Analyzing Ramp Distributions to Determine Appropriate Seasonal Demarcations 13
   - 6.3 Calculate a Simple Average of the Percent of Base Flexibility Needs 15
7. Allocating the Flexible Capacity Needs to Local Regulatory Authorities 16
8. Determining the Seasonal Must-Offer Obligation Period 22
9. Next Steps 24
10. Appendix 25

1. Introduction

The ISO conducts an annual flexible capacity technical study to determine the flexible capacity needed to help ensure ISO system reliability as provided in 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 final flexible capacity needs assessment specifying the ISO's forecast flexible capacity needs in 2018.

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 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 2018 are --

1) The ISO made two enhancements to the 2018 study methodology.

    a. The ISO did not receive an Additional Achievable Energy Efficiency (AAEE) profile from the CEC. Therefore, the ISO has removed of the shaped profile for AAEE from the study process.

b. The ISO modified the method used to calculate the delta load component of the flexible capacity requirements allocation after identifying instability in the flexible capacity allocations based on the contribution of Δ Load, particularly during summer months. The issue with the prior mathematical equation was that divisor in the allocation can become small and cause unstable, and anomalous results. The new methodology resolves the issue and produces more stable flexible capacity requirements allocations.

Item (b) is discussed in greater detail in Section 7, below.

2) System-wide flexible capacity needs are greatest in the non-summer months and range from 10,908 MW in July to 15,743 MW in December.

3) The minimum amount of flexible capacity needed from the "base flexibility" category is 54 percent of the total amount of installed or available flexible capacity in the summer months (May – September) and 38 percent of the total amount of flexible capacity for the non-summer months (October – April).

4) 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 3:00 p.m. to 8:00 p.m. for May through September, and 2:00 p.m. to 7:00 p.m. for January through April and October through December. These hours are different from those in Final Flexible Capacity Needs Assessment for 2017.

5) In previous years, the ISO has published advisory requirements the two years following the upcoming RA year. At the time of publication, the ISO is processing results for 2019 and 2020. Once this data is processed, the ISO will issue advisory results for those years.

The ISO received data from all LSEs.

Only PG&E and the Center for Energy Efficiency and Renewable Technology (CEERT) submitted comments on the Draft Flexible Capacity Needs Assessment. The ISO's response to these comments are contained in the appendix of this report.

3. Defining the ISO System-Wide Flexible Capacity Need

Based on the methodology described in the ISO 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 2018 RA compliance year, the ISO will continue to set ε equal to zero.

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 ramps 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 from all months within a season; and

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

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

This methodology allows the ISO to make enhancements and assumptions based on its experience and new information becoming available. Based on its experience in the previous iteration of this study process, the ISO as noted above, the ISO has only made two minor modifications to the methodology used for the 2018 Flexible Capacity Needs Assessment: AAEE profiles are not included in the study and modified the method used to calculate the delta load component of the flexible capacity requirements allocation.

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 net load curves for 2017.

4.1 Building the Forecasted Variable Energy Resource Portfolio

To collect the necessary data, the ISO sent a data request on December 8, 2016 to the scheduling coordinators for all LSEs representing load in the ISO balancing area.[3] The deadline for submitting the data was January 15, 2017. The ISO sent follow-up data requests to LSEs that did not submit data by the January 15 deadline. 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 asked for information on resources internal and external to the ISO. For resources that are external or pseudo-tie to the ISO, the ISO requested additional information as to whether the resource is or will be a dynamically scheduled or pseudo-tie resource. The ISO only included external or pseudo-tie resources in the flexible capacity requirements assessment if they were dynamic system dynamically or pseudo-tied into 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 2018. The forecasted aggregated variable energy resource fleet capacity is provided in Table 1.

---

[3] A reminder notice was also sent out on January 4, 2017.

[4] Net-load load is defined as load minus wind minus solar.

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

Resource Type	Existing MW (2016)	2017 MW	2018 MW
ISO Solar PV	8,127	8,505	9,082
ISO Solar Thermal	1,193	1,183	1,178
ISO Wind	4,900	4,871	4,866
Incremental behind-the-meter Solar PV		1,604	1,725
Total Variable Energy Resource Capacity in the 2017 Flexible Capacity Needs Assessment[6]	14,220	16,163	16,851
Non ISO Resources All external VERS not-firmed by external BAA		1,182	1,202
Total internal and non-firmed external VERs	14,220	17,345	18,053
Incremental New Additions in Each Year		3,125	708

Although Table 1 aggregates the variable energy resources system wide, the ISO conducted the assessment using location-specific information. 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 2016. 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:

$$2017\ W_{Mth\_Sim\_1\text{-}min} = 2016W_{Act\_1\text{-}min} * 2017W_{Mth\ Capacity} / 2016W_{Mth\ Capacity}$$

Given the small amount of incremental wind resources coming on line, this approach allows the ISO to maintain the load/wind correlation for over 94% of the forecasted wind capacity output.

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 has also included incremental behind-the-meter solar production for behind-the-meter solar PV that occurs after 2016. Although existing behind-the-meter solar PV is captured by changes in the 2016 historic load, additional incremental behind-the-meter solar PV that is installed after 2016 is not captured in load. If this capacity is not fully accounted for 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

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

the calculation of the three hour net load ramp. Including this incremental capacity allows the ISO to more accurately capture the forecasted three hour net load ramp. Because behind-the-meter solar is solar PV, the ISO included the contribution of the incremental behind-the-meter 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. The ISO has not identified a material change from including the behind-the-meter resources in the summer months at this time, but will continue to work with the CEC to determine if additional modifications are needed as part of the next flexible capacity technical needs study.

4.2 Building Minute-by-Minute Net Load Curves

The ISO used the CEC 2016 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 month of 2016 using an expected load growth factor of the monthly peak forecast divided by the actual 2016 monthly peak. The ISO used this same methodology in the 2017 assessment.

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 and solar resources from the load to generate the minute-by-minute net load curves necessary to conduct the flexible capacity needs assessment.

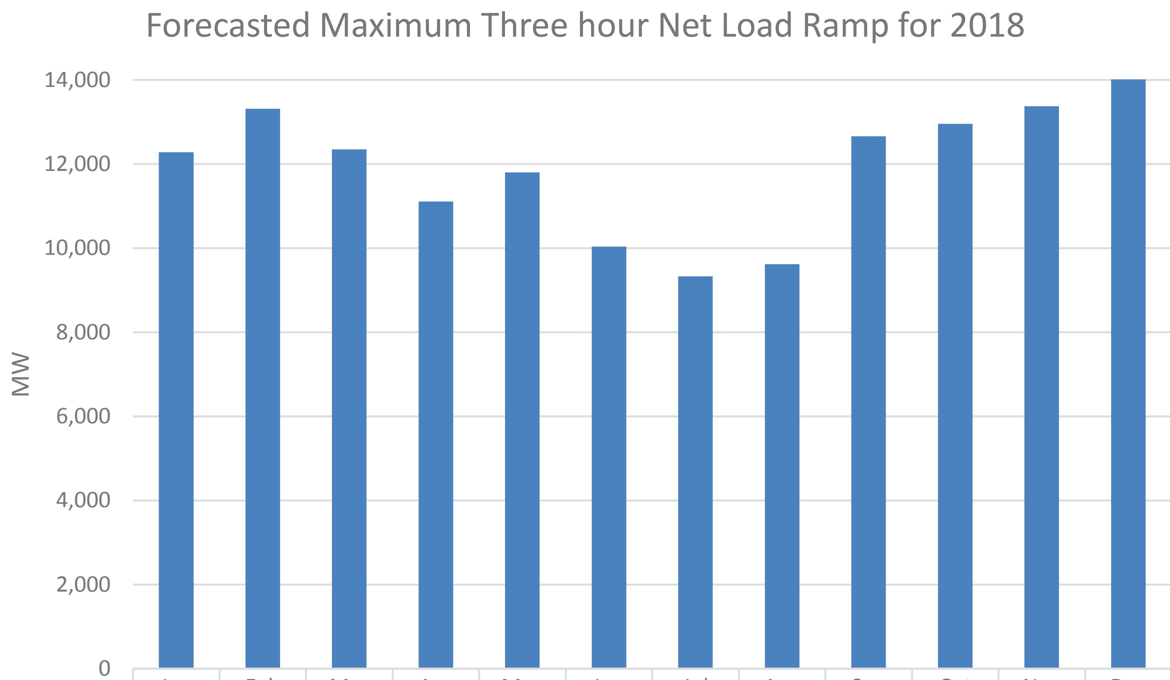
5. Calculating the Monthly Maximum Three-Hour Net load Ramps Plus 3.5 Percent Expected Peak-Load

The ISO, using the net load forecast developed in Section 4, calculated the maximum three-hour net load ramp for each month. The ISO system-wide, largest three-hour net load ramps for each month are detailed in Figure 1.

---

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

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



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	12,282	13,313	12,352	11,111	11,803	10,039	9,326	9,617	12,660	12,954	13,376	14,567

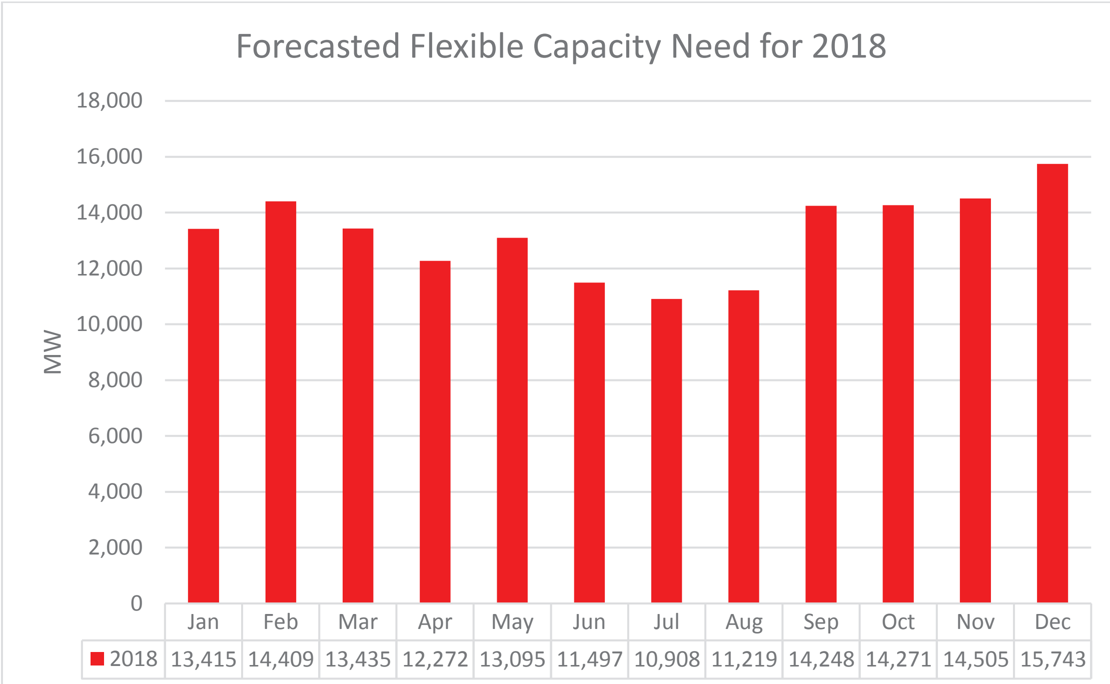
The results for the non-summer months of 2018 are higher than those predicted in the summer months. This is consistent with historical trends. Further, although the three hour net load ramps are forecasted to increase in each month, the differential between the summer maximums and the non-summer maximums remained fairly stable (approximately 5,000 MW difference between July and December).

As part of the 2018 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 2018. These totals are shown in Figure 2 below.

---

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

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



6. Calculating the Seasonal Percentages Needed in Each Category

As described in 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 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

---

[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

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:

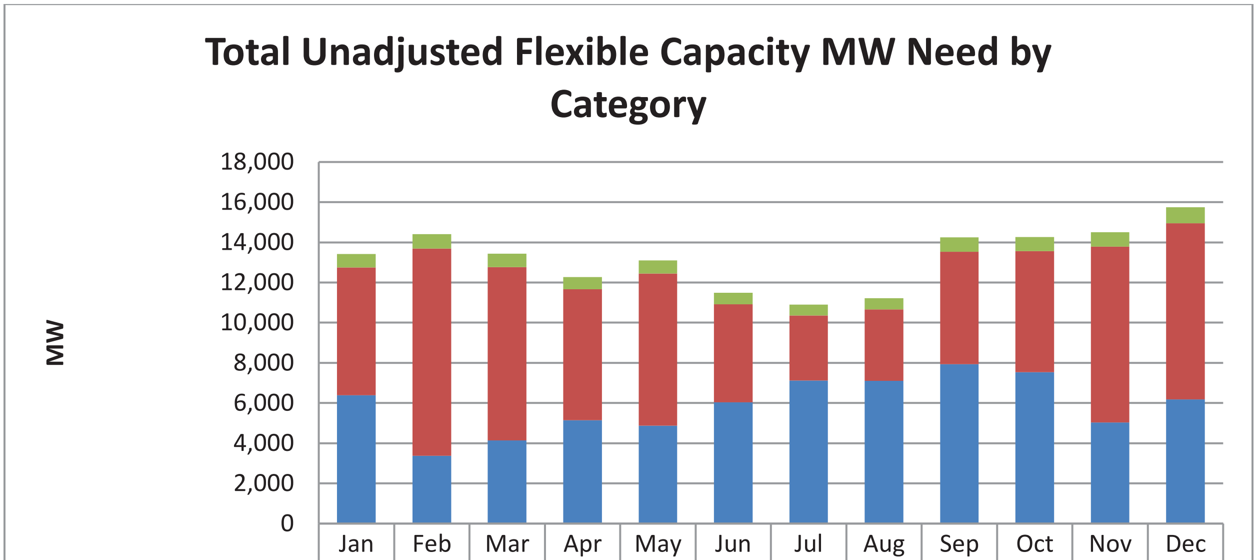
1) Calculate the forecast percentages needed in each category in each month;
2) Analyze the distributions of both largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations; and
3) Calculate a simple average of the percent of base flexibility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

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

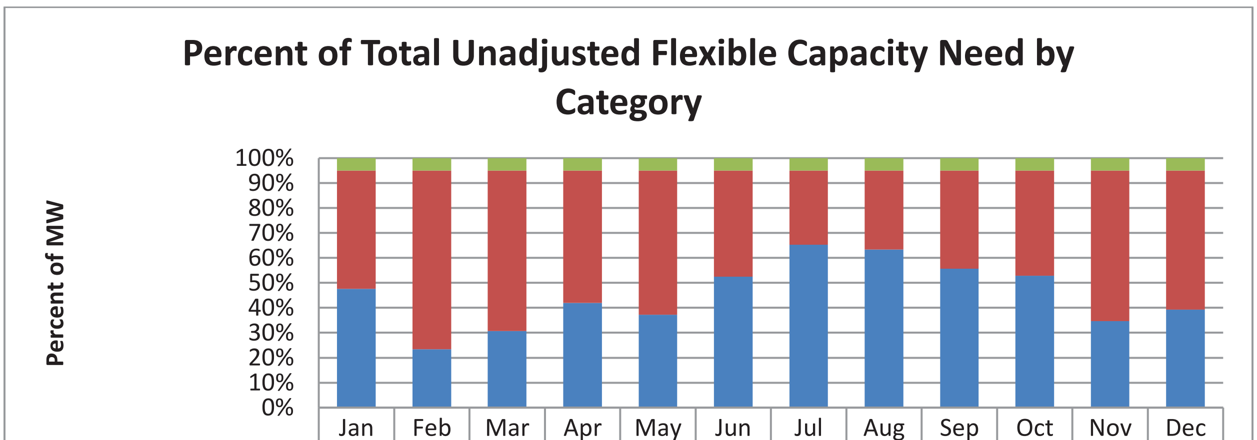
Based on the categories defined above, the ISO calculated the system level needs for 2018 based only on the maximum monthly 3-hour net load calculation. Then the ISO calculated the quantity needed in each category in each month based on the above descriptions. The ISO calculated the secondary net load 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. For example, for the month of January, the ISO added 90 percent of the contingency reserves portion into the base flexibility category 1, 5 percent into the peak flexibility category 2, and the final 5 percent into the super-peak flexibility category 3. The calculation of flexible capacity needs for each category for 2018 is shown in Figure 3.

