BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations	Rulemaking 19-11-009 (Filed November 7, 2019)

INITIAL TRACK 3.B PROPOSAL AND COMMENTS ON ADDITIONAL PROCESS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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I. Introduction

The California Independent System Operator Corporation (CAISO) hereby provides its proposals for Track 3.B per the July 7, 2020 *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling* (Amended Scoping Memo).

II. Discussion

The Amended Scoping Memo specifically notes that Track 3.B of this proceeding will include an

> examination of the broader [resource adequacy] structure to address energy attributes and hourly capacity requirements, given the increasing penetration of use-limited resources, greater reliance on preferred resources, rolling off of a significant amount of long-term tolling contracts held by utilities, and material increases in energy and capacity prices experienced in California over the past years.[1]

The CAISO agrees with the scope of this proposed examination and submits that the Commission should consider several major structural changes to the resource adequacy program. The CAISO submits four independent resource adequacy program proposals for the Commission's consideration, each of which are designed to address system energy and capacity needs based on the evolving resource adequacy fleet. The CAISO also submits an informational update regarding its revised flexible capacity product and its prior proposal advocating for multi-year system and flexible requirements.

Table 1, below, provides a summary of the CAISO's proposals along with relevant information regarding CAISO stakeholder processes, targeted implementation timelines, and

[1] Amended Scoping Memo, p. 4-5.

supporting attachments. The CAISO notes that several of these proposals are still being developed in the ongoing CAISO Resource Adequacy Enhancements stakeholder initiative. The CAISO recently issued a Fifth Revised Straw Proposal in that initiative and is scheduled to issue a Draft Final Proposal in October. The CAISO looks forward to working with the Commission and other stakeholders to further develop these proposals. Lastly, the CAISO is still in the process of developing important market rule changes that will lead to both a revised flexible capacity product and multi-year system and flexible capacity requirements. The CAISO respectfully requests the Commission allow additional time to discuss both in Track 4 of this proceeding or another track that would allow for the adoption of a multi-year system and flexible capacity requirements for the 2023 resource adequacy year.

TABLE 1: SUMMARY OF CAISO PROPOSALS AND INFORMATIONAL UPDATE

Issue	Initial proposal?	Related CAISO processes	Targeted resource adequacy year	Attachment reference
Effective load carrying capability for variable output demand response resources	Yes	None	2022	A – E3 ELCC Study
Availability-limited resource Procurement	Yes	Local Capacity Technical (LCT) Studies	2021 & 2022 bridge; 2023 binding	B – 2018 CAISO Testimony C – LCT Studies
Unforced capacity (UCAP)	Yes	Resource Adequacy Enhancements stakeholder initiative	2022 bridge; 2023 binding	D – Resource Adequacy Enhancements Fifth Straw Proposal
Resource adequacy imports	Yes	Resource Adequacy Enhancements stakeholder initiative	2022 bridge; 2023 binding	D – Resource Adequacy Enhancements Fifth Straw Proposal
Multi-year system and flexible capacity	Informational update	Resource Adequacy Enhancements stakeholder initiative	2023 binding	n/a

A. CAISO Proposal 1: Effective Load Carrying Capability Methodology for Variable-Output Demand Response

The Commission should use an effective load carrying capability (ELCC) methodology to calculate qualifying capacity for variable-output demand response resources. The Commission should work to implement this new ELCC methodology for the 2022 resource adequacy year.

1. Background

Variable-output demand response resources are demand response resources whose maximum output can vary over the course of a day, month, or season. This variable-output could be due to production schedules, duty cycles, availability, seasonality, temperature, occupancy, etc. Variable-output demand response resources have unique characteristics that can limit their use. First, they have strict use-limitations such as availability during limited hours, days, or seasons. Second, they often have limited energy and carbon offsetting capabilities because they are only available to displace energy production during a very limited number of hours per year. Lastly, their variable output nature means their load reduction capability varies by time of day, occupancy, weather, and production. As a result, their load reduction capability is more akin to that of variable energy resources (which the Commission evaluates using an ELCC methodology) rather than a conventional, fuel-backed resource.

The Commission's current counting methodology for demand response—the load impact protocol (LIP)—does not consider use-limitations, limited energy and carbon offsetting capabilities, or the variable nature of most demand response. The LIP is an anachronism that was useful when the resource adequacy program's primary concern was to meet peak capacity needs. At that time, energy sufficiency was a non-issue because the large amount of gas, nuclear, and hydro resources could support system energy needs. However, circumstances have changed dramatically. The CAISO is concerned continued use of the LIP for the vast majority of demand response overvalues these resources' reliability contribution. This concern has increased with the Commission's recent adoption of a demand response category under the maximum cumulative capacity (MCC) bucket construct that allows LSEs to procure demand response resources for up to 8.3 percent of their total system resource adequacy requirement. The Commission's decision adopting this figure acknowledges this limit reflects demand response "growth of approximately 100 percent over the current levels when accounting for the 15 percent [planning reserve margin] adder."[2] Similar to when the Commission adopted an ELCC methodology to replace its prior exceedance methodology for wind and solar resources, the current framework for variable-output demand response should be overhauled to ensure these resources are appropriately relied on to meet reliability needs and subsequently not overvalued as resource adequacy.

2. Proposal

The Commission should calculate the qualifying capacity of variable-output demand response resources based on an ELCC methodology. Unlike the LIP, an ELCC methodology more accurately captures the value of demand response by accounting for its use- and energy-limitations and variable-output nature. Additionally, an ELCC methodology assesses how the capacity value of supply-side demand response, as a peak reduction resource, declines and saturates as other energy-limited resources—like battery storage—compete with demand response to serve the same peak capacity hours. The Commission must consider this critical information as it vets future resource needs and its efforts to achieve SB 100 goals through its Integrated Resource Planning (IRP) proceeding.

The CAISO engaged Energy+Environmental Economics (E3) to develop an ELCC methodology for demand response to provide the Commission and parties a concrete example of how to calculate ELCC values for demand response resources. The CAISO provides a link to the E3 ELCC study in Attachment A (E3 ELCC Study).[3] This study used actual 2019 bid data provided by Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (SCE) to calculate the ELCC values for individual demand response programs.[4] The CAISO recommends the Commission use bid data to develop ELCC values because bids should reflect the true availability of the resource considering both program parameters—such as hours of availability per day—and variability caused by weather sensitivity or other factors. The CAISO notes that bid data is likely the most robust information available to evaluate demand response

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[2] Decision 20-06-031, *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program*, June 30, 2020, p. 57.

[3] In the ESDER 4 initiative, the CAISO also explored modifications to variable output demand response bidding that reflects variable output to align with the ELCC methodology. http://www.caiso.com/StakeholderProcesses/Energy-storage-and-distributed-energy-resources.

[4] As a result of the ELCC study, SCE identified and made modifications to their bids to increase the MW amount offered. Because these modifications were identified after the conclusion of the study, these modifications are not represented in the study in Attachment A.

availability, but the Commission should still require regular testing for demand response resources to ensure bids accurately reflect resource capabilities.

E3's model evaluated demand response as a resource of "last resort" on both a "first in" and "last in" basis. A "first in" ELCC measures marginal ELCC as if the resource were the only intermittent or energy-limited resource on the system, ignoring interactive effects of other resources. A "last in" ELCC measures the marginal ELCC after all other intermittent or energy-limited resources have been added to the system, capturing all interactive effects with other resources. Assumptions on bidding and dispatch should be vetted with parties and considered holistically with other ELCC refinements considered in Track 3.B.

The E3 ELCC Study found the LIP overvalues capacity contributions of demand response by 40 percent or more.[5] An ELCC study more accurately reflects demand response resource reliability contributions for two main reasons: (1) demand response in aggregate does not bid into the CAISO market at levels equal to its net qualifying capacity value given its variability and use-limitations, and (2) demand response is bid at times that are either not optimal or not for long enough durations to earn full ELCC value.

Another major finding from the E3 ELCC Study is that it is possible to develop an ELCC methodology that can evaluate different classes of demand response resources with different use and availability limitations. E3's ELCC methodology achieved this result by allocating the overall demand response resource category ELCC to individual programs based on expected output during peak, maximum number of calls per year, and maximum duration per call. This addresses the purported concern that demand response programs are too heterogeneous to apply an ELCC methodology. Similarly, this addresses the Commission's Track 2 Decision request to specifically address bidding and dispatch assumptions.[6] The E3 ELCC Study found the determining factors are when, where, how much, and how fast the end-uses collectively respond and deliver load curtailment to the system. In other words, it is the demand program design that matters, not the specific and heterogeneous underlying end-uses that make up a demand response resource. In fact, demand response program designs are generally more similar than dissimilar

[5] Attachment A, E3 ELCC Study, p.14:

[6] Track 2 decision requested: "Future proposals to develop ELCC values for DR and storage should include specific proposals regarding the bidding and dispatch that should be assumed for different DR programs and energy storage facilities operating in the market and how these should be modeled in ELCC studies."

when it comes to their use, availability, and response time, all of which are the factors that drive demand response's capacity value.

The Commission should lead the discussion and build a record assessing demand response's capacity value based on its reliability contributions and the clean energy needs of the transforming grid. This matter is appropriately considered in the resource adequacy proceeding because it would modify how the Commission establishes qualifying capacity values for the resource adequacy program, rather than merely refining the existing LIP methodology. In building a record, the Commission should leverage the CAISO's work and investment in this effort to consider how Energy Division staff can evaluate supply-side demand response under an ELCC methodology, as it does for wind, solar, and storage. The E3 ELCC Study demonstrates it is possible and appropriate to use an ELCC methodology to assess the value of demand response.

The Commission should commit to developing, and vetting an ELCC methodology for demand response in Track 3.B. Ultimately, the Commission should seek to facilitate transition of the qualifying capacity counting from the current LIP to an ELCC methodology by the end of Track 4, with the new ELCC methodology applying for the 2022 resource adequacy program year.

B. Proposal 2: Availability Limited Resource Procurement

The Commission should ensure those responsible for procuring resource capacity in local capacity areas, including the central procurement entities and entities procuring capacity in the San Diego Gas and Electric Company (SDG&E) transmission access charge footprint, procure sufficient resource adequacy resources to account for availability-limited resource characteristics in the local capacity areas and sub-areas starting in the 2023 resource adequacy year.

1. Background

Availability-limited resources are resources that have significant dispatch limitations such as limited duration hours (*e.g.*, per year, season, month, or day) or event calls (*e.g.*, per year, season, month or consecutive days) that would limit the resources' ability to respond to a contingency event within a local capacity area. This definition is limited to resources that count towards meeting a local capacity area or sub-area need. In 2018 testimony supporting this definition, the CAISO described the proposed hourly load and resource analysis it would develop to inform the Commission's resource adequacy proceeding and corresponding load serving entity

(LSE) or central buyer procurement efforts.[7] The CAISO has included this testimony (2018 CAISO Testimony) in Attachment B.

In Decision (D.) 19-06-026 the Commission adopted the definition and agreed that "it is important to consider availability limited resources, particularly when constructing new resources" and recognized the need "to work closely with the CAISO to ensure that availability needs are met in all local reliability areas."[8] The CAISO's current proposal provides new local capacity area details that will enable the Commission to direct procurement efforts to ensure local reliability needs are met.

2. Proposal

Since the Commission issued D.19-06-026, the CAISO has completed the first phase of the hourly load and resource analysis and submitted it into Track 2 of this proceeding as part of the 2021 Local Capacity Technical (LCT) Study (Attachment C).[9] Additionally, the CAISO has conducted a 2025 LCT Study with the same methodology (Attachment C). For this first phase in the hourly load and resource analysis, the CAISO focused on battery storage due to significant procurement interest and activity.[10] In later phases, the CAISO may study other availability limited resources such as demand response.

The CAISO presented the methodology and results in the CAISO's annual local capacity requirements stakeholder process. No stakeholders expressed concern with, or opposed the CAISO's methodology or results.[11]

The CAISO's analysis estimated the characteristics (MW, MWh, discharge duration) required from battery storage technology to seamlessly integrate in each local area and sub-area.[12] Moreover, the CAISO expects that for batteries that displace other local resource

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[7] *See* Attachment B, 2018 CAISO Testimony, p. 3.
[8] Decision (D.) 19-06-026, *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program*, July 5, 2019, p. 53.
[9] *See,* Attachment C, 2021 Local Capacity Technical (LCT) Study
[10] For example, the CAISO queue registered 69,193 MW of energy storage projects in June 2020. *See* slide 3: http://www.caiso.com/Documents/Briefing-Renewables-EnergyStorage-Generator-Interconnection-Queue-Presentation-July2020.pdf
[11] *See*: http://www.caiso.com/Documents/ISOResponsestoComments_2021and2025FinalLocalCapacityRequirementsTechnicalStudyResults.pdf
[12] For more details on methodology and analysis results, *see* Attachment C, Section 2.4: Estimate of Battery Storage Needs due to Charging Constraints in both the 2021 and 2025 Local Capacity Technical Studies.

adequacy resources the transmission capability under the most limiting contingency, and the other local capacity resources, must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period.

The following example illustrates how to interpret the battery storage analysis. The example utilizes the following peak day forecast profile of the Placer sub-area, which is reproduced from the 2021 LCT Study.[13]

Figure 1: Placer LCR Sub-area 2021 Peak Day Forecast Profiles

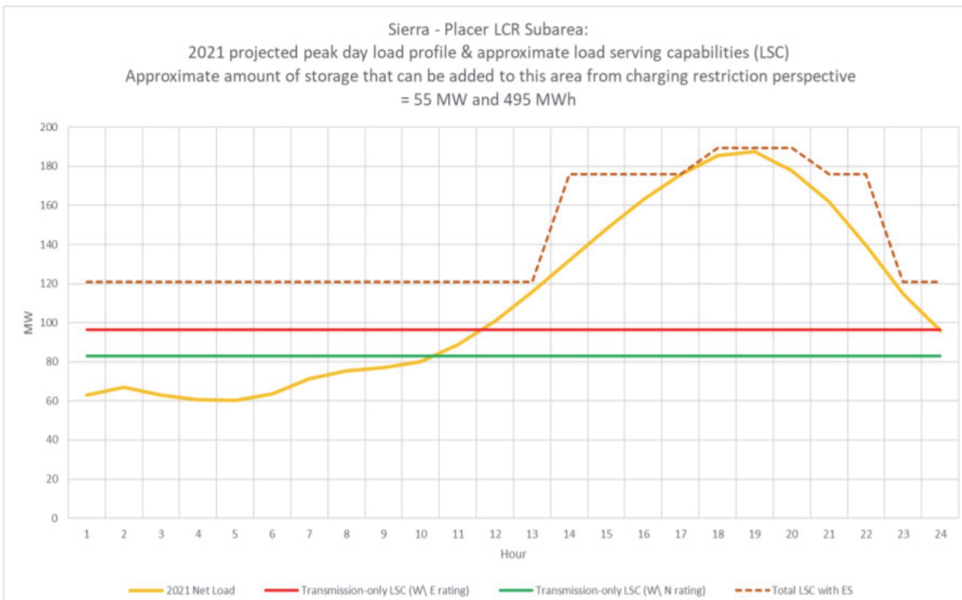

Figure 1 illustrates the load serving capabilities (LSC) of the Placer sub-area under three different instances as compared to the 2021 net load. The brown dotted line reflects the total LSC with ES (energy storage) reflecting the maximum level of battery storage penetration in this sub-area that would still allow for recharging the battery under contingency conditions from the capability of the grid plus the rest of the resources required to meet the local capacity requirement need in this sub-area. The LSC with ES line provides the three dimensions CAISO used to evaluate battery storage characteristics: MW, MWh, and discharge duration. The approximate difference between the highest (175 MW)[14] and lowest (120 MW) points of the line is 55 MW and represents the maximum capacity of battery storage the Placer sub-area can accommodate. The approximate area under this line bounded by the lowest point of the line

[13] *See,* Attachment C, Figure 3.3-15 Placer LCR Sub-area 2021 Peak Day Forecast Profiles, 2021 LCT, p. 46.
[14] The height differences are approximate as is the energy under the Total LSC with ES line.

(120 MW) is 495 MWh, which is the energy requirement the battery needs to serve and is a characteristic not captured by today's resource adequacy program. Similarly, the maximum discharge duration is 10 hours and is measured as the widest gap in the curve between the thirteenth and twenty-third hour. Again, duration is not an attribute that is sufficiently considered in the resource adequacy program. The CAISO has provided the same analysis for each non-flow-through local capacity and sub-area in both the 2021 and 2025 LCT Studies.

Under this example, and assuming no batteries are procured and all conditions remain the same in the Placer sub-area between now and 2023, the central procurement entity should ensure that if 55 MW of batteries are procured, they should also deliver the 495 MWh of energy with a maximum needed duration of 10 hours. Furthermore, if more than 55 MW of batteries are procured, only this amount would be eligible to offset retiring resources because of the charging limitations in this local area. Each LCT Study also provides a summary table noting what resource types incremental battery storage resources are replacing. In the 2021 LCT Study, the 55 MW (495 MWh) of incremental battery procurement in the Placer sub-area will only offset other required local area resources, which are mostly hydro resources.[15]

Installing battery storage with insufficient characteristics (MW, MWh and duration) will not result in a one-for-one reduction of the local area or sub-area need for other types of resources. The CAISO expects the overall resource adequacy portfolio provided by all LSEs to account for incremental capacity beyond the minimum LCR need, in MWs required from other types of resources for all areas and sub-areas where LSEs have procured battery storage beyond the charging capability or with incorrect characteristics (MW, MWh and duration). If sufficient incremental capacity is not provided, the CAISO may need to use the expanded local capacity procurement back stop authority currently contemplated in the CAISO's Resource Adequacy Enhancements stakeholder initiative to assure reliability standards are met throughout the day, including off-peak hours.

The CAISO proposes that starting in 2023, the central procurement entities and the entities in the San Diego Gas and Electric transmission access charge footprint (collectively the responsible local capacity procurement entities) procure sufficient resource adequacy resources

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[15] *See* Attachment C, Table 3.1-3 2021 Battery Storage Characteristics Limited by Charging Capability, 2021 LCT Study, p. 27.

to accommodate availability limited resources. LSEs should use the CAISO's analysis in the 2021 and 2025 LCT Studies immediately to inform battery storage procurement and recognize that each sub-area and local area has different requirements that may already exceed and not be satisfied by the resource adequacy program's minimum four hour duration requirement. These studies can also inform the type of and level of retirement possible with additional battery storage procurement. Although it will be difficult for individual LSEs to coordinate on procurement in multi-LSE sub-areas and local areas, the CAISO believes the responsible local capacity entities will be in a better position to use the analyses to coordinate procurement across LSEs starting in 2023. This timing coincides with the CAISO's expected implementation of backstop authority discussed in the CAISO's Resource Adequacy Enhancements stakeholder initiative.[16]

C. Proposal 3: Unforced Capacity (UCAP)

In the Resource Adequacy Enhancements stakeholder initiative, the CAISO is developing a proposal to assess capacity needs and resource contributions using an unforced capacity (UCAP) methodology instead of the existing methodology relying on net qualifying capacity only. The UCAP methodology recognizes unit-specific forced outage rates and this information should be reflected in procurement. The Commission should adopt the UCAP methodology that arises from the Resource Adequacy Enhancements initiative. A system UCAP requirement would replace the current static planning reserve margin (PRM) with a superior metric that assesses system needs considering the reliability of the resource adequacy fleet. The transition to the UCAP methodology requires two foundational changes to the current resource adequacy program. The first is a shift in how resources are counted towards meeting resource adequacy obligations. The second is establishing upfront capacity procurement targets that align with the CAISO's operational needs, account for ancillary services requirements, and recognize forced and planned outage impacts. The CAISO discusses both of these elements in detail below, including how UCAP would be applied to local capacity requirements.

1. Background

The rapid transformation to a more variable and energy limited resource fleet and the

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[16] *See* Attachment D, RA Enhancements Fifth Revised Straw Proposal.

migration of load to smaller and more diverse LSEs requires re-examining all aspects of the resource adequacy program. In 2006, at the onset of the resource adequacy program in California, natural gas, nuclear, and hydroelectric resources were the predominant generation technology types. Although some of these resources were subject to use-limitations due to environmental regulations, start limits, or air permits, they were generally available to produce energy when needed given they all had fairly dependable fuel sources. However, as the fleet transitions to achieve the objectives of SB 100,[17] the CAISO must rely on a much different resource portfolio to reliably operate the grid. In the Resource Adequacy Enhancements stakeholder initiative, the CAISO, in collaboration with Commission Energy Division staff and stakeholders, is exploring reforms to the CAISO's resource adequacy rules, requirements, and processes to ensure continued reliability and operability under transforming grid conditions.

A vastly more robust framework is needed to ensure future reliability as system conditions change rapidly, resources retire, and there is increased competition for limited capacity in the west. Accordingly, the CAISO is developing a proposal through its stakeholder process to move to a UCAP paradigm that would: (1) account for unit-specific forced outage rates up-front and ahead of showings (rather than through capacity substitution provisions and after-the fact charges); (2) help LSEs identify which resources contribute the most to reliability; and (3) incentivize resource owners to invest in proper maintenance to increase their resources' availability and, therefore, the amount of resource adequacy capacity they can sell.[18]

2. Proposal

The CAISO's proposal has two primary elements. First, the CAISO's proposal incorporates a UCAP counting methodology to determine capacity values for generation resources. This UCAP counting methodology moves away from relying only on a resource's net qualifying capacity. This change is necessary because the current planning reserve margin assumed forced outage rates are inaccurate (*i.e.*, unreasonably low) and the tools the CAISO currently uses to incentivize replacement capacity for forced outages are ineffective and fail to adequately incentivize resources to provide replacement capacity. The Commission should

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[17] The objective of SB 100 is "that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045." https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[18] Moving to an UCAP paradigm will also mean eliminating RAAIM.

adopt a resource adequacy counting methodology that better incentivizes LSEs to procure more reliable resources in the first instance and resources to avoid forced outages. The CAISO's UCAP approach provides those incentives.

The second element of the CAISO's proposal establishes UCAP-based procurement requirements. Setting requirements in terms of UCAP is the best approach to ensure that the CAISO can reliably meet system needs. The CAISO provides preliminary details regarding the efforts to help determine the UCAP quantity needed to reliably operate the grid, but notes that these efforts are still in progress. Over the course of this proceeding and the CAISO's Resource Adequacy Enhancements Stakeholder initiative, the Commission and CAISO must work collaboratively to determine the correct UCAP system requirement levels and how the Commission's resource adequacy requirements support the CAISO's reliability requirements, including developing an additional planned outage reserve margin to facilitate short-term, intra month outages for resource adequacy resources.

a. Transitioning Resource Counting Rules

Since the Commission established the PRM effective in 2006, the PRM included an assumed system-wide forced outage rate at four to six percent of the total 15 percent PRM.[19] However, the CAISO has observed forced outage rates far exceeding this amount. Table 2 provides the average daily forced outage rates for resource adequacy resources from May 2018 through April 2020. In nearly all months, the resource adequacy fleet exceeded the static four to six percent forced outage rate assumed in the PRM. On average, the CAISO resource adequacy resources experienced a daily forced outage rate of 9.38 percent.

[19] D.04-01-050 adopts a 15-17 percent reserve level, which includes an operating reserve margin of seven percent. Given a forecasting margin of error of four percent, the estimated system forced outage rate is four to six percent. D.04-10-035 accelerates the full implementation of the 15-17 percent PRM from 2008 to 2006.

Table 2: Average monthly forced outage rates for all resource adequacy resources, May 2018 through April 2020

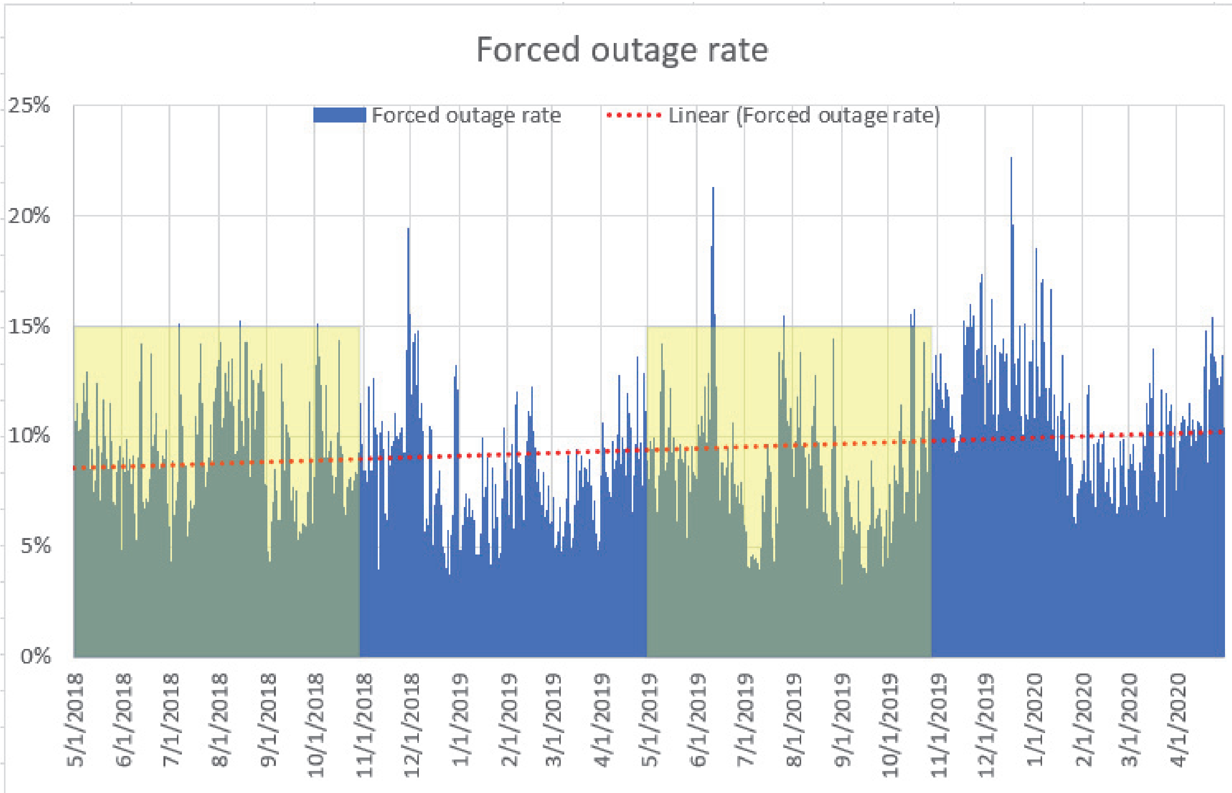
Month	2018	2019	2020	Mean
1		6.53	11.02	8.78
2		8.52	8.66	8.59
3		6.82	9.57	8.20
4		9.52	11.42	10.47
5	9.53	9.07		9.30
6	8.79	10.15		9.47
7	9.43	7.66		8.55
8	11.66	8.78		10.22
9	7.65	6.11		6.88
10	9.61	10.11		9.86
11	9.97	12.8		11.39
12	8.57	13.24		10.91
Average	9.40	9.11	10.17	**9.38**

Source: CAISO Customer Interface for Resource Adequacy (CIRA) data

Figure 2 below shows resource adequacy unit forced outage rates from May 1, 2018 through April 30, 2020. This figure shows forced outage rates regularly exceeded ten percent and exceeded 15 percent on multiple occasions, including on higher load days and during peak-load seasons. Further, the data shows that the resource adequacy resource forced outage rate increased over time as shown by the red dotted line in Figure 2, which reflects prevailing direction of the forced outages rates.[20]

[20] The trend line in Figure 2 was produced using the Excel functionality in which the data presented in Figure 2 was evaluated.

Figure 2: Daily forced outage rates, May 1, 2018 through April 30, 2020



Currently the CAISO relies on substitution rules and the resource adequacy availability incentive mechanism (RAAIM) to discipline capacity availability. However, the CAISO has found that these rules (1) may not ensure substitute capacity is provided in a timely manner, (2) provide perverse incentives force risk mitigation, (3) allow for cross-subsidization of outages within a Scheduling Coordinators (SCs) portfolio of resources, and (4) do not provide an up-front incentive to reliably maintain resources. The need to find substitute capacity for forced outages, by definition, happens with very little notice. Often, it is either not possible for the SC to find substitute or the capacity costs more than the SC is willing to pay.[21] To mitigate the risk of not being able to find substitute capacity, an SC may withhold capacity from the bilateral market to self-provide substitute capacity. This withholding decreases the amount of capacity available for both month-ahead resource adequacy sales and substitute capacity.