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.

Figure 3: ISO System-Wide Flexible Capacity Monthly Calculation by Category for 2018



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	671	720	672	614	655	575	545	561	712	714	725	787
Peak Flexibility	6,351	10,321	8,630	6,511	7,564	4,889	3,235	3,549	5,607	6,020	8,750	8,778
Base Flexibility	6,393	3,367	4,133	5,147	4,876	6,033	7,128	7,109	7,928	7,537	5,030	6,178



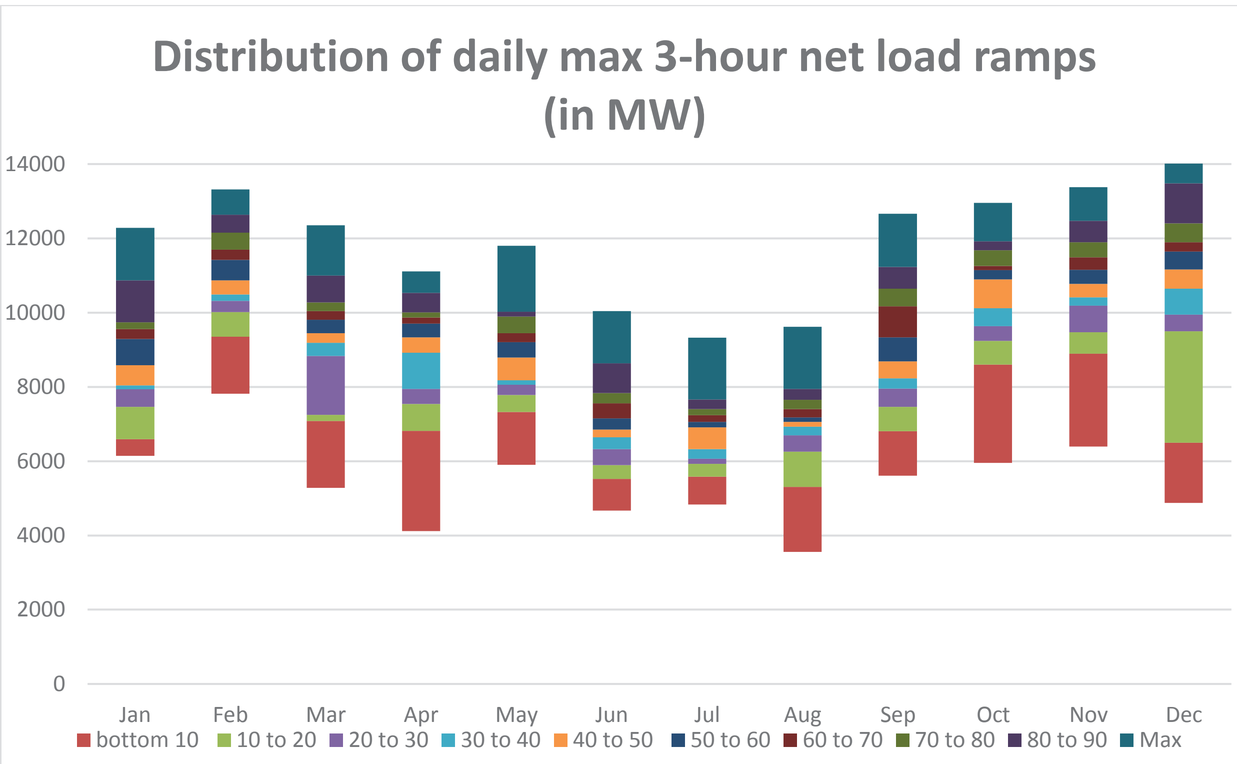
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Peak Flexibility	47%	72%	64%	53%	58%	43%	30%	32%	39%	42%	60%	56%
Base Flexibility	48%	23%	31%	42%	37%	52%	65%	63%	56%	53%	35%	39%

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

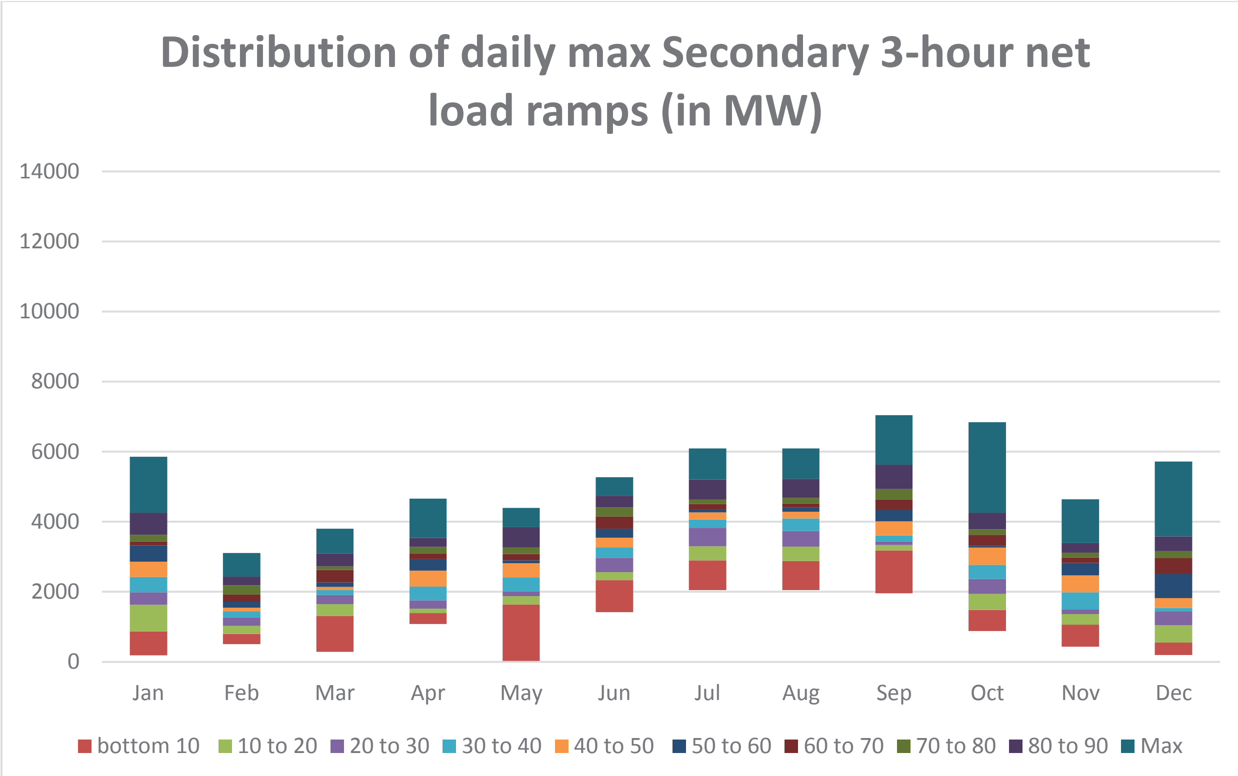
To determine the seasonal percentages for each flexible capacity category, the ISO analyzed the distributions of the largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations for the base flexibility category. The secondary net load 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.

Figure 4: Distribution of Daily Primary 3-hour Net Load Ramps for 2018



10 Last year's assessment refers to the 2014 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 5: Distribution of Secondary 3-hour Net load Ramps for 2018



As Figure 4 shows, the distribution (*i.e*. the width of the distribution for each month) of the daily maximum three-hour net load ramps is slightly narrower 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 resemble summer days, while other days resemble 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 things. First, given the breadth 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.

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

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 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.

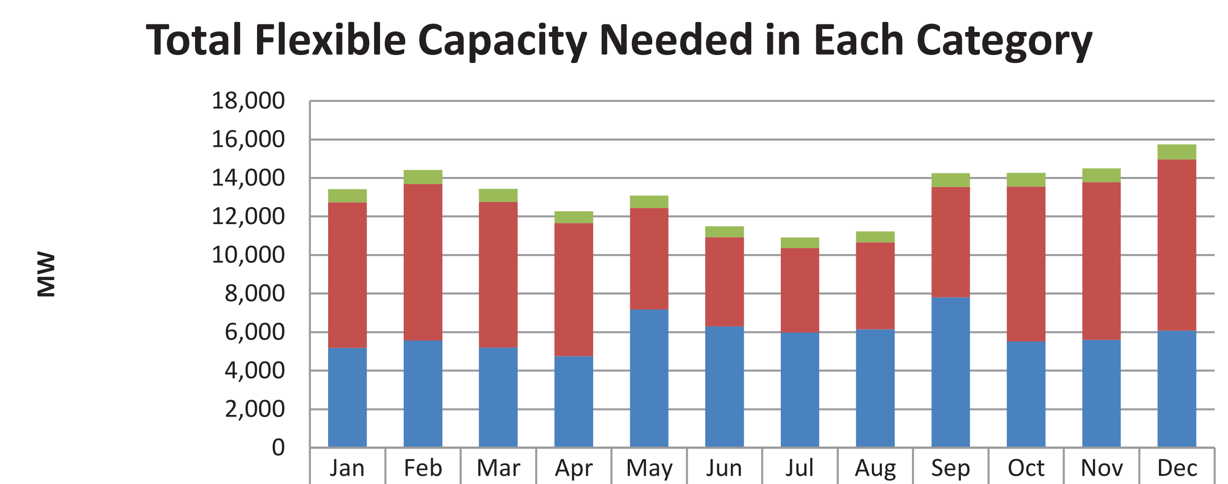
Second, adding flexible capacity procurement to the RA program will increase the process and information requirements. Maintaining a seasonal demarcation that is consistent with the current RA program will reduce the potential for errors in resource adequacy showings.

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 38 percent of the ISO system flexible capacity need for the non-summer months and 55 percent for the summer months. Peak flexible capacity resources could be used to fulfill up to 38 percent of non-summer flexibility needs and 55 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 2017 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 2018



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	671	720	672	614	655	575	545	561	712	714	725	787
Peak Flexibility	7,561	8,121	7,572	6,917	5,262	4,620	4,384	4,509	5,726	8,043	8,175	8,873
Base Flexibility	5,183	5,567	5,191	4,742	7,178	6,302	5,979	6,150	7,810	5,514	5,604	6,083

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)

In the Flexible Capacity Needs Assessment for 2017, the ISO started to identify instability in the flexible capacity allocations based on the contribution of Δ Load, particularly during summer months. The ISO, as part of its February 1, 2017 stakeholder call identified the need to modify the determination of Δ Load allocations as necessary for this year's study process. As a primary assessment, the ISO calculated LRA's allocation of Δ Load using last year's methodology. The results demonstrated that the results were overly sensitive to small Δ Load on select days and could result in allocations in excess of flexible capacity needs for some LSE, while other LSEs would receive comparable negative allocations. As such, the ISO has calculated 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.

$$\Delta L_{sc,2018} = L^{E}_{sc,2016}\left(\frac{L^{E}_{2018}}{L^{E}_{2016}}\right) - L^{S}_{sc,2016}\left(\frac{L^{S}_{2018}}{L^{S}_{2016}}\right),$$

where $L = Load$,

2016 has metered load, 2018 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

$$\Sigma\Delta L_{sc,2018} = \Delta L_{2018}$$

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 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 2018.[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_2018NetLoadData.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.

[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.

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

Table 2: Contribution to Maximum 3-hour Continuous Net load Ramp for 2018

Month	Average of Load contribution 2018	Average of Solar PV contribution 2018	Average of BTM Solar contribution 2018	Average of Wind contribution 2018	Total percent 2018
January	39.99%	-55.68%	-4.85%	0.53%	100%
February	38.51%	-54.40%	-4.57%	-2.52%	100%
March	31.60%	-59.86%	-7.63%	-0.91%	100%
April	21.23%	-70.60%	-8.93%	0.76%	100%
May	14.80%	-71.96%	-7.28%	-5.95%	100%
June	8.87%	-80.17%	-9.57%	-1.38%	100%
July	5.76%	-83.32%	-11.55%	0.64%	100%
August	11.19%	-86.89%	-12.40%	10.48%	100%
September	16.45%	-73.16%	-10.35%	-0.03%	100%
October	21.34%	-64.77%	-10.30%	-3.59%	100%
November	28.04%	-60.41%	-9.98%	-1.56%	100%
December	42.44%	-48.38%	-5.90%	-3.28%	100%

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 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 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 2016 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 2016. 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 2016 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] Table 3 shows the CPUC jurisdictional LSEs' combined relative contribution to each of the each of the factors (Δ Load, Δ Wind, Δ Solar PV, and Δ BTM Solar) included in the allocation methodology.

Table 3: CPUC Jurisdictional LSEs' Contribution to Flexible Capacity Needs[15]

	Δ Load	Δ PV Fixed	Δ BTM Solar	Δ Wind
Jan	93.34%	92.01%	99.01%	87.43%
Feb	89.64%	92.06%	99.01%	87.31%
Mar	101.99%	92.07%	99.01%	87.32%
Apr	114.01%	92.12%	99.01%	87.23%
May	105.85%	92.12%	99.01%	87.16%
Jun	98.70%	92.12%	99.01%	87.11%
Jul	102.03%	92.12%	99.01%	87.01%
Aug	124.09%	92.12%	99.01%	87.02%
Sep	104.70%	92.28%	99.01%	87.08%
Oct	95.07%	92.28%	99.01%	87.22%
Nov	95.58%	92.28%	99.01%	87.23%
Dec	93.28%	92.39%	99.01%	87.15%

Finally, 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 7. 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.

---

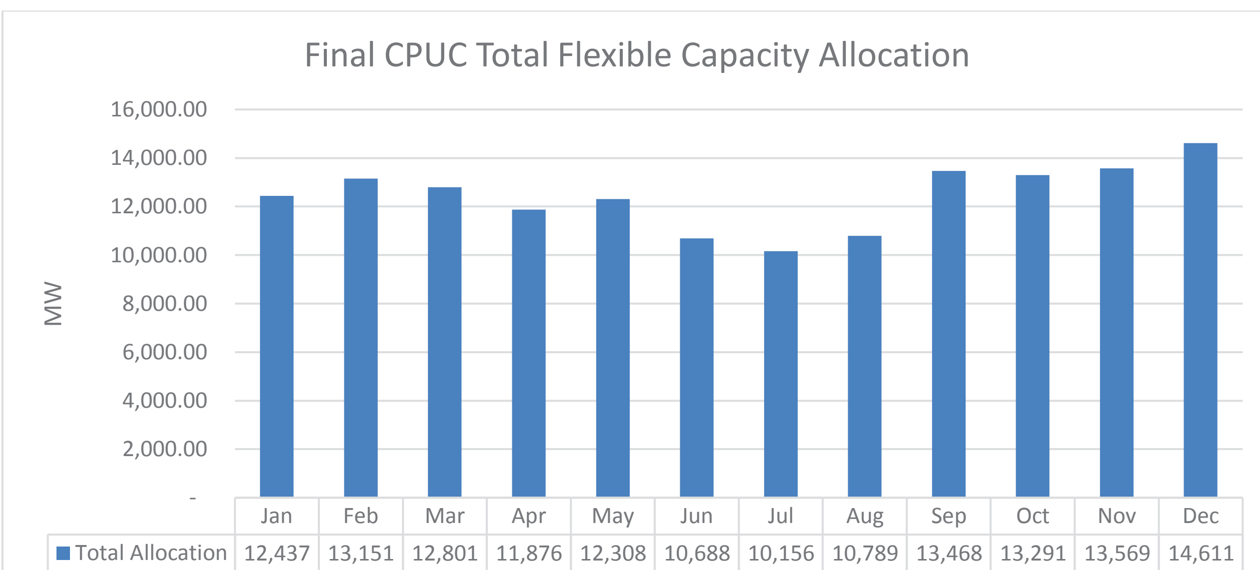
14 Because the Energy Division proposal states that the CPUC will allocate flexible capacity requirements to its jurisdictional LSEs based on peak load ratio share, the ISO has not calculated the individual contribution of each LSE.

15 Because of the geographic differences in the output, at some times one LRA's resources could be reducing the net-load ramp while another's could be increasing it.

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

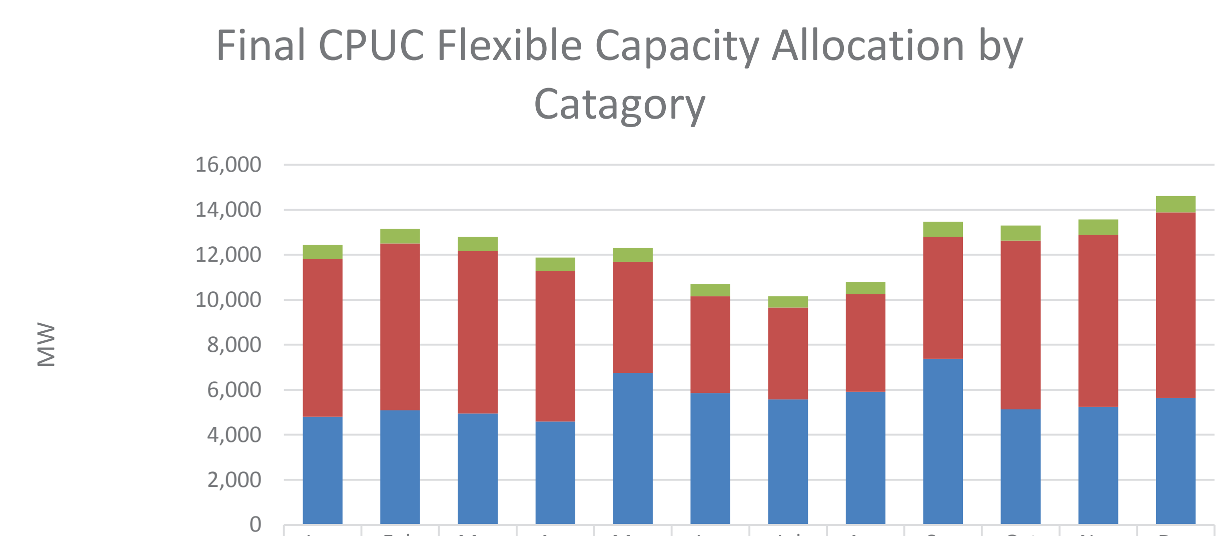
	Δ Load MW	Δ PV Fixed MW	Δ BTM Solar MW	Δ Wind MW	Net Load Allocation MW	3.5% expected peak load* Peak load ration share 2018	Total Allocation
Jan	4,584	-6,292	-590	56	11,410	1,027	12,438
Feb	4,595	-6,666	-602	-293	12,158	993	13,151
Mar	3,981	-6,808	-933	-97	11,820	981	12,801
Apr	2,689	-7,226	-982	73	10,824	1,052	11,876
May	1,849	-7,824	-851	-612	11,137	1,171	12,308
Jun	879	-7,414	-951	-120	9,366	1,322	10,688
Jul	548	-7,159	-1,066	51	8,722	1,433	10,156
Aug	1,335	-7,697	-1,181	877	9,337	1,452	10,790
Sep	2,180	-8,547	-1,297	-3	12,029	1,439	13,469
Oct	2,627	-7,742	-1,321	-405	12,097	1,193	13,291
Nov	3,585	-7,457	-1,321	-182	12,546	1,023	13,570
Dec	5,766	-6,510	-851	-416	13,545	1,066	14,612

Figure 7: CPUC Jurisdictional LSEs' Contribution to Flexible Capacity Needs



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	622	658	640	594	615	534	508	539	673	665	678	731
Peak Flexibility	7,010	7,413	7,215	6,694	4,946	4,295	4,081	4,336	5,413	7,491	7,648	8,236
Base Flexiblity	4,806	5,081	4,946	4,589	6,746	5,858	5,567	5,914	7,383	5,135	5,243	5,646

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: 2018 Forecasted 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				15	14		
March					12	19	
April					2	16	12
May			1		2	13	15
June			1		1	22	6
July	1	2			5	23	
August			1	1	21	7	
September	1		1	4	17	7	
October				6	23	2	
November				25	5		
December			1	29	1		

Frequency of Top Five Three Hour Net Load Ramp Start Hour ramp Start

	13:00	14:00	15:00	16:00	17:00
January		5			
February		5			
March			3	2	
April				4	1
May	1			3	1
June				2	3
July				5	
August			4	1	
September			3	2	
October		1	4		
November		5			
December		5			

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 the five-hour period of 3:00 p.m. to 8:00 p.m. for May through September, and 2:00 p.m. to 7:00 p.m. for January through April and October through December. The hours for January through April and October through December are one hour early than the hours established in the 2017 assessment. However, the summer hours are much later than the 2017 hours. 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 2019 in late 2017. At that time, the ISO will host a stakeholder meeting to discuss potential enhancements needs assessment methodology as identified in stakeholder comments and in this final paper. Specifically, 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.

10. Appendix

<u>**Summary of PG&E comments and replies**</u>

1. **CAISO should include the shaped AAEE profile, if possible, in its final study.**

   The ISO relies on the CEC for this data, at this time we still do not have the CEC AAEE profiles. Due to the tariff deadlines and analysis needed we are unable to incorporate the data this year.

2. **CAISO should reconcile and provide an explanation for data discrepancies in the net load data worksheet. Specifically, CAISO should provide an explanation for how solar thermal has been treated in the study and indicate if there has been an error in the data. In addition, there is missing data for solar PV beginning on August 5 at 9:29 and continuing through August 6 at 3:41; this missing data should be explained.**

   This is a misunderstanding. The overall wind capacity modeled this year included approximately 1,200 MW of additional dynamically scheduled out-of-state wind. The Solar thermal output was included in the overall solar profiles. The missing data on August 5 was due to the lack of telemetry and did not impact the 3-hour flexible capacity needs.

3. **The methodology to calculate flexible capacity needs should take into account the bidding behavior of those resources. Solar and wind resources that offer economic bids should not be modeled as must-take resources.**

   The intent of the analysis is to show the monthly flexible capacity needs. Since historical bidding behavior is not a guaranteed of future behavior the CAISO believes than individual BAs would be in a better position to determine whether to use curtailable wind/solar to meet its flexible capacity needs.

4. **PG&E suggests CAISO use other data sources at its disposal (such as the Master File and/or data reported on its own website) to check for accuracy and coverage of data reported by LSEs.**

   We appreciate the feedback above, and will continue to work towards providing more clarity to assist with the value differences. For the purposes of this study, the 14,220 MW value came from the survey responses from the LSEs.

5. **Suggestions for future metrics.**

   a. **CAISO could create a new metric that provides a simple metric that correlates installed capacity of a resource with its contribution to the flexible capacity requirement.**

      We appreciate the feedback and will take it into consideration in future iterations of the process.

b. **CAISO clearly indicates the forecasted flexible capacity need; another useful data point to include would be the existing flexible supply for comparison purposes.**

While not perfect measure, the previous year's Effective Flexible Capacity List is available at http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

c. **Shift Must Offer Obligation hours in March and April an hour later to better match the pattern of net load ramps.**

The CAISO understands that such a change could be justified. The ISO does not believe sufficient evidence exists to make this change for the 2018 assessment. However, if this trend continues, the ISO will consider the change in future assessment

6. **Additional clarifications are also requested.**

a. **Clarify whether the resource capacity in Table 1 is dependable capacity or installed capacity.**

It is installed capacity.

b. **CAISO should clarify if this data included any curtailment due to market signals or if the data was 2016 non-curtailed generation**.

The minute-by-minute wind and solar analysis include curtailments. The ISO excluded curtailments because curtailments typically occur before the hours of maximum ramping needs.

Summary of CEERT comments and replies

CEERT seeks additional clarity regarding an assessment of what resources have been used to meet flexible RA requirements. Specifically, CEERT sites to the use of imports dispatched through the ISO's day-ahead and real-time markets to address even ramps. By contrast, import resources are not currently eligible to provide flexible resource adequacy capacity. Based on this assessment, CEERT requests that the ISO reexamine the criteria used to determine flexible capacity eligibility criteria.

The ISO acknowledges the comments made by CEERT. However, these suggestion appear to be more appropriately addressed in the Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2. The ISO looks forward to CEERT's participation in that initiative.

ATTACHMENT B

2018
LOCAL CAPACITY TECHNICAL ANALYSIS
May 1, 2017

California ISO

2018 LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT AND STUDY RESULTS

May 1, 2017

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2018 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2018 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2016. On balance, the assumptions, processes, and criteria used for the 2018 LCT Study mirror those used in the 2007-2017 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 2018 LCT study results are provided to the CPUC for consideration in its 2018 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, 2017-2027 developed by the CEC; namely the mid-demand baseline with low additional achievable energy efficiency (AAEE), re-posted on 2/27/2017: http://www.energy.ca.gov/2016_energypolicy/documents/2016-12-08_workshop/LSE-BA_Forecasts.php.

---

[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 2018 vs. 2017 total LCR:

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**

2017 Local Capacity Requirements

	Qualifying Capacity			2017 LCR Need Based on Category B***			2017 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	20	198	218	110	0	**110**	157	0	**157**
North Coast / North Bay	128	722	850	721	0	**721**	721	0	**721**
Sierra	1176	890	2066	1247	0	**1247**	1731	312*	**2043**
Stockton	149	449	598	340	0	**340**	402	343*	**745**
Greater Bay	1070	8792	9862	4260	232*	**4492**	5385	232*	**5617**
Greater Fresno	231	3072	3303	1760	0	**1760**	1760	19*	**1779**
Kern	60	491	551	137	0	**137**	492	0	**492**
LA Basin	1615	8960	10575	6873	0	**6873**	7368	0	**7368**
Big Creek/ Ventura	543	4920	5463	1841	0	**1841**	2057	0	**2057**
San Diego/ Imperial Valley	239	5071	5310	3570	0	**3570**	~~3570~~**** 4635	0	**~~3570~~**** 4635**
Total	5231	33565	38796	20859	232	**21091**	~~23643~~	906	**~~24549~~**

* 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.
****In the 2017 LCR report, the San Diego-Imperial Valley study and the LA Basin-San Diego overall study had inconsistent assumptions regarding LA Basin resources, resulting in lower LCR value reported for the overall San Diego-Imperial Valley LCR area (3,570 MW). This value should have been reported as 4,635 MW based on the 2017 LCR requirements for the LA Basin and San Diego subarea.

Overall, the LCR needs have increased by about 660 MW or about 2.7% from 2017 to 2018. Based on the corrected 2017 LCR requirement for San Diego-Imperial Valley, the LCR needs have actually decreased by about 400 MW or about 1.5%.

The LCR needs have decreased in the following areas: Kern due to downward trend for load; North Coast/North Bay and Bay Area due to downward trend for load and new transmission projects and Stockton due to new transmission project. The LCR needs have increased in Sierra, Fresno and Big Creek/Ventura due to load increase; Humboldt due to new limiting contingency; LA Basin due to change in assumptions regarding Aliso Canyon.

San Diego/Imperial Valley technical requirements are going down since the correct 2017 LCR need should have been 4635 MW (with Aliso Canyon). Last year the San Diego-Imperial Valley study and the LA Basin-San Diego overall LCR studies had inconsistent assumptions regarding LA Basin resources, it used Aliso Canyon restriction for LA Basin-San Diego, however it did not used the same restriction in the San Diego-Imperial Valley area study. The 2017 misalignment gives the appearance that the San Diego-Imperial Valley needs are actually going up between the two years. Particular attention should also be paid to the sensitivities discussed in section IV.C.10 beginning on page 63.

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 2018 and 2017 LCRs.