Additionally, most SCs have a portfolio of resources. This allows them to recoup RAAIM charges assessed against one resource through incentive payments paid to another

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[21] The latter is particularly true if the resource is above the 94.5 percent availability.

resource. This cross-subsidization further reduces the incentive to procure replacement capacity, potentially leaving the CAISO with insufficient capacity. This increases backstop capacity risk and can degrade system reliability. The CAISO assessed 2018 and 2019 RAAIM charges and found that many SCs did recover all or most of their non-availability charges through incentive payments to other resources. Further, RAAIM only offers an after-the-fact penalty and does not actually incentivize or assure sufficient resource availability,[22] allowing resources to defer maintenance until the outage occurs. These represent some of the flaws the CAISO has identified with the existing RAAIM structure.[23]

Under the CAISO's proposed UCAP paradigm, the Commission would continue to determine qualifying capacity values, including ELCC values, for resources. The CAISO would continue to establish net qualifying capacity values using its deliverability assessment as it does today.[24] To account for outages, the CAISO will establish resource specific UCAP values by discounting the net qualifying capacity by individual unit's forced outage rates. The CAISO and the Commission would use the resulting UCAP system, local, and flexible resource adequacy showings and assessments. For resources with qualifying capacity calculated using an ELCC methodology, the CAISO would use the ELCC value, with any reductions for deliverability, as the UCAP value. This is because the ELCC methodology already accounts for forced outages. Specific details regarding how the CAISO will calculate UCAP values for various resource types are provided in Section 4.1.2. of the CAISO's Fifth Revised Straw Proposal in the Resource Adequacy Enhancements stakeholder initiative (Attachment D). As indicated above, the CAISO will continue to vet these matters further with the Commission and stakeholders.

b. Establishing System UCAP Requirements

The CAISO is conducting an assessment of actual June and July 2020 resource adequacy showings using deterministic and stochastic production simulation. This production simulation was originally designed to demonstrate the capabilities needed to conduct a resource adequacy portfolio assessment (see Section 4.1.3. of Attachment D for more information regarding this assessment). However, the CAISO believes this study will also provide additional context regarding how to establish system UCAP requirements. The CAISO will issue a supplemental

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[22] *See* Attachment D, RA Enhancements Fifth Revised Straw Proposal, Figures 21 and 22, pp. 99-100.
[23] For additional details regarding challenges with RAAIM, *see* Attachment D, Section 8.3.
[24] The CAISO would continue to use net qualifying capacity to establish maximum allowable UCAP values.

report detailing the inputs, assumptions, and results of these assessments to inform the Resource Adequacy Enhancements initiative. This supplement will include the results of the assessment in terms of probabilities of stage emergencies and unserved energy. Based on this assessment, the CAISO will make additional recommendations regarding how best to set UCAP requirements. Once this report is issued, the CAISO will work collaboratively with the Commission and stakeholders to determine the proper levels for UCAP requirements.

The CAISO is also exploring options to eliminate planned outage substitution rules. The CAISO proposes to establish two new elements of the resource adequacy program regarding planned outages. First, the CAISO would no longer allow any type of planned outage other than short-term and off-peak opportunity outages between June 1 and October 31 for resource adequacy resources. The CAISO notes that off-peak months provide the greatest opportunity to procure low cost capacity and still ensure adequate capacity is available to the CAISO.

Second, the CAISO proposes developing a planned outage reserve margin for non-summer months. Under this proposal, the UCAP capacity requirement would increase during the non-summer months, creating a well-defined planned outage reserve margin. To be clear, the higher UCAP requirement in the non-summer months does not mean the CAISO's overall capacity needs are higher in these months. Rather, the increased UCAP requirement would reflect that all maintenance outages on resource adequacy capacity must occur during this time, meaning the planned outage rate on the resource adequacy fleet during this time will be substantially higher than during the peak summer months.

The CAISO is not proposing a specific non-peak planned outage reserve margin because it is impossible to declare a fixed number based on historic data. Instead, the size of the planned outage reserve margin should balance LSE costs and reasonable opportunities for resources to undertake necessary maintenance. Over the course of this proceeding and the CAISO's Resource Adequacy Enhancements stakeholder process, the Commission and the CAISO must work to establish a planned outage reserve margin that balances these two factors.

Although this option would require higher overall procurement in non-summer months, it provides several other potential benefits to load. First, it eliminates all planned outage substitution. This removes both the incentive for LSEs to withhold capacity from the market (in order to provide substitute capacity) and the need for resources to include a risk premium in capacity contracts to cover any potential costs of replacement capacity. As a result, the supply of capacity in the bilateral market should increase, and hidden costs included in the contracts should decrease. Instead, all excess capacity should be more readily available for sale in the bilateral capacity market, maximizing LSEs' opportunities to find capacity, when needed, and at a lower price. These benefits can be captured in both peak and off-peak months. Under the existing rules, substitution may be required in all months. Eliminating substitution rules in their entirety should also free up additional capacity during summer months, increasing overall supply available to the CAISO when it is vitally needed and lowering costs.

To simplify resource adequacy accounting, the CAISO also proposes to convert local capacity requirements into UCAP terms. The CAISO's proposal relies on the existing local capacity study methodology, but converts the existing net qualifying capacity requirements into UCAP requirements based on the ratio of net qualifying capacity to UCAP in a given transmission access charge (TAC) area.[25] The Commission could then use the same allocation practices it uses today to allocate those UCAP requirements to its jurisdictional LSEs.

The CAISO intends to bring a final UCAP proposal as part of the Resource Adequacy Enhancements stakeholder initiative to the CAISO Board in first quarter of 2021. The CAISO will then conduct a shadow analysis of the UCAP methodology during the 2022 resource adequacy year. The CAISO proposes that the UCAP paradigm become binding for the 2023 resource adequacy year to coincide with the start of procurement by the central procurement entities. This timing is important because it avoids multi-year procurement that could be split between the current net qualifying capacity and UCAP methodologies. The binding implementation timeline is also coordinated with the CAISO's other proposals for availability limited resource procurement, resource adequacy imports, and a forthcoming proposal on multi-year system and flexible capacity procurement.

D. Proposal 4: Resource Adequacy Imports

California must strike a balance between the need for sustainable, reliable, and dependable resource adequacy imports and the need for efficient and liquid markets recognizing that California competes for imported energy and transmission service across a broad and diverse west-wide market. Given California's long-standing and growing reliance on resource adequacy

[25] *See* section 4.3 of Attachment D for additional details regarding the CAISO's proposal.

imports to support reliability, the CAISO must ensure there is dependable resource adequacy import capacity and transfer capability secured in advance to meet California's capacity and energy needs, particularly as competition for supply tightens across the west.

Under current resource adequacy rules, the Commission and CAISO allow LSEs to enter into energy contracts with non-resource specific system resources whose energy can be transferred using non-firm transmission service across the entire delivery path to count as resource adequacy import capacity. Unfortunately, such arrangements provide inadequate assurance of reliability and deliverability and do not address speculative supply or double counting concerns.

Speculative supply and double counting concerns remain unresolved under the Commission's Track 1 decision in this proceeding. Under the rules adopted in the Track 1 decision, resource adequacy importers can continue to source and sell speculative capacity and fulfill resource adequacy must offer obligations using last-minute bilateral energy purchases. There is no assurance these bilateral purchases are anything but excess energy from resources that were never committed to California in the first instance and have no obligation to sell to California. When system resources are constrained across the west, there is no assurance this "excess energy" will still be available to meet California LSEs' needs. Instead it will more likely flow to the native load of the entities that paid for and committed to that capacity upfront. Furthermore, allowing resource adequacy import energy to flow on hourly non-firm transmission source-to-sink provides inadequate assurance the transmission transfer capability is sufficient to deliver energy to California, even if excess energy is available in the system. Under these circumstances, the Commission should transition to a resource adequacy import framework that requires resource-specific capacity dedicated solely to California and secured in advance using high priority transmission service to ensure secured power can actually flow to California, particularly during stressed west-wide system conditions.

Given these unresolved concerns, the Commission should adopt the CAISO's resource adequacy import proposal submitted in Track 1 of this proceeding, with the refinements discussed herein or ultimately adopted in the CAISO's ongoing Resource Adequacy Enhancements stakeholder initiative. This proposal will effectively address the concerns described above and better ensure the availability of dependable and dedicated imports to meet California's energy needs. The CAISO proposes a "bridge" year for the 2022 resource adequacy year with binding implementation for the 2023 resource adequacy year to allow a reasonable transition to the new resource adequacy import framework.

1. Background

The CAISO previously submitted a proposal for resource adequacy imports in Track 1 of this proceeding to address potential speculative import supply and double counting by limiting opportunities for physical withholding.[26] The CAISO further refined this proposal since its Track 1 filing. The changes made since the CAISO filed its Track 1 comments are detailed in the CAISO's fifth revised straw proposal.[27] The CAISO continues to work with stakeholders to refine and develop its resource adequacy imports proposal in its ongoing Resource Adequacy Enhancements initiative, and is currently scheduled to issue a Draft Final Proposal in October 2020. The CAISO will provide any necessary updates in its October 15 final proposal in this proceeding.

2. Proposal

The key elements of the CAISO's resource adequacy imports proposal are: (1) source specification, (2) minimum energy service requirements and attestations, and (3) minimum transmission service requirements. These three aspects are discussed in detail below.

a. Source Specification for Resource Adequacy Eligible Imports

The CAISO proposes that only source-specific imports should be eligible to provide resource adequacy capacity. Non-resource specific system resources would not be eligible to provide resource adequacy capacity. The three types of imports that should be eligible to provide resource adequacy import capacity are:

1. Non-dynamic resource-specific system resources, which can be:
    a. a single resource;
    b. a specified portfolio of resources within a single balancing authority area; or
    c. a balancing authority area's pool of resources.
2. Dynamically scheduled resource-specific system resources; and
3. Pseudo-tied resources.

Non-resource specific firm energy contracts cannot address speculative supply or double

[26] CAISO, Resource Adequacy Track 1 Proposal, R.19-11-009, February 28, 2020.
[27] *See* Section 4.1.6 in Attachment D.

counting concerns. As such, non-resource specific system resources are not a substitute for advanced procurement of real, physical and dedicated resource-specific capacity. Accordingly, contracts that do not identify or specify resources in support of the resource adequacy contract should not count as resource adequacy capacity. Economy energy contracts and related hedging mechanisms can help mitigate day-ahead and real-time market price risk, but they cannot ensure that real physical supply is dedicated to California in advance, which is the purpose of the resource adequacy program.

b. Energy Service Requirements and Attestation

The Commission should require all resource adequacy import contracts to have defined source specification demonstrating real, physical supply at the time of resource adequacy showings. Further, resource adequacy import contracts should include attestations that the physical resource adequacy import capacity is committed solely to California LSEs to serve California's reliability needs and has not been sold or committed to anyone else. Under current resource adequacy import rules, the CAISO and Commission cannot determine whether resource adequacy imports are double counted for load serving purposes. Under current resource adequacy program rules, neither LSEs nor import providers are required to provide evidence showing the their resource adequacy import capacity has not been sold to a third party or otherwise used to meet capacity obligations in another balancing authority area.

To address these concerns, the CAISO recommends the Commission require resource adequacy import capacity contracts to (1) include an attestation of source specification, (2) include an attestation that the resource adequacy import capacity is committed solely to the California LSE and has not been sold or committed to any other entity, and (3) specify energy service under Schedule C to the Western Systems Power Pool (WSPP) Agreement. These requirements will help verify that import contracts will provide California with high quality, dedicated capacity and energy services when needed.

Resource adequacy import capacity contracts should include an attestation of source specification from the importer. The source specification attestation should specify that the physical capacity from the resources to be relied upon to meet California resource adequacy requirements is procured at the time of the resource adequacy showings for the applicable resource adequacy showing period. As indicated above, the resource specificity requirement can be met by showing the resource adequacy import is supported either by (1) a single resource, (2) a portfolio of resources, or (3) a balancing authority area's pool of resources.

Resource adequacy imports should also be supported by an attestation that the resource adequacy import capacity that has been specified has not been sold, or otherwise committed, to any other entity for the same period.[28] The CAISO notes that other independent system operators and regional transmission organizations impose similar requirements to the two attestation requirements the CAISO proposes here.

To count as resource adequacy capacity, import contracts must provide source specification information and attestation by established deadlines for the applicable year-ahead and month-ahead resource adequacy showings. The Commission and CAISO can work with stakeholders to develop and refine specific attestation language through this Track 3.B proceeding and the CAISO's Resource Adequacy Enhancements initiative.

In addition, and separate from the transmission requirements discussed below, resource adequacy contracts should specify firm energy service under Schedule C to the WSPP Agreement. WSPP Service Schedule C defines procedures, terms, and conditions for providing Firm Capacity/Energy Sale or exchange service.[29] Service Schedule C service provides the ability to ensure that energy delivery from the contracted resources is supported by actual physical resources when the energy is needed. Providers of import resource adequacy should be required to attest that their contractual arrangements ensure the energy to be delivered under the contact will not be recallable to serve other contractual obligations and is not already committed to meet another balancing authority areas reliability requirements.

The CAISO recognizes there may be some additional costs associated with more rigorous source-specification requirements, but the additional reliability benefits outweigh those costs. In addition, requiring source specification for import resource adequacy resources' quality and

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[28] With the potential extension of the day-ahead market to EIM entities, the CAISO believes resource adequacy imports must, at a minimum, specify the source balancing authority area. The proposed source specification will help the CAISO verify that RA imports are not double counted for EIM entities' resource sufficiency tests. Without this rule, it would be possible for an EIM entity to count on capacity from a resource within its own balancing authority area to pass the EIM resource sufficiency evaluation, while also showing the resource as import resource adequacy to the CAISO. This is not an appropriate outcome because the resource is incapable of physically meeting both the source balancing authority area's needs *and* the CAISO's needs. The CAISO anticipates that requiring a designation of the source balancing authority area is a good first step, and the Commission is encouraged to support this step.