Table of Contents

I. Executive Summary 1

II. Study Overview: Inputs, Outputs and Options 5

A. Objectives 5
B. Key Study Assumptions 5
1. Inputs and Methodology 5
C. Grid Reliability 7
D. Application of N-1, N-1-1, and N-2 Criteria 8
E. Performance Criteria 8
F. The Two Options Presented In This LCT Report 15
1. Option 1- Meet LCR Performance Criteria Category B 15
2. Option 2- Meet LCR Performance Criteria Category C and Incorporate Suitable Operational Solutions 16

III. Assumption Details: How the Study was Conducted 17

A. System Planning Criteria 17
1. Power Flow Assessment: 18
2. Post Transient Load Flow Assessment: 19
3. Stability Assessment: 19
B. Load Forecast 19
1. System Forecast 19
2. Base Case Load Development Method 20
C. Power Flow Program Used in the LCT analysis 21

IV. Local Capacity Requirement Study Results 22

A. Summary of Study Results 22
B. Summary of Zonal Needs 24
C. Summary of Results by Local Area 26
1. Humboldt Area 26
2. North Coast / North Bay Area 28
3. Sierra Area 31
4. Stockton Area 35
5. Greater Bay Area 39
6. Greater Fresno Area 45
7. Kern Area 49
8. LA Basin Area 51
9. Big Creek/Ventura Area 60
10. San Diego-Imperial Valley Area 63
11. Valley Electric Area 74

V. Appendix A – List of physical resources by PTO, local area and market ID 75

VI. Appendix B – Effectiveness factors for procurement guidance 128

II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the previous annual LCT Studies, the intent of the 2018 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 2018 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 2018 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2016.

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 2018 LCT Study:

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

Issue:	How are they incorporated into this LCT study:
Input Assumptions:	
• 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
Methodology:	
• 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.
Performance Criteria:	
• 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.
Load Pocket:	
• 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 2018 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. LCR Performance Criteria- Category B

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."

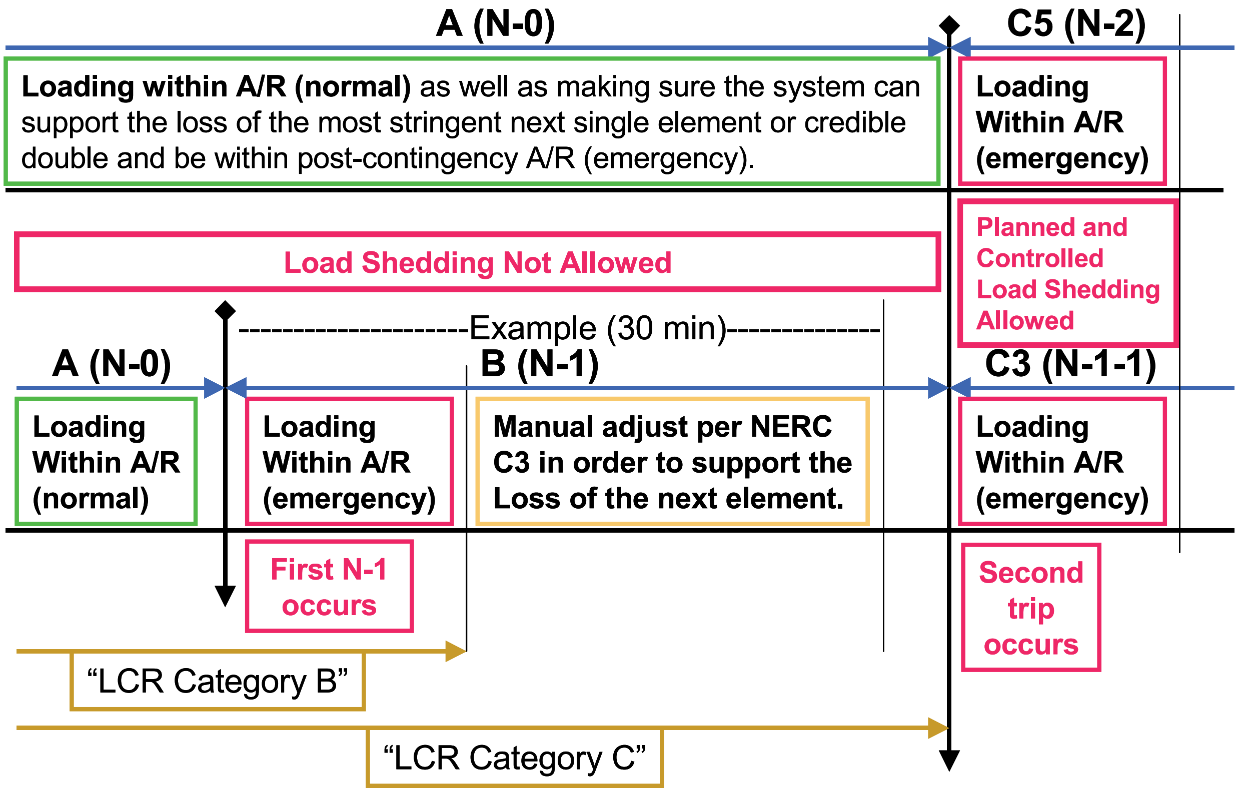
c. <u>CAISO Statutory Obligation Regarding Safe Operation</u>

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 19.0 and PowerGem's Transmission Adequacy and Reliability Assessment (TARA) program version 870. 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: 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%**

Table 6: 2017 Local Capacity Needs vs. Peak Load and Local Area Resources

	2017 Total LCR (MW)	Peak Load (1 in10) (MW)	2017 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2017 LCR as % of Total Area Resources
Humboldt	157	188	84%	218	72%
North Coast/North Bay	721	1311	55%	850	85%
Sierra	2043	1757	116%	2066	99%**
Stockton	745	1157	64%	598	125%**
Greater Bay	5617	10477	54%	9862	57%**
Greater Fresno	1779	2964	60%	3303	54%**
Kern	492	1139	43%	551	89%
LA Basin	7368	18890	39%	10575	70%
Big Creek/Ventura	2057	4719	44%	5463	38%
San Diego/Imperial Valley	3570	4840	74%	5310	67%
Total	**24549**	**47442***	**52%***	**38796**	**63%**

* 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 6/1/2018 have been included in this 2018 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, “2018 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, “2018 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	26306	3946	-7614	-3750	**18888**
NP26=NP15+ZP26	21002	3150	-3696	-2902	**17554**

Where:

<u>Load Forecast</u> is the most recent 1 in 2 CEC forecast for year 2018 - California Energy Demand Updated Forecast, 2017 - 2027, Mid Demand Baseline, Mid AAEE Savings dated February 27, 2017.

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

<u>Allocated Imports</u> are the actual 2017 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2018 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 down in Southern California by about 960 MW and up in Northern California by about 300 MW.
- The Import Allocations went up in Southern California by about 200 MW and down in Northern California by about 550 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 2017. 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

Area Definition:

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

Load:

Total 2018 busload within the defined area: 184 MW with -8 MW of AAEE and 11 MW of losses resulting in total load + losses of 187 MW.

List of physical units: See Appendix A.

Major new projects modeled:

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 169 MW in 2018 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 121 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 2017 the total load forecast has decreased by 1 MW and the LCR needs have increased by 12 MW due to different limiting contingency.

Humboldt Overall Requirements:

2018	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	14	196	210

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	121	0	121
Category C (Multiple)[10]	169	0	169

[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 2018 busload within the defined area: 1407 MW with -27 MW of AAEE, -79 MW of NTM-PV, and 32 MW of losses resulting in total load + losses of 1333 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.

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

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 209 MW in 2018 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 191 MW in 2018.

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), which was previously normally open at Cotati Substation. If the Lakeville #2 60 kV line is open, the limiting element is Santa Rosa-Corona 115 kV line and there is no additional LCR need beyond what is needed for the Eagle Rock sub-area. This limiting contingency establishes a LCR of 430 MW in 2018 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 634 MW in 2018 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 titled Lakeville.

Changes compared to last year's results:

The 2018 load forecast went up by 22 MW compared to the 2017 and total LCR need went down by 87 MW mainly due to load decrease in the Bay Area.

North Coast/North Bay Overall Requirements:

2018	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	5	113	751	869

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	634	0	634
Category C (Multiple)[12]	634	0	634

[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 2018 busload within the defined area: 1862 MW with -30 MW of AAEE, -107 MW of BTM-PV and 93 MW of losses resulting in total load + losses of 1818 MW.

List of physical units: See Appendix A.

Major new projects modeled: None.

Critical Contingency Analysis Summary:

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 78 MW (includes 48 MW of deficiency) in 2018 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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 85 MW in 2018 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 82 MW in 2018.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Pease Sub-area

The most critical 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 101 MW in 2018 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.

Bogue Sub-area

No requirement due to the Palermo-Rio Oso reconductoring project.

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-Brighton 230 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 787 MW (includes 47 MW of deficiency) in 2018 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 446 MW in 2018.

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 2018 a LCR of 575 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 2018 a LCR of 347 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 1625 MW (includes 196 MW of deficiency) in 2018 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 2018 a LCR of 1215 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 2018 a LCR of 1826 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 up by 61 MW and the LCR need has increased by 70 MW due to load increase.

Sierra Overall Requirements:

2018	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	57	1119	949	2125

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1215	0	1215
Category C (Multiple)[14]	1826	287	2113

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

[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.

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:

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

<u>Load:</u>

Total 2018 busload within the defined area: 1213 MW with -26 MW of AAEE, -38 MW of BTM-PV, and 20 MW of losses resulting in total load + losses of 1169 MW.

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

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

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 158 MW in 2018 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 620 MW (includes 276 MW of deficiency) in 2018 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 514 MW (includes 276 MW of deficiency) in 2018.

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 2018 local capacity need of 344 MW.

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Schulte #1 115 kV line and the loss of the GWF Tracy unit #3. The area limitation is thermal overload of the Tesla-Schulte #2 115 kV line. This single contingency establishes a local capacity need of 358 MW in 2018.

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 Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2018 local capacity need of 68 MW (including 45 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

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 31 MW in 2018 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 12 MW. The overall requirement for the Stockton area decreased by 26 MW mainly due to decrease in deficiency resulting from new transmission project.

Stockton Overall Requirements:

2018	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	16	123	466	605

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	358	0	358
Category C (Multiple)[16]	398	321	719

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

[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.

8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
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

<u>Load:</u>

Total 2018 bus load within the defined area is 10,309 MW with -207 MW of AAEE, -328 MW of Behind the meter DG, 209 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 10,247 MW. The expanded Bay Area also includes Moss Landing area load according to the Area Definition as delineated above.

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

Major new projects modeled:

1. NRS-Scott #1 115 kV line reconductoring
2. A few small renewable resources
3. Pittsburg Power Plant retirement
4. Moss Landing Units 6 & 7 retirement

Critical Contingency Analysis Summary:

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the Moraga – Claremont #1 or #2 115 kV line. This limiting contingency establishes a LCR of 56 MW in 2018 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The Oakland resources are required in order to meet local reliability requirements in the Oakland sub-area based on actual real-time data that shows a need of at least 98 MW for a 1 in 3 heat wave (2015/16). Further, the real-time data also showed that at times all three Oakland generators are on-line simultaneously in order to maintain local reliability. The local capacity technical study was intended to model a 1 in 10 heat wave resulting in an increased local capacity need beyond that observed in real-time. The discrepancy is due to load forecast distribution among substations in the area. ISO will work with PG&E and CEC to correct this discrepancy in future base cases.

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 well as voltage drop (5%) at the Morgan Hill substation. 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 105 MW in 2018 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 Metcalf-Evergreen #2 115 kV Line overlapped with Metcalf-El Patio #1 or #2 115 kV Line. The area limitation is thermal overloading of the Metcalf-Evergreen #1 115 kV Line. This limiting contingency establishes a LCR of 488 MW in 2018 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 2221 MW in 2018 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:

For thermal overloads, resources in the Moss Landing area are more effective than the resources in the South Bay. For voltage support, resources in the South Bay are more effective than the resources in the Moss Landing area. Minimum requirement assumes at least two blocks of Combined Cycle at Moss Landing.

Pittsburg and Oakland Sub-area Combined

No requirement is identified in this sub-area

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 1063 MW in 2018 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 and Pittsburg Sub-areas Combined

The two most critical contingencies listed below together establish a local capacity need of 2412 MW in 2018 as follows: 634 MW in NCNB and 1778 MW in the Bay Area with 596 MW in Ames and 1182 MW in Pittsburg as the minimum capacity necessary for reliable load serving capability within these sub-areas.

The most critical contingency in the Bay Area is an outage of DCTL Newark-Ravenswood & Tesla-Ravenswood 230 kV. The area limitation is thermal overloading of Newark-Ames #1, #2, #3 and Newark- Ames Distribution 115 kV lines.

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:

Resources must satisfy both constraints simultaneously, therefore no effectiveness factor is provided. 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 5160 MW in 2018 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 3910 MW in 2018.

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 2017 the load forecast is down by 230 MW compared with the physically defined Bay Area. The LCR has decreased by 457 MW due to the lower load forecast and new transmission projects.

Bay Area Overall Requirements:

2018	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	320	277	411	6095	7103

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	3910	0	3910
Category C (Multiple)[18]	5160	0	5160

[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.

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

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta 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:

2018 total busload within the defined area is 3189 MW with -46 MW of AAEE, 101 MW of losses and -139 MW DG resulting in a total (load plus losses) of 3290 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. A few new renewable resources were added.

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 150 MW in 2018 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 28 MW in 2018 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 18 MW in 2018 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 19 MW in 2018 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-Manchester 115 kV lines. This contingency could thermally overload the Herndon-Barton 115 kV line. This limiting contingency established an LCR of 880 MW in 2018 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 425 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) Wilson-Gregg 230 kV line and Borden-Gregg 230 kV line. This contingency would thermally overload the Panoche-Oro Loma 115 kV line. This limiting contingency establishes a LCR of 2081 MW in 2018 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 1949 MW in 2018.

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 increased by 326 MW and the LCR by 302 MW.

Fresno Area Overall Requirements:

2018	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	48	316	3215	3579

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	1949	0	1949
Category C (Multiple) [20]	2081	0	2081

[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

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-Charca 115 kV Line (Normal Open)
5) Wasco-Famoso 70 kV Line (Normal Open)
6) Maricopa-Copus 70 kV Line (Normal Open)
7) Copus-Old River 70 kV Line (Normal Open)
8) Kern Canyo-Magunden-Weedpatch 70 kV Line (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) Charca 115kV is out Famoso 115 kV is in
5) Wasco 70 kV is out Mc Farland 70 kV is in
6) Basic School Junction 70 kV is out, Copus 70 kV is in
7) Lakeview 70 kV is out, San Emidio Junction 70 kV is in
8) Magunden Junction 70 kV is out, Magunden 70 kV is in
9) Wheeler Ridge 115 kV is out, Adobe Solar 115 kV is in

Load:

2018 total busload within the defined area is 907 MW with -13 MW of AAEE, 7 MW of losses and -34 MW DG resulting in a total (load plus losses) of 867 MW.