[29] See WSPP form agreement available at
http://www.wspp.org/pages/documents/01_25_20_current_effective_agreement.docx.

delivery obligations will treat such resources more comparably with internal resource adequacy resources. Adopting a source specification requirement for import resources will require host balancing authorities and suppliers to secure fuel and plan their resource commitments to meet their own needs and import commitments to the CAISO. Requiring forward source specification from real, physical capacity committed to serving only the CAISO will address speculative import supply and bidding behavior concerns by helping ensure actual physical resource capacity is secured to serve California's reliability needs.

c. Transmission Service Requirements

i. Recommendations

The CAISO recommends the Commission adopt a firm point-to-point transmission service requirement, source-to-sink, for all resource adequacy imports. Specifically, resource adequacy contracts should specify NERC Transmission Service Reservation Priority 7-F or 7-FN, as applicable, or comparable firm transmission service provided under a transmission provider's transmission service agreement or open access tariff. For reference, NERC's transmission service priorities are listed below in Table 3.[30]

Table 3: NERC Transmission Service Reservation Priorities

Transmission Service Reservation Priorities		
Priority	**Acronym**	**Name**
0	NX	Next-hour Market Service
1	NS	Service over secondary receipt and delivery points
2	NH	Hourly Service
3	ND	Daily Service
4	NW	Weekly Service
5	NM	Monthly Service
6	NN	Network Integration Transmission Service from sources not designated as network resources
7	F	Firm Point-to-Point Transmission
	FN	Network Integration Transmission Service from Designated Resources

If the Commission does not adopt a firm source-to-sink transmission requirement, it

[30] NERC transmission service reservation priority table found here: https://www.nerc.com/pa/rrm/TLR/Pages/Transmission-Service-Reservation-Priorities-.aspx

should, at minimum, require firm point-to-point transmission[31] on the last transmission line of interest (last leg) into CAISO balancing authority area. The CAISO also recommends requiring sufficient transmission service for other segments of the transmission path and will develop a specific recommendation on this point to incorporate into the October 15 final proposal. The CAISO is specifically considering whether to require 5-NM monthly service. This would ensure that import contracts secure monthly non-firm transmission a month at a time in alignment with California's monthly resource adequacy program. Under this framework, weekly, daily, hourly or lower priority non-firm transmission service reservation priorities would not be allowed for resource adequacy imports.

In addition, it is important to keep in mind that under this framework, the commitments made regarding the firmness of the energy arrangement, described above, would still hold, and would continue to provide greater assurances that committed import resource adequacy is actually deliverable when need. For example, in the event conditions in the greater northwest regions are tight and result in curtailments of non-firm transmission on those upper legs, the provider of resource adequacy imports is still obligated to provide the firm energy it committed to deliver or face penalties specified under the contract, which will provide the right incentive to either procure the adequate amount of firm transmission in those upper legs, or leverage other

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[31] Under the pro-forma OATT, which reflects the nature of transmission service throughout the West, firm transmission rights provides equivalent service to that provided to native load. Specifically, Section 13.6 states:

> In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

procurement options to serve the contract.

ii Other Independent System Operator (ISO) and Regional Transmission Operator Resource Adequacy Import Requirements

The most robust and secure transmission delivery requirement for resource adequacy imports would be to require firm point-to-point transmission service along the entire delivery path from the source to the CAISO balancing authority area sink and to require the commitment that the capacity and energy under the contractual arrangement is not recallable to serve other contractual arrangements or reliability commitments to other balancing authority areas. Other organized market regions generally have more stringent requirements. However, for the reasons discussed above, the CAISO believes that an alternative requiring firm transmission on the last leg of the transmission segment may be feasible in the Western Interconnection, as discussed above.

For context, the CAISO provides the following brief summaries of other ISO and RTO requirements for external capacity resources providing resource adequacy:

- ISO-NE requires that in support of new import capacity resources, the customer must submit "documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load;"[32] Import capacity must document that neighboring and intervening control areas will afford the capacity the same curtailment priority as native load.[33] ISO-New England can obtain information sufficient to show a generator's ability to deliver capacity.[34] External capacity must describe in detail how its capacity/energy will be delivered to the New England border and explain how such capacity/energy will be recognized by the control area with the same priority as native load.[35]

- MISO requires "demonstrating that there is firm transmission service from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability…;"[36] MISO also has external balancing authority area qualification options to ensure energy schedules from external resources are interrupted in a manner that is transparent and

[32] ISO New England, Transmission, Markets and Services Tariff, Section 13.1.3.5.1
[33] *Id.* at Section 13.2.3.5.3.1
[34] *Id*. at Section13.1.1.2.7.
[35] ISO New England Attachment M-Manual 20, Sections 12-13.
[36] MISO Tariff, Module E, Sheet 69A.3.1.c

supports reliability.[37] MISO has three resource adequacy import categories: specific generator in external balancing authority area,[38] slice of system,[39] and slice of system in a balancing authority area that coordinates with MISO regarding planning reserve qualifications and emergency procedures.

- NYISO requires a demonstration, to the satisfaction of the NYISO, that the UCAP is deliverable to the New York Control Area.[40] NYISO also requires that to participate as external installed capacity suppliers, external resources must demonstrate either (a) assurance the External Control Area in which the external resource located either will not recall or curtail for purposes of satisfying its own resource adequacy needs exports from that External Control Area in an amount equal to the amount of capacity the resource is proving to the NYCA or (b) in the case of Control Area system Resources, the External Control Area will afford the NYCA Load the same curtailment priority that it affords its own Control Area Load ."[41]

- PJM imposes different requirements depending on how the external resource participates in the capacity market that can be either as rigorous as a pseudo-tie arrangement or as is required in most other areas, that the resource have firm transmission service to the PJM border.[42]

  SPP requires Firm Capacity to be supported firm service from external resource to load.[43] Firm Power must be supported by firm service and must be available in a manner comparable to power delivered to native load customers.

iii Discussion of the CAISO's Proposal

In the Fifth Revised Straw Proposal, the CAISO expressed its preference to require firm, source-to-sink transmission service for resource adequacy imports. The CAISO also described an alternative for consideration if a firm point-to-point transmissions service on the entire delivery path is unwarranted at this time whereby firm service would only be required on the "last leg of interest" into the CAISO's balancing authority area.

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[37] MISO Business Practice Manual 11, Section 4.2.5.
[38] If MISO is in an emergency service will be interrupted only if the specific generator is on an outage.
[39] Curtailment is pro-rata with load in external BAA if the external BAA is in emergency conditions.
[40] NYISO MST - Market Administration and Control Area Services Tariff (MST), Section 5.12.2.1 and NYISO ICAP Manual, Section 4.9.3.2.
[41] NYISO MST - Market Administration and Control Area Services Tariff (MST), Section 5.12.2.1; NYISO ICAP Manual, Section 4.9.1.
[42] PJM Manual 18: PJM Capacity Market, Section 4.2.2
[43] SPP Open Access Transmission Tariff, Attachment AA, Sections 7.3 and 7.5.

Stakeholders supporting a firm, source-to-sink firm transmission requirement have stated that although there may be a reasonable degree of probability a resource with non-firm service can support resource adequacy imports in many instances that may not be the case when system conditions are strained and external entities are competing for limited transmission capacity.[44] Such entities argued these deficiencies with non-firm rights potentially could render the transmission insufficient to support resource adequacy imports.

Other stakeholders opposed requiring a firm, source-to-sink transmission service, arguing such a requirement affords less flexibility, is unnecessary, and is more costly. They suggested firm service is generally more important in the constrained areas of the transmission grid, but is unnecessary elsewhere. These stakeholders claimed the Bonneville Power Administration (BPA) system, which is a key path for imports into California, functions like a "funnel." BPA's northern network is a broader, more robust, and non-radial transmission network and the southern intertie portion funnels radially down to key transmission paths from the BPA system into the CAISO balancing authority areas.[45] These stakeholders argued that only the southern intertie portion of the BPA system is constrained and requires greater certainty and firmness to ensure deliverability to the CAISO balancing authority area.

After assessing these arguments, the CAISO continues to recommend the Commission require firm point-to-point transmission service. However, in the alternative, the Commission could consider adopting an alternative transmission service framework whereby, at a minimum, firm point-to-point transmission service would be required only on the "last line of interest" to the CAISO boundary, *i.e*. the last leg. For example, on BPA's system, these "last lines" represent BPA's southern interties. This compromise would allow resource adequacy importers to maintain flexibility and rely on the more open nature of BPA's northern network; although, it would provide technically inferior transmission service compared to firm point-to-point transmission service along the entire delivery path.

The CAISO continues to consider the necessary transmission service requirements for other segments of the transmission path. Specifically, the CAISO is considering whether to

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[44] Stakeholder comments on the CAISO's RA Enhancements Initiative can be found here: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Resource-adequacy-enhancements

[45] For example, the Big Eddy to North of Oregon Border (NOB) and John Day to California-Oregon Border (COB) paths.

require resource adequacy import contracts specify 5-NM monthly transmission service reservation priority, or comparable monthly priority service, for all other segments along the transmission path. This is important because E-tags with mixed transmission priorities default to their lowest priority segment when the transmission provider must enact curtailments. In other words, a transmission schedule with firm 7-F priority on the last leg, but a lower priority transmission segment in the delivery path, will be cut consistent with the lower service reservation priority. Thus, a non-firm monthly transmission service reservation will maintain priority over weekly, daily, and hourly non-firm service reservations. The Commission and CAISO should ensure that non-firm transmission service segments ensure sufficient transfer capability to California. The CAISO will provide update and refine its recommendation regarding transmission service requirements in its October 2020 final proposal.

iv. Policy Implementation

The Commission should consider adopting a two-step implementation process for new resource adequacy import requirements. The first step should be to use the 2022 resource adequacy compliance year as a bridge to transition to the new framework. For 2022, the Commission should encourage LSEs to provide resource adequacy import contracts with source specification information and firm transmission as outlined above. Load-serving entities should also use 2022 to modify existing import contracts or enter into new ones as appropriate. Step two would implement full compliance with the resource adequacy import proposal for the 2023 resource adequacy compliance year.

v. Summary

The Commission and the CAISO should work collaboratively to implement the following resource adequacy import requirements:

1. Eligible source specific import types:
    a. Non-dynamic resource-specific system resources that are:
        i. a single resource;
        ii. a specified portfolio of resources within a single balancing authority area; or
        iii. a balancing authority area's pool of resources.
    b. Dynamically scheduled resource-specific system, and
    c. Pseudo-tied resources.

2. Energy Service Requirements:
    a. WSPP Agreement Service Schedule C firm capacity/energy service; and
    b. Accompanying attestation requirements to show capacity is committed solely to the CAISO.
3. Transmission Service Requirements:
    a. Preferred approach: Firm point-to-point transmission service across entire delivery path with transmission reservation service priority 7-F/7-FN, or equivalent.
    b. Alternative approach: Firm point to point transmission service on last leg to CAISO balancing authority area with 7-F priority or equivalent and adequate transmission service on all intervening lines of interest, potentially specifying transmission service priority 5-NM, or an equivalent monthly service priority.
4. Implementation:
    a. Two-step process with 2022 as a transition year and full compliance in 2023 under the new resource adequacy import framework.

E. Informational Update: Revised Flexible Capacity Product and Multi-year System and Flexible Capacity Requirements

The CAISO does not have a proposal at this time regarding new flexible or multi-year procurement requirements due to ongoing market design work. However, the CAISO continues to support the core tenets of its 2018 testimony regarding the need for multi-year system, flexible, and local capacity procurement. The CAISO is currently developing important market rule changes in its Resource Adequacy Enhancements and Day-Ahead Market Enhancements (DAME) stakeholder initiatives. In these two initiatives, the CAISO is seeking to develop a day-ahead imbalance reserve product to address deviations between the day-ahead and real-time markets and the forward procurement corollary. These two initiatives will effectuate significant revisions to the existing flexible resource adequacy construct. The CAISO requests the Commission allow additional time to discuss both a revised flexible capacity product and multi-year system and flexible capacity requirements in Track 4 of this proceeding or another track that would allow for the adoption of a multi-year system and flexible capacity requirements for the 2023 resource adequacy year.

1. Background

In Decision (D.) 17-09-020, the Commission adopted a three-year forward local resource adequacy requirements.[46] In alignment with this decision, the CAISO recommends the Commission adopt a holistic multi-year resource adequacy framework that includes three-year forward procurement requirements for system and flexible capacity. The CAISO continues to believe in the core tenets of its 2018 testimony on Track 2: "a multi-year procurement framework for all three capacity products provides significant benefits, which include simplifying multi-year capacity allocations, ensuring more optimal and effective resource procurement, and informing the more fundamental challenge of providing for orderly retirement of non-essential gas-fired generation."[47]

2. Ongoing CAISO Market Design Work

The CAISO is addressing multi-year system and flexible capacity in two separate phases. The first phase is changing the flexible capacity requirement to align with meeting the day-ahead imbalance reserve requirements discussed in the DAME stakeholder initiative.[48] The CAISO has made significant progress in the first phase to develop the imbalance reserve product. The second phase will build from this work to establish multi-year flexible and system capacity requirements and will be discussed in the future in the Resource Adequacy Enhancements stakeholder initiative and subsequent tracks in this proceeding.[49]

The CAISO is proposing to reconsider flexibility needs based on 15-minute interval ramping capabilities in two interrelated efforts instead of the existing three-hour net load requirement. In the DAME stakeholder initiative, the CAISO's proposed imbalance reserve product ensures both upward and downward capacity is available to the real-time markets to address differences between the day-ahead and fifteen minute markets caused by time granularity differences and forecast error. Instead, the imbalance reserve is a market mechanism that will more effectively use flexible resource adequacy capacity in the day-ahead and real-time markets. Although, the imbalance reserve does not set the flexible requirement for the resource adequacy

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[46] See the Proposed Decision, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M270/K469/270469481.PDF at pg. 20-22.
[47] Filed September 28, 2017, CAISO Track 2 Testimony, Corrected Chapter 2: Multi-year Resource Adequacy Procurement Requirements, pg. 1.
[48] See https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements
[49] See https://stakeholdercenter.caiso.com/StakeholderInitiatives/Resource-adequacy-enhancements

program, it will be the basis for setting the Flexible Capacity requirements and how resources count towards meeting the requirement. The Flexible Capacity requirement would be based on each LSE's share of the forecast monthly peak imbalance reserve requirement. The flex resource adequacy counting rules would change from what a resources can ramp in three hours to what a resource can ramp in 15 minutes. These are significant changes to the existing product and will require Commission adoption.

The CAISO is still in the process of developing important aspects of both the DAME and Resource Adequacy Enhancements proposals, including as the historical baseline used to set the requirements and the effective flexible capacity counting rules for intermittent renewables and storage resources. The CAISO urges interested parties, including Commission Energy Division staff, to actively participate in both the DAME and Resource Adequacy Enhancements stakeholder initiatives.

Since the issuance of D.17-09-020, the need for a multi-year forward system capacity procurement has grown more acute, as indicated by the system capacity shortfall procurement of 3,300 MW authorized under D.19-11-016 at the end of 2019. This emergency procurement, which the CAISO supported, notably addressed *peak system* capacity shortfalls in the resource adequacy program from 2021 through 2023. The Commission authorized the incremental capacity through the procurement track of the integrated resource plan (IRP) proceeding because the resource adequacy program does not have a forward capacity mechanism to address peak system needs beyond a single year forward. On the other hand, the CAISO's operational analysis showed that the greatest *system energy* need occurred in the hours after sunset when summer loads remain high, but solar resource production wanes. The maximum hourly energy need in the CAISO's conservative analysis was 4,400 MW in 2021 and 4,700 MW in 2022.[50] Lastly, the CAISO has consistently urged the Commission to authorize resource procurement by the end of summer 2020—with resources in place starting in 2024—to replace the loss of the Diablo Canyon Nuclear Power Plant (Diablo Canyon).[51] It is critical the Commission establish a multi-year system and flexible capacity program by the 2023 resource adequacy year to ensure there is sufficient forward visibility, planning, and procurement to address Diablo Canyon

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[50] CAISO Reply Comments, R.16-02-007, August 12, 2019, p. 2.
[51] CAISO Reply Comments on Proposed Schedule, R.20-05-003. July 24, 2020,pp 2-3

retirement and the resulting operational needs of the grid.

The CAISO continues to develop its proposal to ensure alignment between its stakeholder initiatives and plans to provide a full multi-year procurement requirement proposal to the Commission in the near future. The CAISO requests the Commission allow for additional time to discuss redesigning flexible resource adequacy counting rules and requirements, as well as multi-year system and flexible capacity procurement, in Track 4 or another track next year. The schedule should enable adopting both the revised flexible capacity construct and a multi-year system and flexible capacity requirement effective for the 2023 resource adequacy year.[52] This date is significant because it purposefully aligns implementation of new flexible resource adequacy counting rules and requirements and multi-year system and flexible capacity procurement with the start of the CAISO's DAME initiative, procurement by the central procurement entities, and implementation of the CAISO's availability limited resource, UCAP, and resource adequacy import proposals discussed above.

III. Conclusion

The CAISO appreciates the opportunity to submit proposals.

Respectfully submitted,

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Date: August 7, 2020

[52] The CAISO notes that adoption of the revised Flexible Capacity construct is required prior to adopting multi-year flexible capacity obligations. However, multi-year system obligations should align with the implementation of the CAISO's proposed UCAP methodology.

Attachment A

E3 ELCC Study
May 27, 2020

Energy+Environmental Economics

Demand Response ELCC

CAISO ESDER Stakeholder Meeting

5.27.20

Zach Ming, Director

Vignesh Venugopal, Consultant

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Overview

Background

+ California has a unique approach to capacity procurement, where the CPUC administers a Resource Adequacy (RA) program to ensure sufficient resources to maintain an acceptable standard of reliability, but the CAISO retains ultimate responsibility for the reliable operation of the electricity system
+ The CAISO wants to ensure DR is properly valued in the Resource Adequacy program

Project

+ The CAISO retained E3 to investigate the reliability contribution of DR relative to its capacity value in the CPUC administered RA program
+ To the extent that DR is overvalued, the CAISO asked E3 to suggest solutions to issue
+ E3 provided technical analysis to support the CAISO in this effort

Disclaimer required by the California Public Utilities Commission

This report has been prepared by E3 for the California Independent System Operator (CAISO). This report is separate from and unrelated to any work E3 is doing for the California Public Utilities Commission. While E3 provided technical support to CAISO preparation of this presentation, E3 does not endorse any specific policy or regulatory measures as a result of this analysis. The California Public Utilities Commission did not participate in this project and does not endorse the conclusions presented in this report.

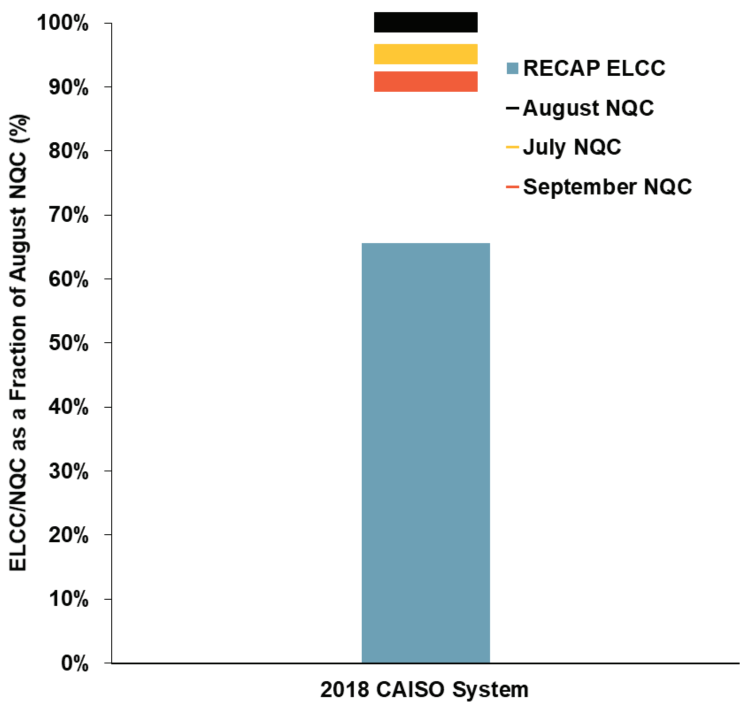
Outline

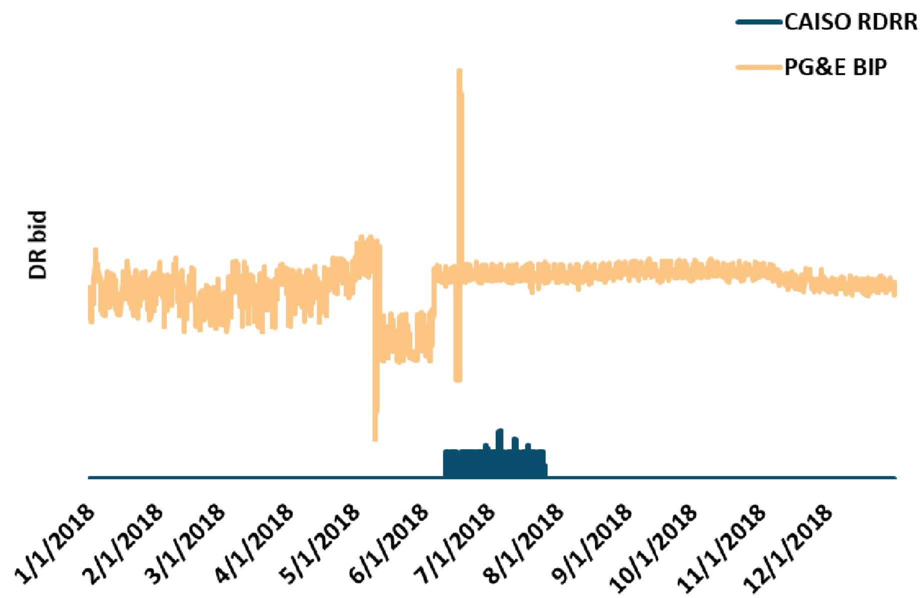
- Refresher on March 3 CAISO stakeholder meeting presentation
- Background on ELCC
- Performance of Existing DR
- Characteristics of DR Needed for ELCC
  - Time availability
  - # of calls / duration of calls
  - Penetration of DR
- Incorporating DR ELCC into Existing CPUC RA Framework
- Questions

Acronyms

Acronym	Name	Description
API	Agricultural and Pumping Interruptible	DR program to suspend agricultural pumping
BIP	Base Interruptible Program	Participants are offered capacity credits for reducing their demand up to a pre-determined level in response to an event call
CBP	Capacity Bidding Program	DR program where aggregators work on behalf of utilities to enroll customers, arrange for load reduction, receive and transfer notices and payments
DR	Demand Response	Reductions in customer load that serve to reduce the need for traditional resources
ELCC	Effective Load Carrying Capability	Equivalent perfect capacity measurement of an intermittent or energy-limited resource, such as DR
LCA	Local Capacity Area	Transmission constrained load pocket for which minimum capacity needs are identified for reliability
LIP	Load Impact Protocol	Protocols prescribed by the CPUC for accurate and consistent measuring (and forecasting) of DR program performance
LOLP	Loss of Load Probability	Probability of a load shedding event due to insufficient generation to meet load + reserve requirements
NQC	Net Qualifying Capacity	A resource's contribution toward meeting RA after testing, verification, and accounting for performance and deliverability restrictions
PDR	Proxy Demand Response	Resources that can be bid into the CAISO market as both economic day-ahead and real-time markets providing energy, spin, non-spin, and residual unit commitment services
PRM	Planning Reserve Margin	Capacity in excess of median peak load forecast needed fore reliability
RA	Resource Adequacy	Resource capacity needed for reliability
RDRR	Reliability Demand Response Resource	Resources that can be bid into CAISO market as supply in both economic day-ahead and real-time markets dispatched for reliability services
SAC	Smart AC Cycling	Direct air conditioner load control program offered by PG&E
SDP	Summer Discount Plan	Direct air conditioner load control program offered by SCE
SubLAP	Sub-Load Aggregation Point	Defined by CAISO as relatively continuous geographical areas that do not include significant transmission constraints within the area

Refresher on March 3 CAISO ESDER Meeting



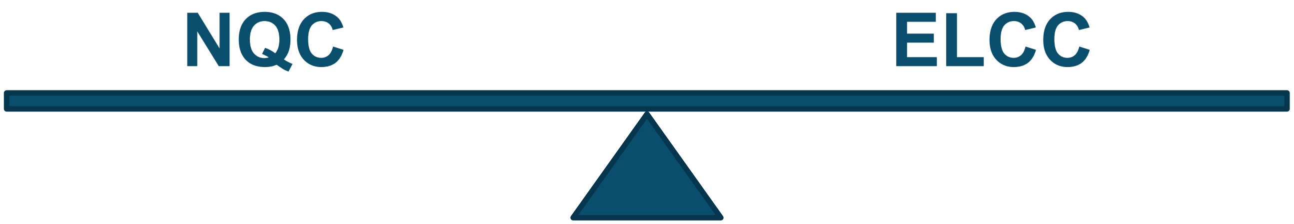


Established disconnect between ELCC and NQC

Provided E3 thoughts on how to match CAISO and utility DR bid data as well as techniques to extend this data over multiple historic weather years. Both points were addressed with the 2019 data.

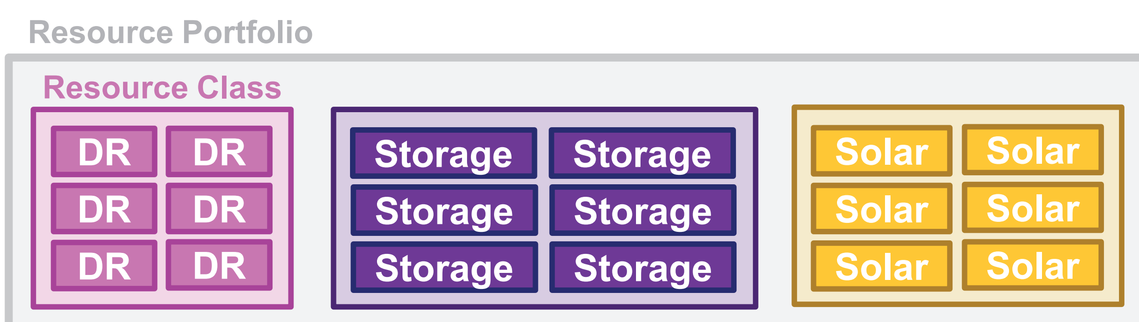
Key Questions to Answer

1) How are demand response programs performing today, relative to what they are being credited for?



2) What characteristics of demand response are needed today and in the future?

3) How should a resource adequacy program be designed to allocate and credit both DR in aggregate and individual DR programs?