List of physical units: See Appendix A.

Major new projects modeled:

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

a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

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

West Park Sub-area

No requirement due to decrease in load forecast.

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. This limiting contingency establishes a LCR of 133 MW in 2018 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.

South Kern PP Sub-area

The South Kern PP sub-area requirement is smaller than the Kern Oil sub-area therefore the need is already satisfied by resources located in the Kern Oli sub-area.

South Kern 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. This limiting contingency establishes a LCR of 453 MW in 2018 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.
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 down by 272 MW and The LCR requirement has decreased by 39 MW. The downward shift in load also resulted in the elimination of the

Westpark sub-area.

Kern Area Overall Requirements:

2018	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	15	551	566

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [21]	0	0	0
Category C (Multiple) [22]	453	0	453

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

[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.

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
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 2018 1-in-10 heat wave peak load modeled within the electrically defined area[23] includes 18,215 MW net managed peak load with 146 MW of peak shift, 22 MW pump load and 83 MW of losses resulting in total net load + losses + pumps with peak shift of 18,466 MW. The electrically defined LA Basin LCR area does not include Saugus substation load, which is 755 MW. When this load is added to the electrically defined LA Basin load, the total geographically-defined LA Basin load is 19,221 MW, which correlates with the CEC's Mid Demand Baseline with Low AAEE Savings with peak shift forecast for 2018.

List of physical units: See Appendix A.

Major new projects modeled:

1. San Luis Rey (2-225 MVAR), San Onofre (1-240 MVAR), Miguel (2-225 MVAR) and Santiago (3-81 MVAR) synchronous condensers
2. Imperial Valley Phase Shifting Transformers (230/230kV 2x400 MVA)
3. Huntington Beach Units 3 & 4 synchronous condensers retired at the end of 2017

[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.

4. Encina Unit 1 retired at the end of Q1 2017 (to allow generation interconnection related works for the new Carlsbad Energy Center); Carlsbad Energy Center's in-service date is delayed until Q4 2018.
5. Sycamore – Penasquitos 230 kV transmission line

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 would cause voltage collapse. This limiting contingency establishes an LCR of 227 MW in 2018 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units have the same effectiveness factor.

Western Sub-Area:

The most critical contingency for the Western 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 would result in thermal overload of the remaining Serrano – Villa Park 230 kV line. This limiting contingency establishes an LCR of 3,621 MW in 2018 as the resource capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

See Appendix B - Table titled Western LA Basin.

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 numerous 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 two most limiting contingencies for the Eastern LA Basin subarea are the following:

The thermal loading concern is caused by an overlapping contingency of the Palo Verde – Colorado River 500 kV line, system readjustment, then followed by Serrano – Valley 500 kV line or vice versa. This overlapping contingency could result in an overloading concern on the Iron Mountain – Eagle Mountain 230 kV line. The limiting contingency establishes an LCR need of 2,361 MW in 2018 as the resource capacity necessary for reliable load serving capability within this sub-area.

The post-transient voltage instability concern is caused by an overlapping contingency of Serrano – Valley 500 kV line, system readjustment, followed by a simultaneous N-2 of the Devers – Red Bluff 500 kV lines. The voltage instability concern requires the same amount of LCR need as in the thermal constraint discussed above.

Effectiveness factors:

Resources must satisfy both constraints simultaneously, therefore no effectiveness factor is provided.

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:

This sub-area has been eliminated due to the new Paloverde-Delaney-Colorado River 500 kV lines.

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.*

An additional consideration is whether the Aliso Canyon gas storage constraint needs to be evaluated to determine the LCR needs for the LA Basin and the San Diego-Imperial Valley for 2018. At this time, the ISO is not performing analyses that would involve balancing resources between the LA Basin and San Diego areas similar to the 2017 LCR due to the benefits of the enhanced balancing rules as the CPUC has recognized the effectiveness of tighter non-core balancing rules. Based on the recent CPUC Public Utilities Code Section 715 report[24], dated January 17, 2017, on page 15, the CPUC indicated that the 150 mmcf potential imbalance has been offset by the new balancing

---

24 http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AlisoGas1-9-715.pdf

rules and directly reduces the amount of the original curtailment identified in the four summer technical scenarios involving various levels of gas facility outages. However, as Southern California Gas Company has informed the CPUC in its February 17, 2017 Storage Safety Enhancement Plan, it is important to note that there are potential deliverability impacts due to tubing flow only operation of the remaining gas storage fields at Goleta, Playa Del Rey and Honor Rancho. More study is necessary to understand the meaning and the extent of the tubing only production limitation.

As mentioned above, the overall LA Basin-San Diego-Imperial Valley LCR needs were determined by evaluating the LCR needs in the San Diego-Imperial Valley LCR area first, and then determining the LCR needs for the LA Basin. 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.

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 (Category C). This overlapping contingency could thermally overload the Imperial Valley – El Centro 230 kV line (i.e., the “S” line)[25]. This contingency establishes a total local capacity need of 4,032 MW in 2018 as the resource capacity necessary for reliable load serving capability within the overall San Diego – Imperial Valley area.

The corresponding LA Basin LCR need associated with this contingency and level of LCR need for the San Diego – Imperial Valley is 7,300 MW.

[25] 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.

2. *Overall LA Basin Area:*

As discussed earlier, to determine whether the aforementioned LCR need in the LA Basin is adequate for the LA Basin LCR area, the ISO performed contingency analyses in the LA Basin after the evaluation of the LCR need for the San Diego-Imperial Valley LCR. 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 Sylmar - Eagle Rock 230 kV line. This establishes a total local capacity need in LA Basin area of 7,525 MW in 2018 as the minimum resource capacity necessary for reliable load serving capability within this sub-area.

The overall combined LA Basin-San Diego-Imperial Valley area LCR need has a total of 11,557 MW in 2018 time frame as follows: 7,525 MW in the LA Basin and 4,032 MW in the 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 Sylmar – Eagle Rock 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.

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

Sensitivity assessment with Imperial Valley solar generation unavailable at 7 p.m. for a peak load day

The purpose of performing this sensitivity study was to evaluate the potential impact to the LCR requirements for the LA Basin-San Diego-Imperial Valley area for the scenario in which the Imperial Valley solar generation is unavailable to provide resource needs to mitigate loading concern on the Imperial Valley – El Centro 230 kV line under an overlapping G-1/N-1 contingency of the combined cycled TDM generation, system readjustment, followed by an outage on the Imperial Valley – North Gila 500 kV line. Since the solar generation in the Imperial Valley area are effective in mitigating this line overloading concern, its unavailability at the time of the area peak load at 7 p.m. could affect the LCR requirements in the overall LA Basin, San Diego subarea, and the overall San Diego – Imperial Valley area. This analysis is for risk assessment purposes. The existing practice is to establishing local capacity requirements for use in the resource adequacy (RA) process based on individual resource net qualifying capacity (NQC) as dictated by accounting rules of Local Regulatory Agencies (LRA).

For this sensitivity assessment, the ISO reviewed the availability of the solar central plants in the Imperial Valley area at 7 p.m. on September 26, 2016, using archived data from the ISO Energy Management System (EMS). This date had high loads for SDG&E in 2016. The Imperial Valley solar generation had either 0 MW output or was negligible (i.e., less than 1% of its maximum output which is within 2% tolerance of the archived real-time data). The study case was modified by reducing Imperial Valley solar generation from its NQC values to no output. The limiting contingency is the overlapping G-1/N-1 of TDM combined cycled generation, system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line. This contingency could cause an overloading concern on the Imperial Valley – El Centro 230 kV line. The LCR requirements for the combined LA Basin-San Diego-Imperial Valley area, based on this scenario are: LA Basin LCR needs at 7,604 MW and San Diego-Imperial Valley area LCR needs at 4,142 MW (including San Diego sub-area LCR needs at 3,145 MW).

The following are key observations when comparing the LCR needs of the sensitivity study to the LCR needs based on the currently established NQC values:

- With less solar generating resources being available in the Imperial Valley at 7 p.m., the next effective generating resources are located in the San Diego sub-area. This increases the San Diego sub-area LCR needs to 3,145 MW (an increase of about 750 MW as there are no further resources in the Imperial Valley area that can be dispatched, and the next available resources are located in the San Diego sub-area).
- The total LCR needs for the overall San Diego – Imperial Valley area increase to 4,142 MW, representing an increase of 101 MW as less effective generating

resources in the San Diego sub-area are dispatched due to unavailability of more effective solar generation at 7 p.m. timeframe.

- The LA Basin LCR needs were increased slightly by about 79 MW, with the same reason for the increase as in the second bullet discussion above.

Please refer to section IV.C.10 for further discussion of the San Diego – Imperial Valley local capacity requirements.

<u>Changes compared to last year's results:</u>

Compared with 2017, the latest CEC-adopted adjusted peak demand forecast for 2018 is reduced by 627 MW for geographic LA Basin and reduced by 424 MW based on the electrical definition. The LCR need has increased by 157 MW, mainly due to change in assumptions regarding the Aliso Canyon gas storage constraint (used in 2017 and not in 2018) see discussion above.

<u>LA Basin Overall Requirements:</u>

2018	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	Preferred Res. (MW)	20 Min. DR (MW)	Mothball (MW)	Max. Qualifying Capacity (MW)
Available generation	321	59	1176	8279	144	321	435	10735

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[26]	6,873	0	6,873
Category C (Multiple)[27]	7,525	0	7,525

[26] 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.

[27] 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.

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
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 2018 busload within the defined area[28] is 4,661 MW with (108) MW of AAEE, (169) MW[29] of BTM PV impact, 51 MW of losses and 369 MW of pumps resulting in total net managed load + losses + pumps of 4,802 MW.

List of physical units: See Appendix A.

Major new projects modeled: None

[28] The Big Creek Ventura LCA includes the Saugus Substation.
[29] The BTM PV impact value includes a downward adjustment by 68 MW due to peak shift.

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

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 515 MW in 2018 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

See Appendix B - Table titled Rector.

Vestal Sub-area

The most critical contingency for the Vestal sub-area is 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. This limiting contingency establishes a LCR of 848 MW in 2018 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 250 MW in 2018 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

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 504 MW in 2018 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

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 2,321 MW in 2018 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 2,023 MW in 2018.

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 2017 the load forecast is up by 83 MW and the LCR need has increased by 264 MW.

Big Creek Overall Requirements:

2018	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	58	372	5227	5657

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[30]	2023	0	2023
Category C (Multiple)[31]	2321	0	2321

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

[30] 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.

[31] 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) Imperial Valley is in El Centro is out
9) Imperial Valley is in La Rosita is out

Load:

The CEC-adopted demand forecast for 2018 from the 2017-2027 Mid Baseline, Low AAEE savings for 1-in-10 heat wave forecast is 4,786 MW[32] (this is the net value that includes loads, 125 MW of losses and 81 MW AAEE). The total adjusted demand after including 138 MW peak shift adjustment modeled in the study is 4,924 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. 2nd Encina 230/138 bank #61
2. Encina power plant unit #1 retirement
3. TL6906 Mesa Rim rearrangement
4. Salt Creek 69 kV substation
5. Vine 69 kV substation
6. Bay Boulevard 230 kV substation
7. Sycamore - Penasquitos 230 kV line (In-service by June 30, 2018)
8. Imperial Valley phase shifting transformers
9. Miguel synchronous condensers (2x225 Mvar)
10. San Luis Rey synchronous condensers (2x225 Mvar)
11. San Onofre synchronous condenser (1x225 Mvar)
12. New capacitors at Pendlenton and Basilone 69 kV substations
13. Storage projects at Escondido (3x10 MW) and El Cajon (7.5 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

[32] CEC-adopted 2016 IEPR demand forecast for 2017-2027, March 2017, for Mid Demand Baseline Case with Low AAEE Savings.

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 75 MW in 2018 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 ISO approved three transmission projects (reconductoring of the Mission-Mesa Heights (TL676) and Kearny-Mission (TL663) 69 kV lines, and TL600 loop-in to Mesa Heights substation) in the 2010-2011 and 2015~2016 TPPs, which will ultimately eliminate local capacity requirement for the four remaining peaking units at Kearney in the Mission sub-area. Without these three projects in-service by the summer of 2018, the most critical contingency for the Mission sub-area was the loss of TL663 followed by the loss of TL676 or vice versa, which could thermally overload the Kearny-Clairmont Tap 69 kV line (TL600). This limiting contingency could establish an LCR of 28 MW in 2018 as the minimum generation capacity necessary for reliable load serving capability within this sub-area. However, the ISO concurred in SDG&E's proposal to implement a remedial action scheme (RAS) as an interim solution to eliminate the Mission LCR sub-area since SDG&E provided several reasons for needing the removal of the Kearny peakers[33]. The proposed Mesa Heights RAS will be in service by summer 2018 to mitigate the need for the Kearney peakers.

Esco Sub-area

The most critical contingency for the Esco sub-area is the loss of one of the two Sycamore-Pomerado 69 kV lines (TL6915 or TL6924) followed by the loss of Esco -

[33] In SDG&E's comments submitted on the draft 2018 Local Capacity Technical Report they provided information regarding the age and condition of the existing equipment and the need to expand the distribution facilities at Kearny Substation which supported the need to rebuild Kearny substation. This substation work requires that the four Kearny peaking generation units be removed by the end of 2017.

Escondido 69kV line (TL6908), which could thermally overload the remaining Sycamore-Pomerado 69 kV line. This limiting contingency establishes a LCR of 8 MW in 2018 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

It is recommended to retain 137 MW of generation resources in the sub-area, if the in-service date for Sycamore - Penasquitos 230 kV line project is expected to be later than June 1, 2018.

Effectiveness factors:
The only unit within this sub-area is needed so no effectiveness factor is required.

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 23 MW in 2018 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 50 MW in 2018 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

No local capacity requirement is identified in 2018 due to the Sycamore - Penasquitos 230 kV line project.

It is recommended to retain 38 MW of Miramar Energy Facility in the sub-area, if the in-service date for Sycamore - Penasquitos 230 kV line project is expected to be later than June 1, 2018.

Effectiveness factors:

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

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.*

An additional consideration is whether the Aliso Canyon gas storage constraint needs to be evaluated to determine the LCR needs for the LA Basin and the San Diego-Imperial Valley for 2018. At this time, the ISO is not performing analyses that would involve balancing resources between the LA Basin and San Diego areas similar to the 2017 LCR due to the benefits of the enhanced balancing rules as the CPUC has recognized the effectiveness of tighter non-core balancing rules. Based on the recent CPUC Public Utilities Code Section 715 report[34], dated January 17, 2017, on page 15, the CPUC indicated that the 150 mmcf potential imbalance has been offset by the new balancing rules and directly reduces the amount of the original curtailment identified in the four summer technical scenarios involving various levels of gas facility outages. However, as Southern California Gas Company has informed the CPUC in its February 17, 2017 Storage Safety Enhancement Plan, it is important to note that there are potential deliverability impacts due to tubing flow only operation of the remaining gas storage fields at Goleta, Playa Del Rey and Honor Rancho. More study is necessary to understand the meaning and the extent of the tubing only production limitation.