Background on ELCC

Effective Load Carrying Capability (ELCC)

+ **Effective Load Carrying Capability (ELCC) is a measure of the amount of equivalent perfect capacity that can be provided by an intermittent or energy-limited resource**
  - **Intermittent resources:** wind, solar
  - **Energy-limited resources:** storage, demand response
+ **Industry has begun to shift toward ELCC as best practice, and the CPUC has been at the leading edge of this trend**

1 Calibrate existing system to target LOLE standard

If necessary, add or remove "perfect capacity" to achieve target standard

2 Add desired resource to portfolio

Addition of new source of generation will decrease LOLE relative to measurement in Step 1

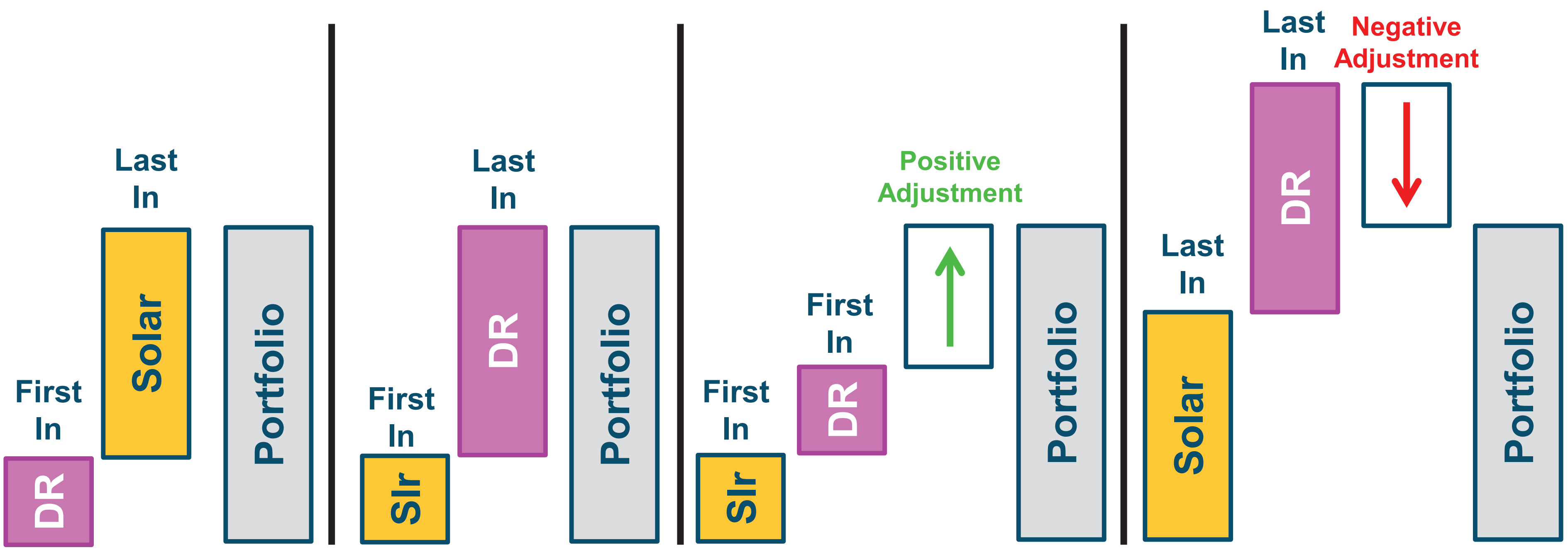
3 Remove perfect capacity until target LOLE is restored

Removal of perfect capacity results in increase in LOLE until original target is met

A resource's ELCC is equal to the amount of perfect capacity removed from the system in Step 3

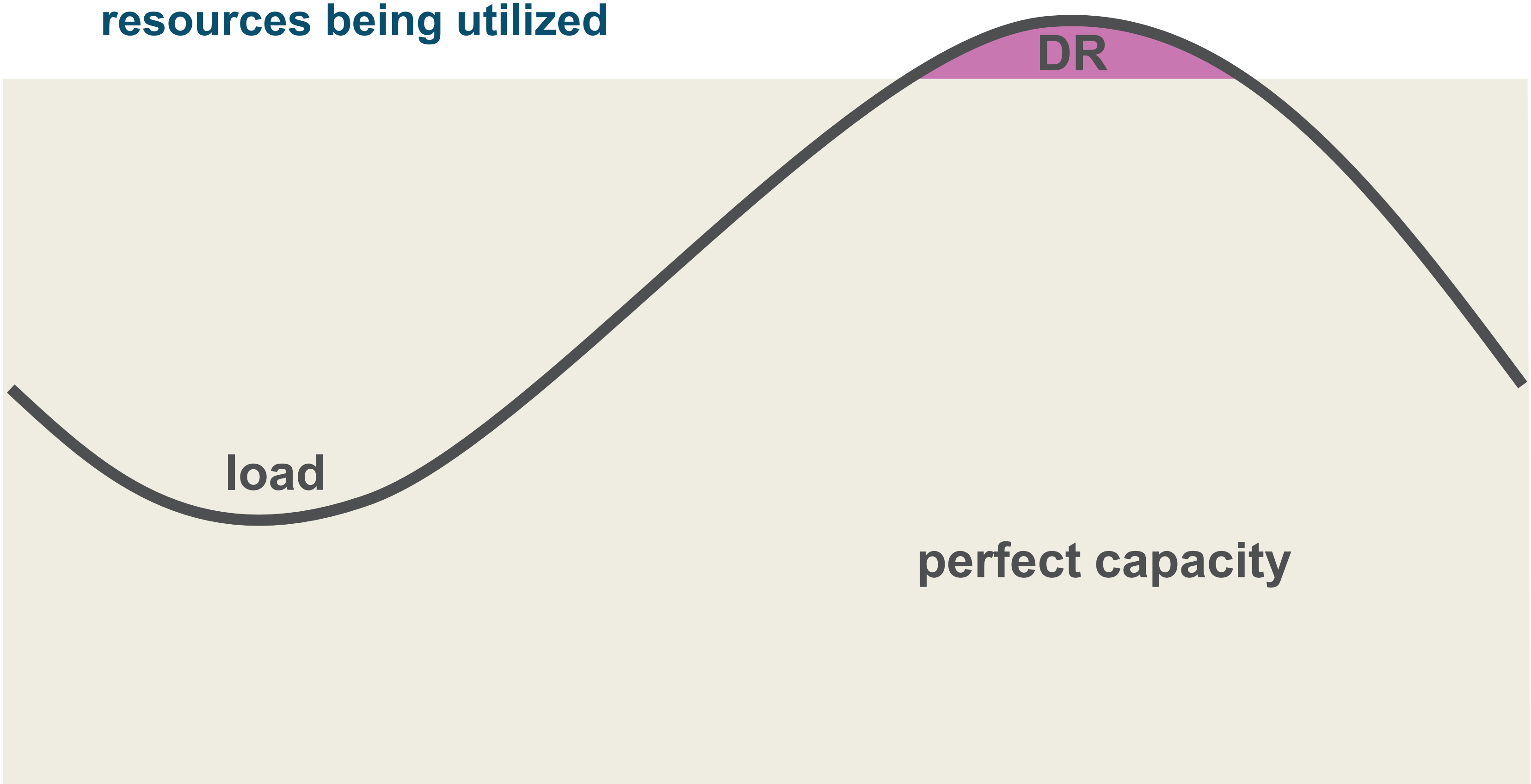
Measuring ELCC

+ **There are multiple approaches to measuring the ELCC of a resource(s)**
  - **Portfolio ELCC:** measures the combined ELCC of all intermittent and energy-limited resources on the system
  - **First-In ELCC:** measures the marginal ELCC of a resource as if it were the only intermittent or energy-limited resource on the system, thus ignoring interactive effects
  - **Last-In ELCC:** measures the marginal ELCC of a resource after all other intermittent or energy-limited resources have been added to the system, capturing all interactive effects with other resources



“First-In” ELCC

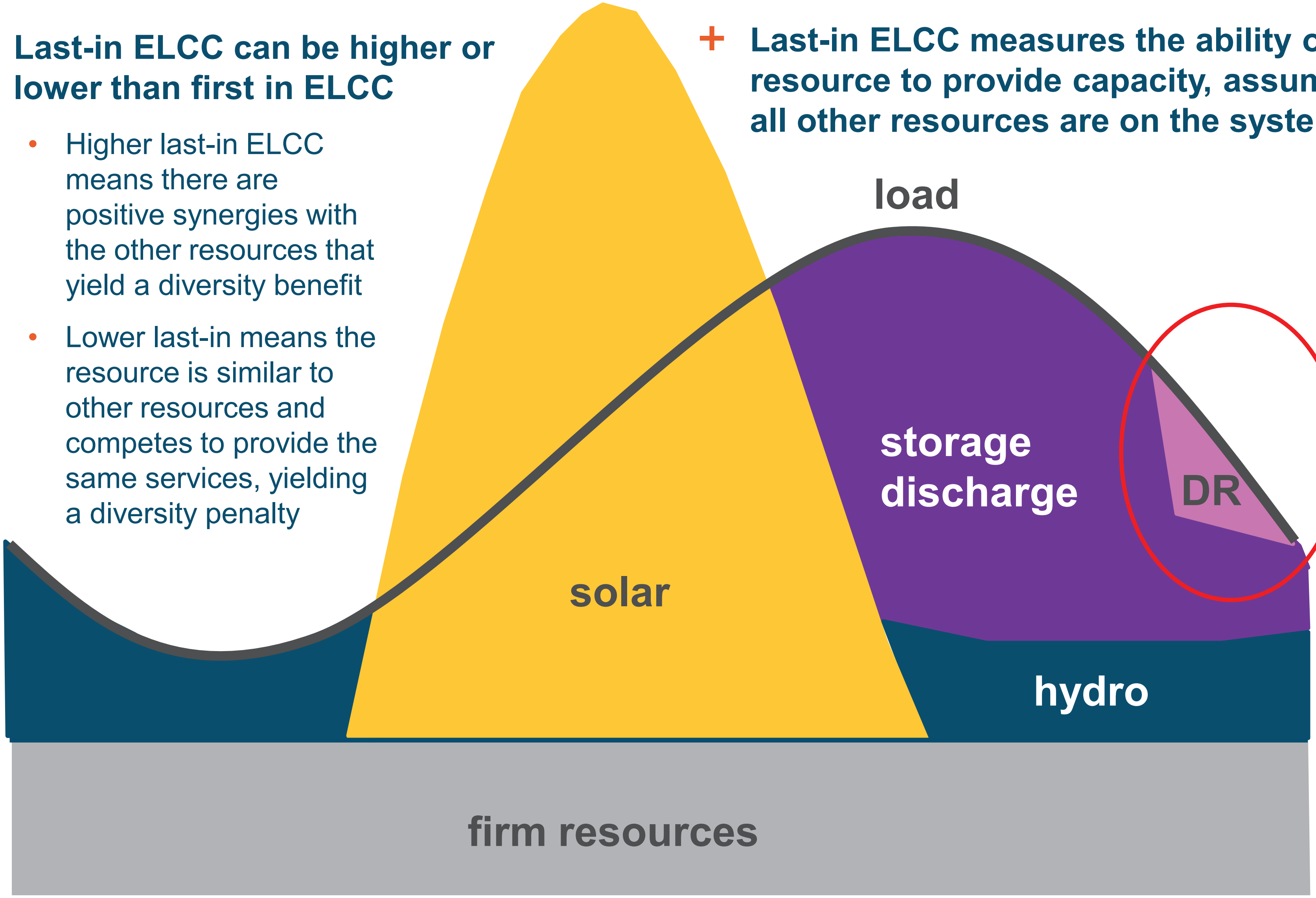
- First-in ELCC measures the ability of a resource to provide capacity, absent any other resource on the system
- This measures the ability of a resource to “clip the peak” and is often analogous to how many industry participants imagine capacity resources being utilized



"Last-In" ELCC

+ **Last-in ELCC can be higher or lower than first in ELCC**
  - Higher last-in ELCC means there are positive synergies with the other resources that yield a diversity benefit
  - Lower last-in means the resource is similar to other resources and competes to provide the same services, yielding a diversity penalty

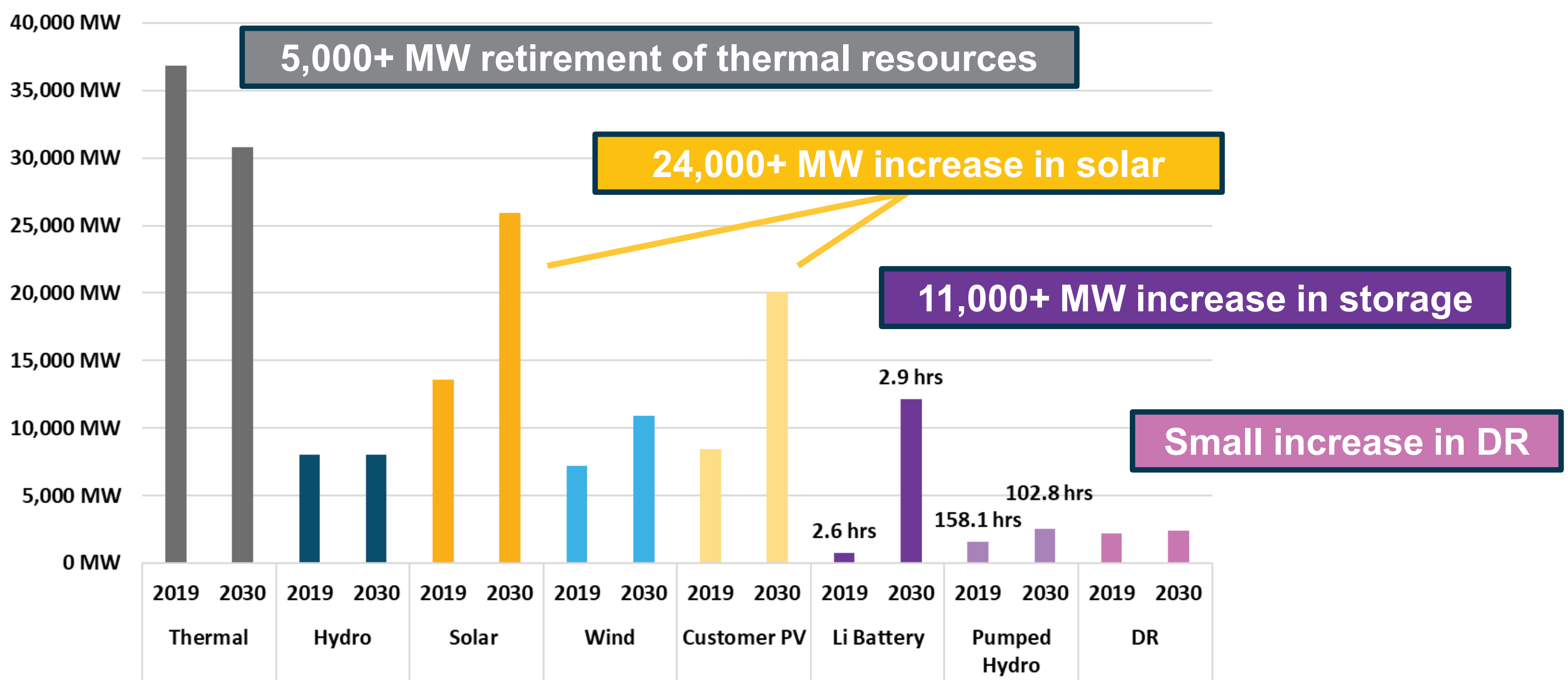
+ **Last-in ELCC measures the ability of a resource to provide capacity, assuming all other resources are on the system**



Today (2019) vs. Future (2030)

- E3 analyzed the value of DR to the CAISO system today (2019) and the future (2030) to assess how coming changes to the electricity system might impact value
- Primary changes are on the resource side (shown below) with modest changes to loads (49 GW 2019 peak load vs 53 GW 2030 peak load)

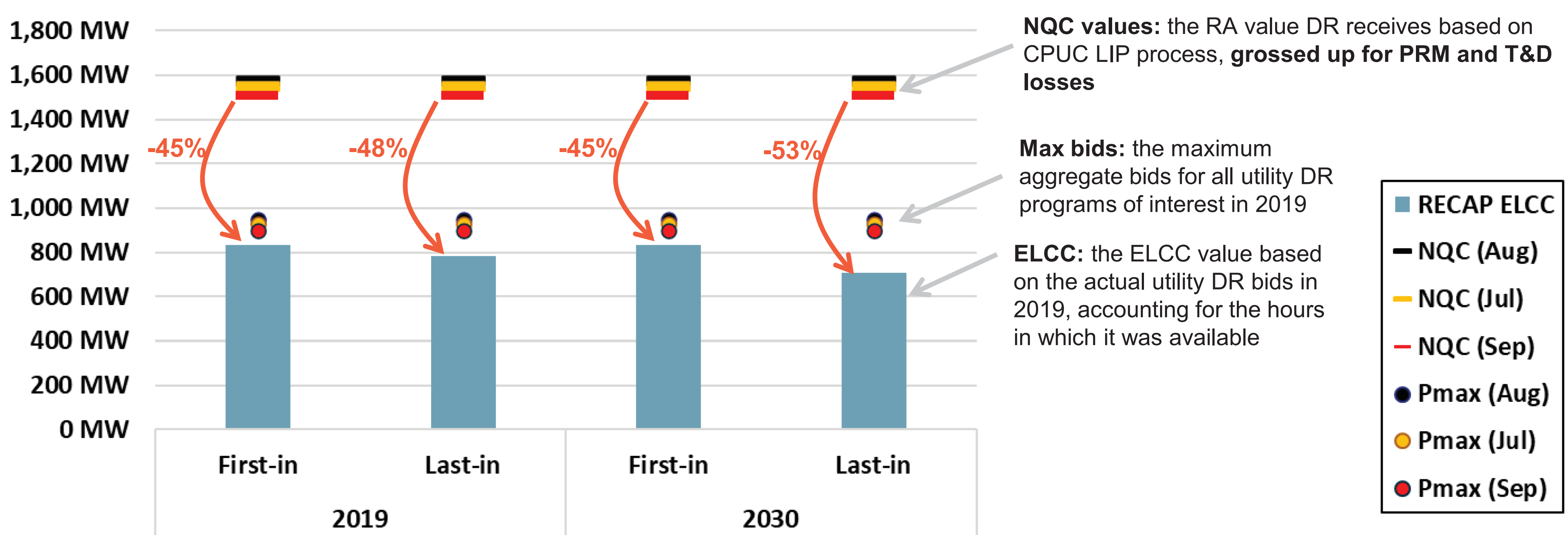
2019 and 2030 CAISO Resource Portfolio



Source: CPUC Integrated Resource Plan (IRP) Reference System Plan (RSP)

Performance of Existing PG&E and SCE event-based DR Programs

+ **Demand response (DR) resource adequacy qualifying capacity is currently calculated using the load impact protocols (LIP), which are performed by the utilities under the oversight of the CPUC**
  - LIP uses regression and other techniques to estimate the availability of demand response during peak load hours
+ **E3 has analysis suggests that LIP overvalues the capacity contribution DR relative to ELCC by 40%+ for two reasons:**
  1) DR does not bid into the CAISO market, in aggregate, at levels equal to its NQC value
  2) The times when DR is bid are either not at optimal times or not for long enough to earn full ELCC value



Load impacts are grossed up for transmission and distribution losses, as also the 15% PRM, owing to demand response being a demand reduction measure

$NQC = LI * 1.15\,(PRM) * T\&D\ loss\ factor$[1]

Load impacts for the year 2019 are referenced from the CPUC's RA Compliance documents[2]

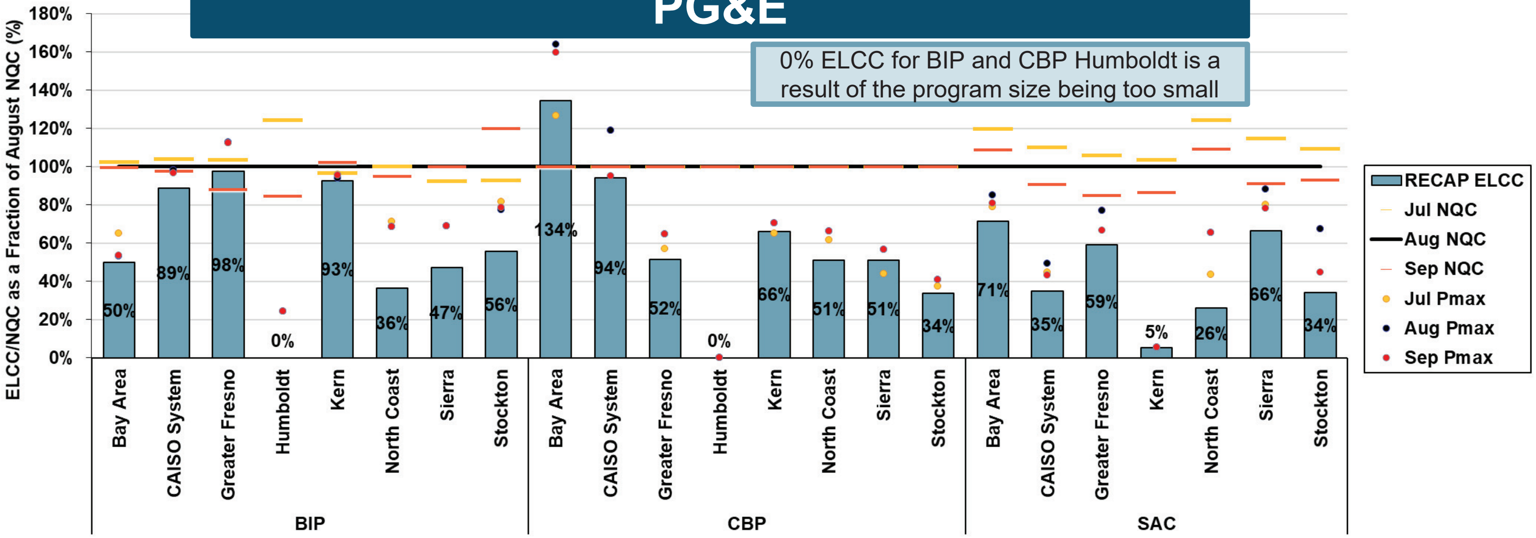
Load impacts are defined on an LCA level from 1 pm to 6 pm, Apr to Oct, and from 4 pm to 9 pm in the rest of the year, both with and without line losses

[1] CPUC 2019 RA Guide

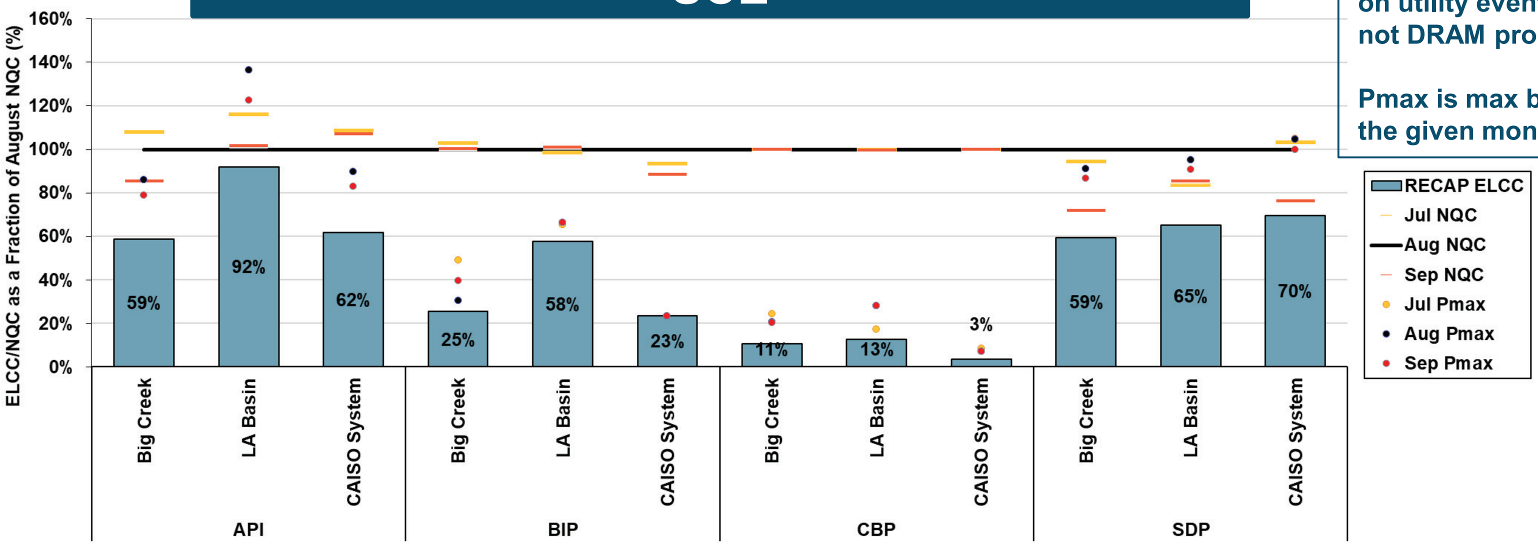
[2] CPUC 2019 IoU DR Program Totals

First-in ELCC of PG&E and SCE Programs

PG&E



SCE

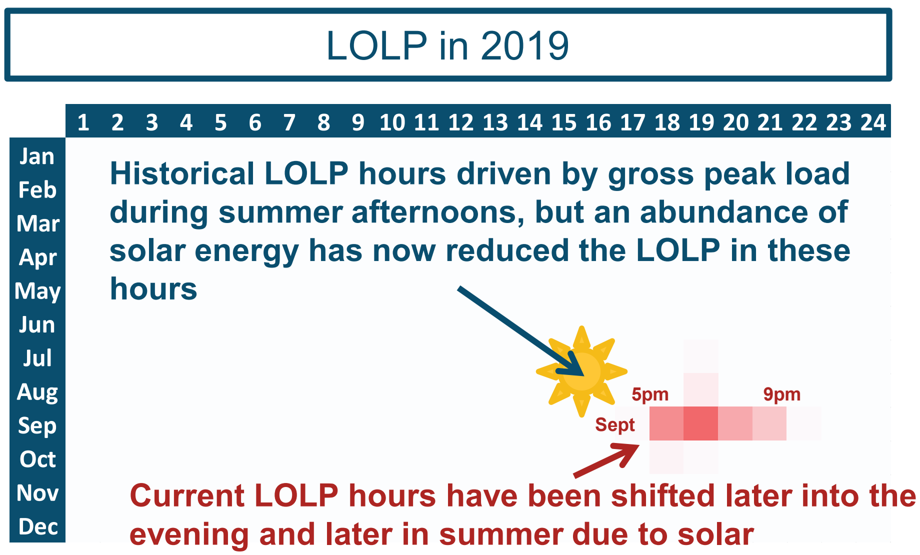


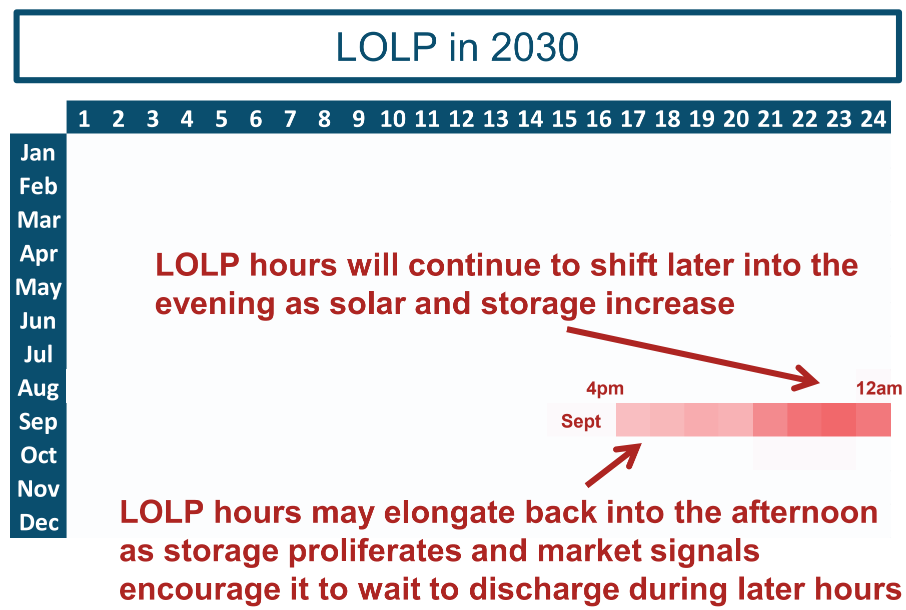
These results just focus on utility event-based DR, not DRAM programs

Pmax is max bid placed in the given month

Time Window Availability Needs for DR in 2019 & 2030

+ Month/hour (12x24) loss of load probability heat maps provide a quick overview of “high risk” hours
+ Key findings from this project are showing that strong interactions between storage and DR may elongate the peak period by 2030