As mentioned above, the overall LA Basin-San Diego-Imperial Valley LCR needs were determined by evaluating the LCR needs in the San Diego-Imperial Valley LCR area first, and then determining the LCR needs for the LA Basin. 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.

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

34 http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AlisoGas1-9-715.pdf

(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 total local capacity need for of 4,032 MW in 2018 as the resource capacity necessary for reliable load serving capability within the overall San Diego – Imperial Valley area.

The corresponding LA Basin LCR need associated with this contingency and level of LCR need for the San Diego – Imperial Valley is 7,300 MW.

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 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.

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 the Ocotillo-Suncrest 500 kV line. The limiting constraint is the post-transient voltage instability, causing an LCR need of 2,157 MW in 2018 for the San Diego sub-area. The LCR need for the San Diego sub-area based on this 500 kV line N-1-1 contingency is smaller than the need determined in item #1 above. The addition of the synchronous condenser projects in Orange County and San Diego areas help mitigate this contingency which used to be the primary driver of LCR need for the San Diego sub-area.

3. Overall LA Basin Area:

As discussed earlier, to determine whether the aforementioned LCR need in the LA

Basin is adequate for the LA Basin LCR area, the ISO performed contingency analyses in the LA Basin after the evaluation of the LCR need for the San Diego-Imperial Valley LCR. 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 Sylmar - Eagle Rock 230 kV line. This establishes a total local capacity need in LA Basin area of 7,525 MW in 2018 as the minimum resource capacity necessary for reliable load serving capability within this sub-area.

The overall combined LA Basin-San Diego-Imperial Valley area LCR need has a total of 11,557 MW in 2018 time frame as follows: 7,525 MW in the LA Basin and 4,032 MW in the 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 Sylmar – Eagle Rock 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.

Sensitivity assessment with Imperial Valley solar generation unavailable at 7 p.m. for a peak load day

The purpose of performing this sensitivity study was to evaluate the potential impact to the LCR requirements for the LA Basin-San Diego-Imperial Valley area for the scenario in which the Imperial Valley solar generation is unavailable to provide resource needs to mitigate loading concern on the Imperial Valley – El Centro 230 kV line under an overlapping G-1/N-1 contingency of the combined cycled TDM generation, system readjustment, followed by an outage on the Imperial Valley – North Gila 500 kV line. Since the solar generation in the Imperial Valley area are effective in mitigating this line overloading concern, its unavailability at the time of the area peak load at 7 p.m. could affect the LCR requirements in the overall LA Basin, San Diego subarea, and the overall San Diego – Imperial Valley area. This analysis is for risk assessment purposes. The existing practice is to establishing local capacity requirements for use in the resource adequacy (RA) process based on individual resource net qualifying capacity (NQC) as dictated by accounting rules of Local Regulatory Agencies (LRA).

For this sensitivity assessment, the ISO reviewed the availability of the solar central plants in the Imperial Valley area at 7 p.m. on September 26, 2016, using archived data from the ISO Energy Management System (EMS). This date had high loads for SDG&E in 2016. The Imperial Valley solar generation had either 0 MW output or was negligible (i.e., less than 1% of its maximum output which is within 2% tolerance of the archived real-time data). The study case was modified by reducing Imperial Valley solar generation from its NQC values to no output. The limiting contingency is the overlapping G-1/N-1 of TDM combined cycled generation, system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line. This contingency could cause an overloading concern on the Imperial Valley – El Centro 230 kV line. The LCR requirements for the combined LA Basin-San Diego-Imperial Valley area, based on this scenario are: LA Basin LCR needs at 7,604 MW and San Diego-Imperial Valley area LCR needs at 4,142 MW (including San Diego sub-area LCR needs at 3,145 MW).

The following are key observations when comparing the LCR needs of the sensitivity study to the LCR needs based on the currently established NQC values:

- With less solar generating resources being available in the Imperial Valley at 7 p.m., the next effective generating resources are located in the San Diego sub-area. This increases the San Diego sub-area LCR needs to 3,145 MW (an increase of about 750 MW as there are no further resources in the Imperial Valley area that can be dispatched, and the next available resources are located in the San Diego sub-area).
- The total LCR needs for the overall San Diego – Imperial Valley area increase to 4,142 MW, representing an increase of 101 MW as less effective generating resources in the San Diego sub-area are dispatched due to unavailability of more effective solar generation at 7 p.m. timeframe.
- The LA Basin LCR needs were increased slightly by about 79 MW, with the same reason for the increase as in the second bullet discussion above.

Sensitivity assessment without the Sycamore – Penasquitos 230 kV line

This study is a sensitivity assessment showing the LCR needs without the Sycamore – Penasquitos 230 kV line. Currently this project is to be in service at the end of June, 2018, after the June 1, 2018 in-service date required by existing practice.

The Bay Blvd. Substation project was proposed to replace the existing South Bay Substation located approximately 0.5 miles to the north of the site of the new substation after the retirement of the once-through-cooled South Bay Power Plant.

With the addition of the new Bay Blvd. Substation, but without the new Sycamore – Penasquitos 230 kV transmission line in service, the ISO has identified the following overloading concern under a P6 (N-1-1) contingency of the Miguel – Miguel Tap – Bay Blvd. – Otay Mesa 230 kV line, followed by an outage of the Mission – Old Town Tap – Silvergate – Old Town 230 kV line. The reliability concerns occur as the loads previously served from the South Bay 138 kV transmission are transferred to the 230 kV transmission system serving Mission, Old Town, Silvergate and Bay Blvd. substations. Under the above mentioned P6 contingency conditions, the Miguel and Otay Mesa source for the Bay Blvd. Substation is removed, forcing power to flow on the remaining source to come from Mission Substation, overloading the remaining Mission-Old Town 230 kV line. This loading concern will be mitigated upon implementation of the Sycamore-Penasquitos 230 kV line, as this new line will provide a strong source to the Penasquitos and Old Town substations, relieving the overloading conditions on the Mission-Old Town 230 kV line. The following is a summary of the overloading conditions under this P6 (N-1-1) contingency.

1. With no dispatch of the Encina generation, the Mission – Old Town 230 kV line is loaded up to 137% of its line rating (the Mission – Old Town has the same rating under normal and emergency conditions) as a result of an overlapping N-1-1 outage of Miguel – Miguel Tap – Bay Blvd. – Otay Mesa 230 kV line, followed by an outage of the Mission – Old Town Tap – Silvergate – Old Town 230 kV line.

2. The above loading concern will be reduced to about 117% with the dispatch of entire Encina generation, system adjustment that includes implementation of all 20-minute “fast” demand response and all of battery energy storage with potential load curtailment impact of approximately 199 MW from three substations (i.e., Old Town, Pacific Beach and Sampson).

3. To mitigate the above loading concern, the following additional interim measure would need to be implemented as part of the system adjustment between the first and second contingency:

- Curtail 643 MW of generation from Otay Mesa and a small portion of Pio Pico to reduce the potential overloading concern on the Mission – Old Town 230 kV line upon the second N-1 contingency;
- With the generation curtailment above, the amount of load that would need to be curtailed is approximately 145 MW from Station "B" and Old Town Substation. This amount of load curtailment is the deficiency identified for the new Old Town sub-area.
- Dispatch all available resources in the San Diego sub-area.

The total LCR need for the San Diego – Imperial Valley area would be 4,308 MW, which includes an estimated 145 MW deficiency.

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 adjusted to changes in real time conditions and more specifically the shift of load to later hours of the day (6 or 7 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 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 2018 adjusted peak shift demand for the San Diego area is higher by about 84 MW when compared to last year study. The overall LCR needs for the San Diego-Imperial Valley are increased over the reported 2017 LCR value (3,570 MW) by 462 MW. However in the 2017 LCR report, the San Diego-Imperial Valley study and the LA Basin-San Diego overall study had inconsistent assumptions regarding LA Basin

[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.

resources, resulting in lower LCR value reported for the San Diego-Imperial Valley LCR area (3,570 MW). This value should have been 4,635 MW based on the lower LA Basin generation dispatch associated with the Aliso Canyon gas storage constraint scenario used for the 2017 LCR study. Using this value for comparison, the 2018 LCR need for the San Diego-Imperial Valley area would have been reduced by 603 MW.

<u>San Diego-Imperial Valley Area Overall Requirements:</u>

2018	QF (MW)	Wind (MW)	Market (MW)	Battery St. (MW)	20 minute DR (MW)	Max. Qualifying Capacity (MW)
Available generation	104	98	4656	38	19	4915

2018	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[36]	4032	0	4032
Category C (Multiple)[37]	4032	0	4032

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

[36] 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.

[37] 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.

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	23.80	1	Bay Area	Oakland		MUNI
PG&E	ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	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	37.71	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	23.38	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	8.86	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO1	32176	SHILOH	34.5	48.20	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	40.62	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	23.03	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	35.20	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	200.80	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG2	33188	MARSHCT2	16.4	199.90	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG3	33189	MARSHCT3	16.4	199.50	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG4	33189	MARSHCT4	16.4	201.40	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	CONTAN_1_UNIT	36856	CCA100	13.8	27.70	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	MUNI
PG&E	CROKET_7_UNIT	32900	CRCKTCOG	18	232.78	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	15.27	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	181.90	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33120	GATEWAY3	18	181.90	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33118	GATEWAY1	18	192.11	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	12.5	23.40	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	KELSO_2_UNITS	33813	MARIPCT1	13.8	47.45	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33815	MARIPCT2	13.8	47.45	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33817	MARIPCT3	13.8	47.45	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33819	MARIPCT4	13.8	47.45	4	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KIRKER_7_KELCYN				3.21		Bay Area	Pittsburg	Not modeled	Market
PG&E	LAWRNC_7_SUNYVL				0.16		Bay Area	None	Not modeled Aug NQC	Market
PG&E	LECEF_1_UNITS	35854	LECEFGT1	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35855	LECEFGT2	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35856	LECEFGT3	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35857	LECEFGT4	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35858	LECEFST1	13.8	113.85	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				1.94		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	METCLF_1_QF				0.00		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				0.01		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		Market
PG&E	MOSSLD_2_PSP1	36222	DUKMOSS2	18	163.20	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP1	36223	DUKMOSS3	18	183.60	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP2	36224	DUKMOSS4	18	163.20	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP2	36225	DUKMOSS5	18	163.20	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP2	36226	DUKMOSS6	18	183.60	1	Bay Area	South Bay-Moss Landing		Market
PG&E	NEWARK_1_QF				0.02		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	OAK C_1_EBMUD				1.51		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	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_7_BAYENV				2.00		Bay Area	None	Not modeled Aug NQC	Market
PG&E	RUSCTY_2_UNITS	35304	RUSELCT1	15	180.15	1	Bay Area	Ames	No NQC - Pmax	Market

PG&E	RUSCTY_2_UNITS	35305	RUSELCT2	15	180.15	2	Bay Area	Ames	No NQC - Pmax	Market
PG&E	RUSCTY_2_UNITS	35306	RUSELST1	15	237.09	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	0.52	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	STAUFF_1_UNIT	33139	STAUFER	9.11	0.07	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.00	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.00	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32923	CHEVGEN3	13.8	0.00	3	Bay Area	Pittsburg	Aug NQC	Market
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.95	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.95	2	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	3.77	3	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	UNCHEM_1_UNIT	32920	UNION CH	9.11	10.95	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.27	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.27	2	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.27	3	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	USWNDR_2_SMUD	32169	SOLANOWP	21	22.43	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD2	32186	SOLANO	34.5	43.15	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_UNITS	32168	EXNCO	9.11	4.00	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWPJR_2_UNITS	39233	GRNRDG	0.69	17.35	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	3.52	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZOND_6_UNIT	35316	ZOND SYS	9.11	1.52	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	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_LFC 51_2_UNIT 1	35310	PPASSWND	21	7.20	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	12.5	0.00	1	Bay Area	South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_NA	35861	SJ-SCL W	4.3	6.50	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_SEAWST_6_LAPOS	35312	FOREBAYW	22	4.30	1	Bay Area	Contra Costa	No NQC - est. data	Wind

PG&E	ZZ_SHELRF_1_UNITS	33141	SHELL 1	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_SHELRF_1_UNITS	33142	SHELL 2	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_SHELRF_1_UNITS	33143	SHELL 3	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
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	35622	SWIFT	115	4.00	BT	Bay Area	South Bay-Moss Landing	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	30524	0354-WD	230	1.83	EW	Bay Area	Contra Costa	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	35302	NUMMI-LV	12.6	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	35859	HGST-LV	12.4	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_GWFPW1_6_UNIT	33131	GWF #1	9.11	0.00	1	Bay Area	Pittsburg, Contra Costa	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW2_1_UNIT 1	33132	GWF #2	13.8	0.00	1	Bay Area	Pittsburg	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW3_1_UNIT 1	33133	GWF #3	13.8	0.00	1	Bay Area	Pittsburg, Contra Costa	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW4_6_UNIT 1	33134	GWF #4	13.8	0.00	1	Bay Area	Pittsburg, Contra Costa	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW5_6_UNIT 1	33135	GWF #5	13.8	0.00	1	Bay Area	Pittsburg	Retired	QF/Selfgen
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	1	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	1	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	1	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	12.5	0.00	1	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	AGRICO_6_PL3N5	34608	AGRICO	13.8	20.00	3	Fresno	Wilson, Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	2	Fresno	Wilson, Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	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_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	12.5	6.76	1	Fresno	Wilson	Aug NQC	Market
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	6.76	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	1.00	1	Fresno	Wilson, Coalinga	Aug NQC	QF/Selfgen
PG&E	CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.75	2	Fresno	Wilson, Coalinga	Aug NQC	QF/Selfgen
PG&E	CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	7.60	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				0.35		Fresno	Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
PG&E	CORCAN_1_SOLAR2				0.19		Fresno	Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
PG&E	CRESSY_1_PARKER	34140	CRESSEY	115	0.67		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	DINUBA_6_UNIT	34648	DINUBA E	13.8	7.59	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				1.27		Fresno	Wilson	Not Modeled Aug NQC	Market
PG&E	ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	7.22	1	Fresno	Wilson	Aug NQC	Market
PG&E	EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	94.50	1	Fresno	Wilson	Aug NQC	MUNI
PG&E	EXCLSG_1_SOLAR	34623	Q678	0.5	41.54	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	6.74	2	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	3.60	3	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.95	4	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY	12.5	3.24	1	Fresno	Wilson	Aug NQC	Market
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY	12.5	3.24	2	Fresno	Wilson	Aug NQC	Market
PG&E	GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Fresno	Wilson, Herndon, Hanford		Market
PG&E	GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	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	45.33	1	Fresno	Wilson		Market
PG&E	HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Fresno	Wilson		Market
PG&E	HENRTS_1_SOLAR	34617	Q581	0.38	80.34	1	Fresno	Wilson	Aug NQC	Market
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	6.79	1	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	6.79	2	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	INTTRB_6_UNIT	34342	INT.TURB	9.11	2.76	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	12.5	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	23.71	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, Reedley	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 Energy Only	Market
PG&E	KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	LEPRFD_1_KANSAS	34680	Q636	12.5	4.50	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	12.5	0.44	QF	Fresno	Wilson, Herndon	Aug NQC	QF/Selfgen
PG&E	MCSWAN_6_UNITS	34320	MCSWAIN	9.11	10.00	1	Fresno	Wilson	Aug NQC	MUNI

PG&E	MENBIO_6_RENEW1	34339	CALRENEW	12.5	4.02	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	3.50	1	Fresno	Wilson	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR1	34311	NORTHSTAR	0.2	50.90	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	24.10	1	Fresno	Wilson	Aug NQC	Market
PG&E	MSTANG_2_SOLAR3	34683	Q643W	0.8	32.14	1	Fresno	Wilson	Aug NQC	Market
PG&E	MSTANG_2_SOLAR4	34683	Q643W	0.8	24.10	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	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	55.58	1	Fresno	Wilson		Market
PG&E	PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	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	12.5	4.25	1	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	2.12	2	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	6.17	3	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	3.09	4	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	19.41	1	Fresno	Wilson	Aug NQC	Market

PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	4.66	2	Fresno	Wilson	Aug NQC	Market
PG&E	STOREY_2_MDRCH2				0.25		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH3				0.19		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	STOREY_7_MDRCHW	34209	STOREY D	12.5	0.00	1	Fresno	Wilson	Aug NQC	Net Seller
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.56	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.56	2	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	TRNQLT_2_SOLAR	34340	Q643X	0.8	160.69	1	Fresno	Wilson	Aug NQC	Market
PG&E	ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	23.92	1	Fresno	Wilson, Herndon	Aug NQC	QF/Selfgen
PG&E	VEGA_6_SOLAR1	34314	Q548	34.5	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	WAUKNA_1_SOLAR	34696	CORCORANPV_S	21	0.40	1	Fresno	Wilson, Herndon, Hanford	Aug NQC	Market
PG&E	WAUKNA_1_SOLAR2	34677	Q558	21	17.43	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	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	WRGHTP_7_AMENGY	34207	WRIGHT D	12.5	0.14	QF	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	ZZ_BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.00	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_NA	34485	FRESNOWW	12.5	0.00	1	Fresno	Wilson	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	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	34303	Q612	13.8	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	ZZZ_New Unit	34653	Q526	33	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	ZZZ_New Unit	34673	Q532	13.8	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	ZZZ_New Unit	34300	Q550	34.5	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	36205	Q648	34.5	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	39604	PATRIOTB	0.32	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	39601	PATRIOTA	0.32	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	34467	GIFFEN_DIST	12.5	10.00	1	Fresno	Wilson, Herndon	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34649	Q965	0.36	14.00	1	Fresno	Wilson, Herndon	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34644	Q679	0.48	20.00	1	Fresno	Wilson	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34335	Q723	0.32	50.00	1	Fresno	Wilson, Borden	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34688	Q272	0.55	125.00	1	Fresno	Wilson	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34603	JGBSWLT	12.5	0.00	ST	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	ZZZ_New Unit	34420	CORCORAN	115	19.00	WD	Fresno	Wilson, Herndon, Hanford	No NQC - Pmax	Market
PG&E	BRDGVL_7_BAKER				0.00		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 Energy Only	QF/Selfgen
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	0.00	1	Humboldt	None	Aug NQC	Net Seller
PG&E	LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	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	5.25	1	Humboldt	None	Aug NQC	QF/Selfgen
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	5.25	2	Humboldt	None	Aug NQC	QF/Selfgen
PG&E	PACLUM_6_UNIT	31153	PAC.LUMB	2.4	3.15	3	Humboldt	None	Aug NQC	QF/Selfgen
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	17.56	FW	Kern	South Kern PP, Kern Oil	Aug NQC	Market
PG&E	ADOBEE_1_SOLAR	35021	Q622B	34.5	18.42	1	Kern	South Kern PP	Aug NQC	Market
PG&E	BDGRCK_1_UNITS	35029	BADGERCK	13.8	44.00	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	BEARMT_1_UNIT	35066	PSE-BEAR	13.8	47.00	1	Kern	South Kern PP, West Park	Aug NQC	Net Seller
PG&E	BKRFLD_2_SOLAR1				1.20		Kern	South Kern PP	Not modeled Aug NQC	Market
PG&E	DEXZEL_1_UNIT	35024	DEXEL +	13.8	13.52	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	DISCOV_1_CHEVRN	35062	DISCOVRY	13.8	2.05	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	DOUBLC_1_UNITS	35023	DOUBLE C	13.8	51.60	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KERNFT_1_UNITS	35026	KERNFRNT	9.11	52.10	1	Kern	South Kern PP	Aug NQC	Net Seller

PG&E	KRNCNY_6_UNIT	35018	KERNCNYN	11	11.50	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR1	35019	REGULUS	0.4	52.75	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR3	35087	Q744G3	0.4	12.04	3	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR4	35059	Q744G2	0.4	21.42	2	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR5	35054	Q744G1	0.4	13.39	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.1	44.80	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	MTNPOS_1_UNIT	35036	MT POSO	13.8	31.12	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	OLDRIV_6_BIOGAS				1.38		Kern	South Kern PP	Not modeled Aug NQC	Market
PG&E	OLDRV1_6_SOLAR	35091	OLD_RVR1	12.5	16.67	1	Kern	South Kern PP	Aug NQC	Market
PG&E	RIOBRV_6_UNIT 1 3	35020	RIOBRAVO	9.1	0.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SIERRA_1_UNITS	35027	HISIERRA	9.11	52.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR1	35089	S_KERN	0.48	14.73	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR2	35069	Q885	0.36	8.03	1	Kern	South Kern PP	Aug NQC	Market
PG&E	VEDDER_1_SEKERN	35046	SEKR	9.11	12.47	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	ZZZ_New Unit	35092	Q744G4	0.38	25.46	1	Kern	South Kern PP	No NQC - est. data	Market
PG&E	ZZZZZZ_OILDAL_1_UNIT 1	35028	OILDALE	9.11	0.00	1	Kern	South Kern PP, Kern Oil	Retired	Net Seller
PG&E	ZZZZZZ_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				1.07		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				1.45		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				0.00		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	5.43	1	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	5.43	2	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	1.63	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	5.29	1	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	2.40	3	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	2.40	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	3.29	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	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				0.15		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				0.54		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	24.31	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	1.00		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	45.00	1	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	BOWMN_6_HYDRO	32480	BOWMAN	9.11	1.98	1	Sierra	Drum-Rio Oso, South of Palermo,	Aug NQC	MUNI

								South of Table Mountain		
PG&E	BUCKCK_2_HYDRO				0.45		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	31.03	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	26.97	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				0.90		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	DAVIS_1_SOLAR2				0.95		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	DAVIS_7_MNMETH				1.96		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	0.30	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	18.00	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				0.00		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	31.84	1	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	GRNLF1_1_UNITS	32491	GRNLEAF1	13.8	15.12	2	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	33.87	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				0.87		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	66.49	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	85.41	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	66.49	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	8.40	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	PLACVL_1_RCKCRE				0.00		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	3.20		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				0.92		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	9.79	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	21.81	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
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	23.98	1	Sierra	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	Net Seller

PG&E	YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	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	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	0.19	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.19	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.19	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	COGNAT_1_UNIT	33818	COG.NTNL	12	41.58	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_7_UTICA				0.00		Stockton	Tesla-Bellota, Stanislaus	Not modeled Energy Only	Market
PG&E	LOCKFD_1_BEARCK				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Market
PG&E	LOCKFD_1_KSOLAR				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Market
PG&E	LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Stockton	Lockeford		MUNI
PG&E	PEORIA_1_SOLAR				1.35		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	PHOENX_1_UNIT				2.00		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	82.90	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	82.90	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	133.59	1	Stockton	Tesla-Bellota		Market
PG&E	SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	4.19	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	SPIFBD_1_PL1X2	33917	FBERBORD	115	1.53	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	18.23	1	Stockton	Tesla-Bellota	Aug NQC	Net Seller
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	5.08	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	5.72	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	3.75	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				0.74		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	33687	STKTN WW	60	0.00	1	Stockton	Weber	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	33830	GEN.MILL	9.11	0.00	1	Stockton	Lockeford	No NQC - hist. data	QF/Selfgen
SCE	ACACIA_6_SOLAR	29878	ACACIA_G	0.48	0.00	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_SOLAR1	29703	SP_ANTG1	0.8	16.07	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR2	29703	SP_ANTG1	0.8	32.13	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR3	29704	SP_ANTG2	0.8	16.07	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR4	29704	SP_ANTG2	0.8	16.06	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR5	29704	SP_ANTG2	0.8	4.02	1	BC/Ventura	Big Creek	Aug NQC	Market

SCE	BIGSKY_2_SOLAR6	29704	SP_ANTG2	0.8	68.29	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR7	29704	SP_ANTG2	0.8	40.17	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	CEDUCR_2_SOLAR1	25054	WDT394_a	0.48	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR2	25052	WDT390_a	0.48	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR3	25058	WDT603L	0.48	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR4	25056	WDT439L	0.48	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				4.37		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	DELSUR_6_SOLAR1				5.39		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	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		Market
SCE	GOLETA_6_EXGEN	24362	EXGEN2	13.8	2.17	G1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	GOLETA_6_EXGEN	24326	EXGEN1	13.8	1.49	S1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	GOLETA_6_GAVOTA	24057	GOLETA	66	0.51		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	GOLETA_6_TAJIGS	24057	GOLETA	66	2.93		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				4.12		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LITLRK_6_SOLAR2				1.61		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LITLRK_6_SOLAR4				2.41		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	MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	BC/Ventura	Ventura, S.Clara, Moorpark		Market
SCE	MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	BC/Ventura	Ventura, S.Clara, Moorpark		Market
SCE	MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	BC/Ventura	Ventura, S.Clara, Moorpark		Market
SCE	MOORPK_2_CALABS	25081	WDT251	13.8	4.90	EQ	BC/Ventura	Ventura, Moorpark	Aug NQC	Market
SCE	MOORPK_6_QF	29952	CAMGEN	13.8	26.07	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	51.71	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				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	OASIS_6_SOLAR2	25075	SOLARISG	0.2	16.07	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	OMAR_2_UNIT 1	24102	OMAR 1G	13.8	74.30	1	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 2	24103	OMAR 2G	13.8	75.90	2	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 3	24104	OMAR 3G	13.8	78.40	3	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	BC/Ventura	Big Creek		Net Seller
SCE	ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	BC/Ventura	Ventura, Moorpark		Market
SCE	ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	BC/Ventura	Ventura, Moorpark		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	29918	VLYFLR_G	0.2	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	PLAINV_6_DSOLAR	29914	DRYRCH G	0.8	8.03	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	PLAINV_6_NLRSR1				16.07		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	PLAINV_6_SOLAR3	25089	TOT524_PV	0.42	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	PLAINV_6_SOLARC	25086	TOT521_a	0.2	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	PMDLET_6_SOLAR1				8.20		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	RECTOR_2_KAWEAH	24212	RECTOR	66	0.01		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	RECTOR_2_KAWH 1	24212	RECTOR	66	0.13		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	RECTOR_2_QF	24212	RECTOR	66	0.00		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	RSMSLR_6_SOLAR1	29984	DAWNGEN	0.8	20.00	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	RSMSLR_6_SOLAR2	29888	TWILGHTG	0.8	17.54	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	19.30	D1	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	SAUGUS_6_QF	24135	SAUGUS	66	0.63		BC/Ventura	Big Creek	Not modeled Aug NQC	QF/Selfgen
SCE	SAUGUS_7_CHIQCN	24135	SAUGUS	66	4.71		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				0.45		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	SNCLRA_2_UNIT1				16.31		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	SNCLRA_6_OXGEN	24110	OXGEN	13.8	33.50	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.52	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	SNCLRA_6_WILLMT	24159	WILLAMET	13.8	13.61	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
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	6.40		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	SPRGVL_2_TULESC	24215	SPRINGVL	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	2	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	3	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	4	BC/Ventura	Big Creek	Aug NQC	Market

SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	5	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	66.33	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	67.26	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	18.40	D1	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.40	D2	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	VESTAL_2_KERN	24372	KR 3-1	11	0.20	1	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_KERN	24373	KR 3-2	11	0.19	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	25069	WDT43331	0.36	13.85	EQ	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_SOLAR2	25071	WDT43333	0.36	3.00	EQ	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_SOLAR2	25070	WDT43332	0.36	6.69	EQ	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_UNIT1				2.93		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	0.26	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_APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	BC/Ventura	Big Creek	No NQC - hist. data	Market
SCE	ZZ_APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	BC/Ventura	Big Creek	No NQC - hist. data	Market

SCE	ZZ_APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	BC/Ventura	Big Creek	No NQC - hist. data	Market
SCE	ZZ_NA	24340	CHARMIN	13.8	0.00	1	BC/Ventura	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
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	ZZZ_New Unit	97676	WDT1200AG1	0.48	0.00	1	BC/Ventura	Ventura, S.Clara, Moorpark	Energy Only	Market
SCE	ZZZ_New Unit	25076	WDT1098	0.4	50.00	EQ	BC/Ventura	Big Creek	No NQC - Pmax	Market
SCE	ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	LA Basin	Western		Market
SCE	ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	LA Basin	Western		Market
SCE	ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	LA Basin	Western		Market
SCE	ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	LA Basin	Western		Market
SCE	ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	LA Basin	Western		Market
SCE	ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	LA Basin	Western		Market
SCE	ALTWD_1_QF	25635	ALTWIND	115	4.15	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ALTWD_1_QF	25635	ALTWIND	115	4.14	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	52.84	1	LA Basin	Western	Aug NQC	Net Seller

SCE	ARCOGN_2_UNITS	24012	ARCO 2G	13.8	52.84	2	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24013	ARCO 3G	13.8	52.84	3	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24014	ARCO 4G	13.8	52.84	4	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24163	ARCO 5G	13.8	26.42	5	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24164	ARCO 6G	13.8	26.42	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	3.49	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	0.00		LA Basin	Western	Not modeled	MUNI
SCE	BUCKWD_1_NPALM1	25634	BUCKWIND	115	1.36		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	BUCKWD_1_QF	25634	BUCKWIND	115	2.64	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.16	W5	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CABZON_1_WINDA1	29290	CABAZON	33	8.90	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CAPWD_1_QF	25633	CAPWIND	115	3.45	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	CENTER_2_QF	29953	SIGGEN	13.8	17.40	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	5.90	1	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	5.90	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				5.09		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				0.34		LA Basin	Eastern, Eastern Metro	Not modeled	Market
SCE	CHINO_2_SOLAR2				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.18	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				0.75		LA Basin	Western	Not modeled Aug NQC	Market
SCE	DELAMO_2_SOLAR2				1.11		LA Basin	Western	Not modeled Aug NQC	Market
SCE	DELAMO_2_SOLAR6				0.00		LA Basin		Not modeled Energy Only	
SCE	DELAMO_2_SOLRC1				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	DELAMO_2_SOLRD				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	DEVERS_1_QF	25632	TERAWND	115	8.49	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_QF	25639	SEAWIND	115	10.18	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	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	0.01	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	0.21		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_2_RTS010	24055	ETIWANDA	66	0.86		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS015	24055	ETIWANDA	66	1.03		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS017	24055	ETIWANDA	66	1.41		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS018	24055	ETIWANDA	66	0.58		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS023	24055	ETIWANDA	66	1.43		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS026	24055	ETIWANDA	66	4.82		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS027	24055	ETIWANDA	66	1.57		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_SOLAR5				0.00		LA Basin		Not modeled Energy Only	
SCE	ETIWND_2_UNIT1	24071	INLAND	13.8	19.71	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	0.89	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		Market
SCE	ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	LA Basin	Eastern, Eastern Metro		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	3.20		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.79	G1	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.27	G2	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.62	G3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_WIND	24815	GARNET	115	0.40	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_1_WINDS	24815	GARNET	115	3.48	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	0.45		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Market
SCE	GARNET_2_WIND1	24815	GARNET	115	1.83	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND2	24815	GARNET	115	1.76	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND3	24815	GARNET	115	2.22	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND4	24815	GARNET	115	1.73	QF	LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND5	24815	GARNET	115	0.53	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	14.65	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.65	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	26.93	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	LA Basin	Western		Market
SCE	HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	LA Basin	Western		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	9.77	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				2.30		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_ONTARO				2.25		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS032				0.30		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS033				0.46		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_TEMESC				2.60		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	4.19	1	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.19	2	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.19	3	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MTWIND_1_UNIT 1	29060	MOUNTWND	115	6.49	S1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 2	29060	MOUNTWND	115	2.95	S2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 3	29060	MOUNTWND	115	2.41	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	3.56	C1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.56	C2	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.56	C3	LA Basin	Western	Aug NQC	Market

SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.56	C4	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	6.37	S1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_QF	24211	OLINDA	66	0.06		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	OLINDA_7_LNDFIL	24211	OLINDA	66	0.05		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	5.00		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
SCE	PADUA_6_QF	24111	PADUA	66	0.31		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	0.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	PWEST_1_UNIT	24815	GARNET	115	0.20	PC	LA Basin	Western	Aug NQC	Market
SCE	REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	LA Basin	Western		Market
SCE	REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	LA Basin	Western		Market
SCE	REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	LA Basin	Western		Market
SCE	REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	LA Basin	Western		Market
SCE	RENWD_1_QF	25636	RENWIND	115	1.73	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RENWD_1_QF	25636	RENWIND	115	1.72	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	6.03		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	1.20	D1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	SANTGO_2_LNDFL1				15.88		LA Basin		Not modeled Aug NQC	Market
SCE	SANWD_1_QF	25646	SANWIND	115	1.70	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SANWD_1_QF	25646	SANWIND	115	1.70	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP3	24923	MNTV-ST1	18	225.07	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24926	MNTV-ST2	18	225.07	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_QF	24214	SANBRDNO	66	0.12		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen

SCE	SBERDO_2_REDLND	24214	SANBRDNO	66	0.64		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS005	24214	SANBRDNO	66	1.15		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	0.91		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS013	24214	SANBRDNO	66	0.87		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS016	24214	SANBRDNO	66	0.46		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	0.73		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	SENTNL_2_CTG1	29101	SENTINEL_G1	13.8	92.09	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG2	29102	SENTINEL_G2	13.8	92.40	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG3	29103	SENTINEL_G3	13.8	92.36	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG4	29104	SENTINEL_G4	13.8	91.98	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG5	29105	SENTINEL_G5	13.8	91.83	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG6	29106	SENTINEL_G6	13.8	92.16	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG7	29107	SENTINEL_G7	13.8	91.84	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG8	29108	SENTINEL_G8	13.8	91.56	1	LA Basin	Eastern, Valley-Devers		Market

SCE	TIFFNY_1_DILLON	29021	WINTEC6	115	4.96	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TRNSWD_1_QF	25637	TRANWIND	115	7.42	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	3.70		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_RTS044	24160	VALLEYSC	115	3.37		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	16.65	EQ	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Market
SCE	VALLEY_7_BADLND	24160	VALLEYSC	115	0.44		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	1.66	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND2	25645	VENWIND	115	2.83	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND3	25645	VENWIND	115	3.36	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	0.25		LA Basin	Eastern, Eastern Metro	Energy Only	Market

SCE	VISTA_2_RTS028	24901	VSTA	230	2.29		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	EME WCG1	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG2	29202	EME WCG2	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG3	29203	EME WCG3	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG4	29204	EME WCG4	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG5	29205	EME WCG5	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	45.28	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	WALNUT_7_WCOVCT	24157	WALNUT	66	3.45		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WALNUT_7_WCOVST	24157	WALNUT	66	5.12		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WHTWTR_1_WINDA1	29061	WHITEWTR	33	5.22	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	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				5.16		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	BREGGO_6_SOLAR	22082	BR GEN1	0.21	22.44	1	SD-IV	San Diego	Aug NQC	Market

SDG&E	CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.53	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CCRITA_7_RPPCHF	22124	CHCARITA	138	2.17	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	113.75	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	5.38	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	57.15	G1	SD-IV	None	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	45.74	G2	SD-IV	None	Aug NQC	Market

SDG&E	CRELMN_6_RAMON1				1.74		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	CRELMN_6_RAMON2				4.33		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	7.63	1	SD-IV	San Diego	Aug NQC	Wind
SDG&E	CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	43.70	G1	SD-IV	None	Aug NQC	Market
SDG&E	CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	43.70	G2	SD-IV	None	Aug NQC	Market
SDG&E	DIVSON_6_NSQF	22172	DIVISION	69	43.07	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	ELCAJN_6_EB1BT1				7.50		SD-IV	San Diego, El Cajon	Not modeled.	Market
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	ENCINA_7_EA2	22234	ENCINA 2	14.4	104.00	1	SD-IV	San Diego, Encina		Market

SDG&E	ENCINA_7_EA3	22236	ENCINA 3	14.4	110.00	1	SD-IV	San Diego, Encina		Market
SDG&E	ENCINA_7_EA4	22240	ENCINA 4	22	300.00	1	SD-IV	San Diego, Encina		Market
SDG&E	ENCINA_7_EA5	22244	ENCINA 5	24	330.00	1	SD-IV	San Diego, Encina		Market
SDG&E	ENCINA_7_GT1	22248	ENCINAGT	12.5	14.50	1	SD-IV	San Diego, Encina		Market
SDG&E	ENERSJ_2_WIND				23.33		SD-IV	None	Not modeled Aug NQC	Wind
SDG&E	ESCNDO_6_EB1BT1				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Market
SDG&E	ESCNDO_6_EB2BT2				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Market
SDG&E	ESCNDO_6_EB3BT3				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Market
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	57.32	1	SD-IV	None	Aug NQC	Market
SDG&E	IVSLRP_2_SOLAR1	23441	DW GEN2 G2	0.36	57.32	1	SD-IV	None	Aug NQC	Market
SDG&E	IVSLRP_2_SOLAR1	23442	DW GEN2 G3	0.36	57.32	1	SD-IV	None	Aug NQC	Market
SDG&E	IVWEST_2_SOLAR1	23155	DU GEN1 G1	0.2	65.20	G1	SD-IV	None	Aug NQC	Market
SDG&E	IVWEST_2_SOLAR1	23156	DU GEN1 G2	0.2	55.32	G2	SD-IV	None	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	Market

									ISO BAA RA purpose	
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				2.41		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	3.70	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	NIMTG_6_NIQF	22576	NOISLMTR	69	34.98	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	OCTILO_5_WIND	23314	OCO GEN G1	0.69	8.17	G1	SD-IV	None	Aug NQC	Wind
SDG&E	OCTILO_5_WIND	23318	OCO GEN G2	0.69	8.17	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	2.38	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	2.07	2	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	PTLOMA_6_NTCQF	22660	POINTLMA	69	19.74	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	SAMPSN_6_KELCO1	22704	SAMPSON	12.5	6.39	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.28	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				1.87		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market
SDG&E	VLCNTR_6_VCSLR1				2.17		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market
SDG&E	VLCNTR_6_VCSLR2				4.78		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	Q644G	0.31	16.00	1	SD-IV	None	No NQC - est. data	Market
SDG&E	ZZZ_New Unit	23287	Q429 G1	0.31	80.00	1	SD-IV	None	No NQC - est. data	Market
SDG&E	ZZZ_New Unit	22942	BUE GEN 1 G1	0.69	23.12	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	ZZZZZ_ENCINA_7_EA1	22233	ENCINA 1	14.4	0.00	1	SD-IV	San Diego, Encina	Retired	Market
SDG&E	ZZZZZZ_ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	SD-IV	San Diego, El Cajon	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY3	22374	KEARN2CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY4	22376	KEARN3CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY4	22373	KEARN2AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY5	22374	KEARN2CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY5	22375	KEARN3AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_KEARNY_7_KY6	22376	KEARN3CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	SD-IV	San Diego, Miramar	Retired	Market
SDG&E	ZZZZZZ_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 Metcalf-Evergreen #1 115 kV line.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	20
36856	CCCA100	1	6
36854	Cogen	1	6
36854	Cogen	2	6
36863	DVRaGT1	1	6
36864	DVRbGT2	1	6
36865	DVRaST3	1	6
35860	OLS-AGNE	1	5
36858	Gia100	1	5
36859	Gia200	2	5
35854	LECEFGT1	1	5
35855	LECEFGT2	2	5
35856	LECEFGT3	3	5
35857	LECEFGT4	4	5

Table – Herndon

Effectiveness factors to the Herndon-Barton 115 kV line.

Gen Bus	Gen Name	Gen ID	Eff Factor %
34624	BALCH 1	1	18.198
34616	KINGSRIV	1	16.901
34671	KRCDPCT1	1	16.258
34672	KRCDPCT2	1	16.258
34648	DINUBA E	1	15.628
34603	JGBSWLT	ST	12.418
34677	Q558	1	12.418
34690	CORCORAN_3	FW	12.418
34692	CORCORAN_4	FW	12.418
34696	CORCORANPV_S	1	12.418
34699	Q529	1	12.418
34610	HAAS	1	11.344
34610	HAAS	2	11.344
34612	BLCH 2-2	1	11.344
34614	BLCH 2-3	1	11.344
34308	KERCKHOF	1	8.609
34343	KERCK1-2	2	8.609
34344	KERCK1-1	1	8.609
34345	KERCK1-3	3	8.609
34431	GWF_HEP1	1	7.258
34433	GWF_HEP2	1	7.258
34617	Q581	1	4.142
34649	Q965	1	4.142
34680	KANSAS	1	4.142

Table – Western LA Basin

Effectiveness factors to the Serrano – Villa Park #1 or #2 230 kV lines:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
29309	BARPKGEN	1	24
25208	DowlingCTG	1	23
25211	CanyonGT 1	1	23
25212	CanyonGT 2	2	23
25213	CanyonGT 3	3	23
25214	CanyonGT 4	4	23
24066	HUNT1 G	1	20
24067	HUNT2 G	2	20
24325	ORCOGEN	1	20
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24001	ALAMT1 G	1	17
24002	ALAMT2 G	2	17
24003	ALAMT3 G	3	17
24004	ALAMT4 G	4	17
24162	ALAMT7 G	R7	17
24133	SANTIAGO	1	13
24341	COYGEN	1	13
24018	BRIGEN	1	13
24011	ARCO 1G	1	11
24012	ARCO 2G	2	11
24013	ARCO 3G	3	11
24014	ARCO 4G	4	11
24020	CARBGEN1	1	11
24064	HINSON	1	11
24080	LBEACH8G	R8	11
24081	LBEACH9G	R9	11
24139	SERRFGEN	D1	11
24163	ARCO 5G	5	11
24164	ARCO 6G	6	11
24170	LBEACH12	2	11
24170	LBEACH12	1	11
24171	LBEACH34	3	11
24171	LBEACH34	4	11
24327	THUMSGEN	1	11
24328	CARBGEN2	1	11
24062	HARBOR G[38]	1	11

[38] Harbor generating units are currently on mothballed status.

24062	HARBOR G	HP	11
25510	HARBORG4	LP	11
24079	LBEACH7G	R7	11
24173	LBEACH5G	R5	11
24174	LBEACH6G	R6	11
24070	ICEGEN	D1	11
29308	CTRPKGEN	1	10
29953	SIGGEN	D1	10
24022	CHEVGEN1	1	9
24023	CHEVGEN2	2	9
24047	ELSEG3 G	3	9
24048	ELSEG4 G	4	9
24094	MOBGEN1	1	9
24329	MOBGEN2	1	9
24330	OUTFALL1	1	9
24331	OUTFALL2	1	9
24332	PALOGEN	D1	9
24333	REDON1 G	R1	9
24334	REDON2 G	R2	9
24335	REDON3 G	R3	9
24336	REDON4 G	R4	9
24337	VENICE	1	9
29009	CHEVGEN5	1	9
29009	CHEVGEN5	2	9
29901	ELSEG5GT	5	9
29902	ELSEG6ST	6	9
29903	ELSEG7GT	7	9
29904	ELSEG8ST	8	9
24121	REDON5 G	5	9
24122	REDON6 G	6	9
24123	REDON7 G	7	9
24124	REDON8 G	8	9
24239	MALBRG1G	C1	8
24240	MALBRG2G	C2	8
24241	MALBRG3G	S3	8
24342	FEDGEN	1	8
29951	REFUSE	D1	8
29005	PASADNA1	1	5
29006	PASADNA2	1	5
29007	BRODWYSC	1	5

Table – LA Basin

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

Appendix B - Effectiveness factors for procurement guidance

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.