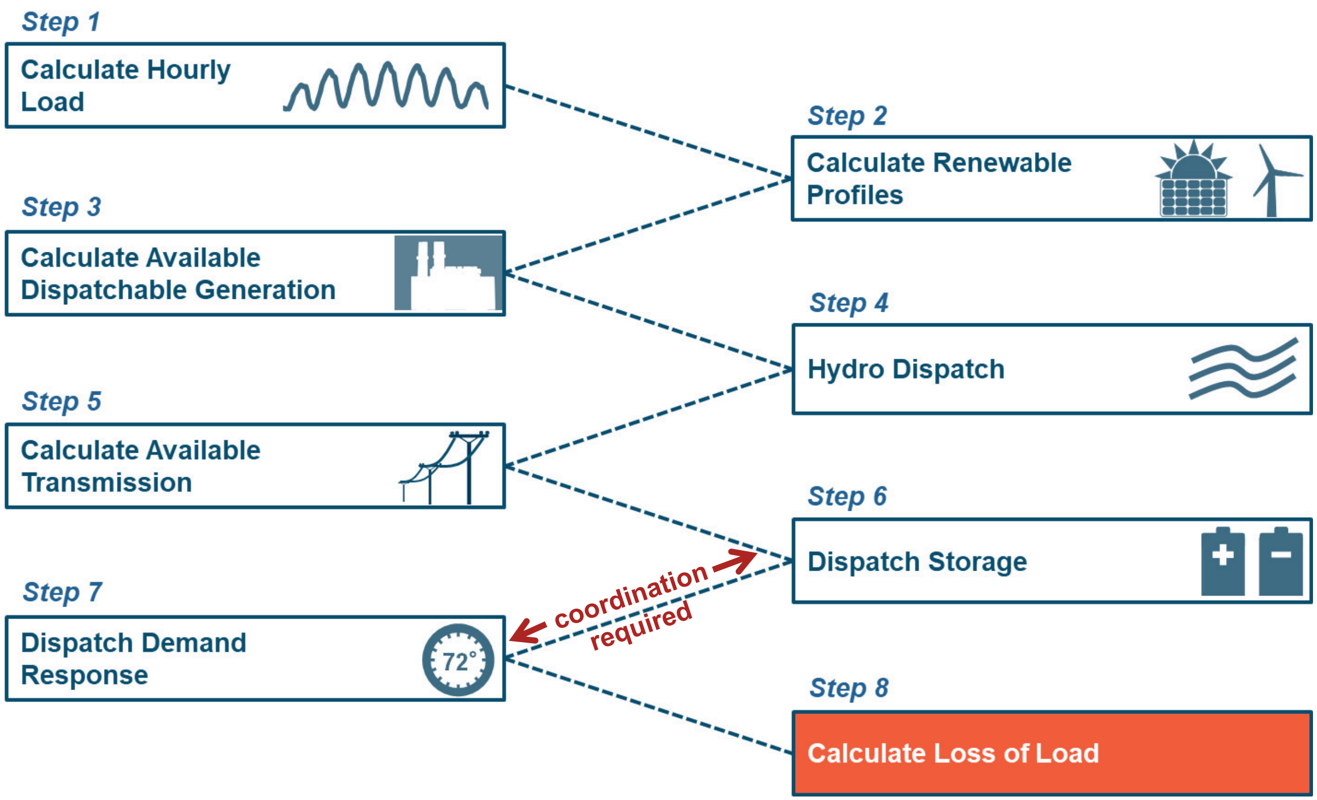




DR Interaction with Storage

- Historically, DR is dispatched as a resource of "last resort" which is how RECAP dispatched DR
- A system with high penetrations of storage require much more coordination in the dispatch of DR and storage in order to achieve maximum reliability

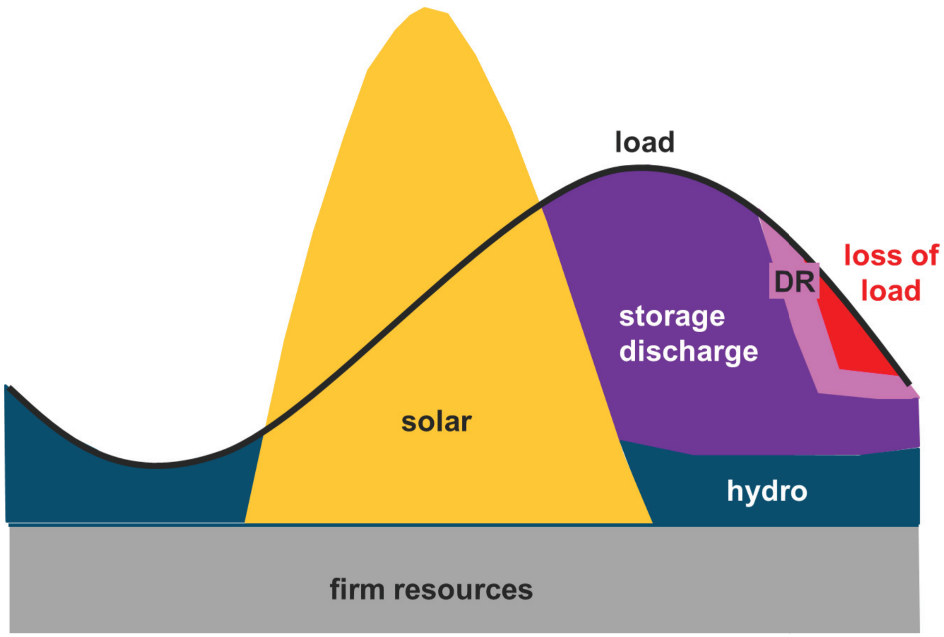
E3 RECAP Model Methodology



Last Resort vs. Optimal Dispatch

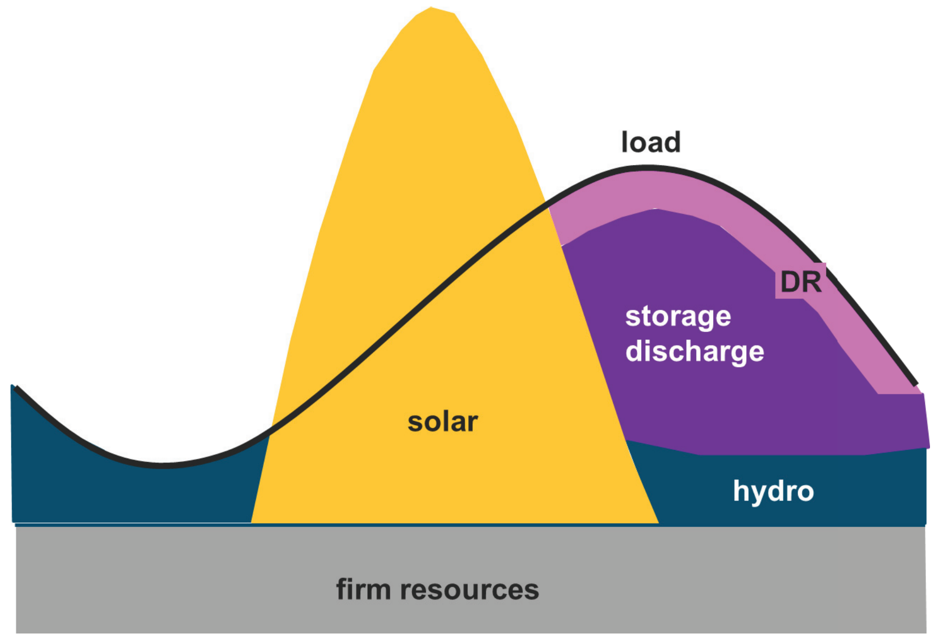
DR as Resource of Last Resort

When DR is dispatched as the resource of last resort, there is loss of load



DR Dispatch to Delay Storage Discharge

Preemptively dispatching DR to delay storage discharge eliminates loss of load event



Key takeaway: DR should be dispatched to delay storage discharge on days with potential loss of load

Call and Duration ELCC Results

First-in ELCC

2019

ELCC (% of nameplate)		Max annual calls: 1	2	4	5	10	15	20
Max call duration (hrs)	1	46%	50%	51%	51%	51%	51%	51%
	2	63%	73%	78%	78%	78%	78%	78%
	4	70%	81%	94%	95%	95%	95%	95%
	6	70%	81%	94%	95%	95%	95%	95%
	8	70%	81%	94%	95%	95%	95%	95%

No interactions with storage – therefore no expected significant differences

2030

ELCC (% of nameplate)		Max annual calls: 1	2	4	5	10	15	20
Max call duration (hrs)	1	41%	43%	43%	43%	43%	43%	43%
	2	60%	65%	65%	65%	65%	65%	65%
	4	72%	91%	95%	95%	95%	95%	95%
	6	73%	92%	98%	98%	98%	98%	98%
	8	73%	92%	98%	98%	98%	98%	98%

Last-in ELCC

2019

ELCC (% of nameplate)		Max annual calls: 1	2	4	5	10	15	20
Max call duration (hrs)	1	59%	73%	73%	73%	73%	73%	73%
	2	74%	90%	94%	94%	94%	94%	94%
	4	77%	98%	100%	100%	100%	100%	100%
	6	77%	98%	100%	100%	100%	100%	100%
	8	77%	98%	100%	100%	100%	100%	100%

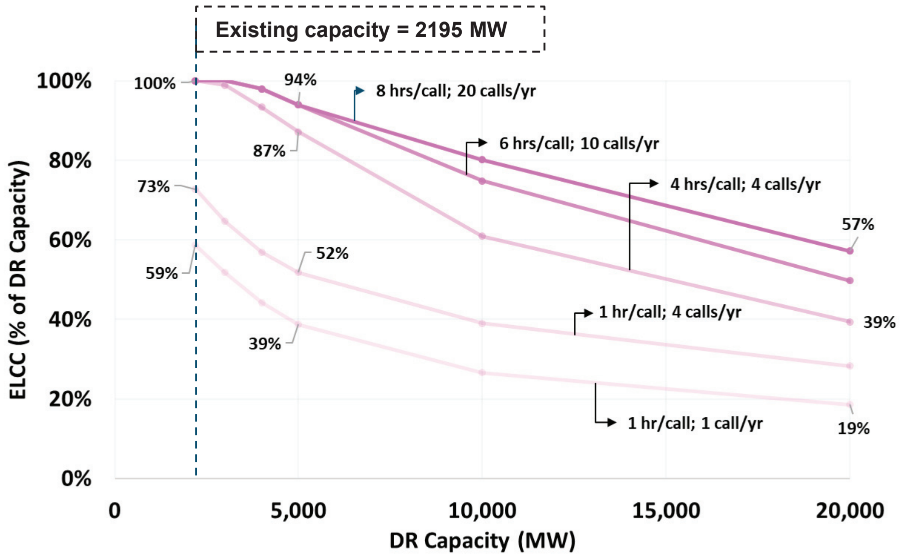
Significant degradation in last-in ELCC in 2030 is driven by saturation of energy-limited resources, primarily storage

2030

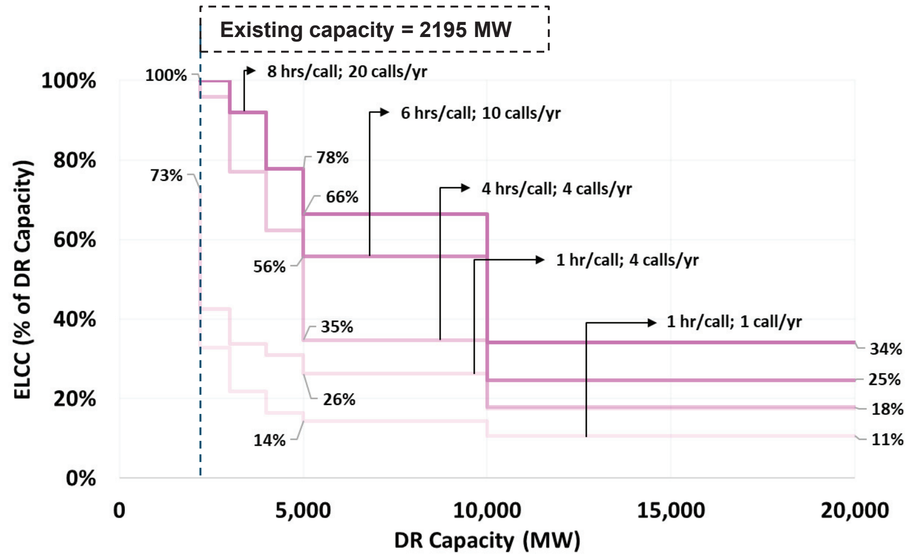
ELCC (% of nameplate)		Max annual calls: 1	2	4	5	10	15	20
Max call duration (hrs)	1	35%	37%	37%	37%	37%	37%	37%
	2	44%	49%	49%	49%	49%	49%	49%
	4	52%	65%	69%	69%	69%	69%	69%
	6	56%	77%	77%	77%	77%	77%	77%
	8	75%	91%	93%	93%	93%	93%	93%

DR ELCC Performance at Increasing Penetrations (2019)

Average Last-in ELCC



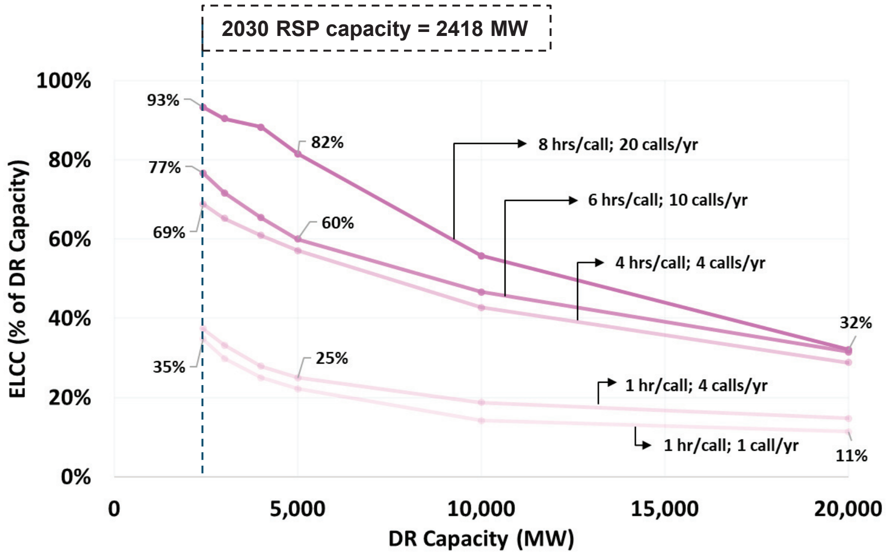
Incremental Last-in ELCC



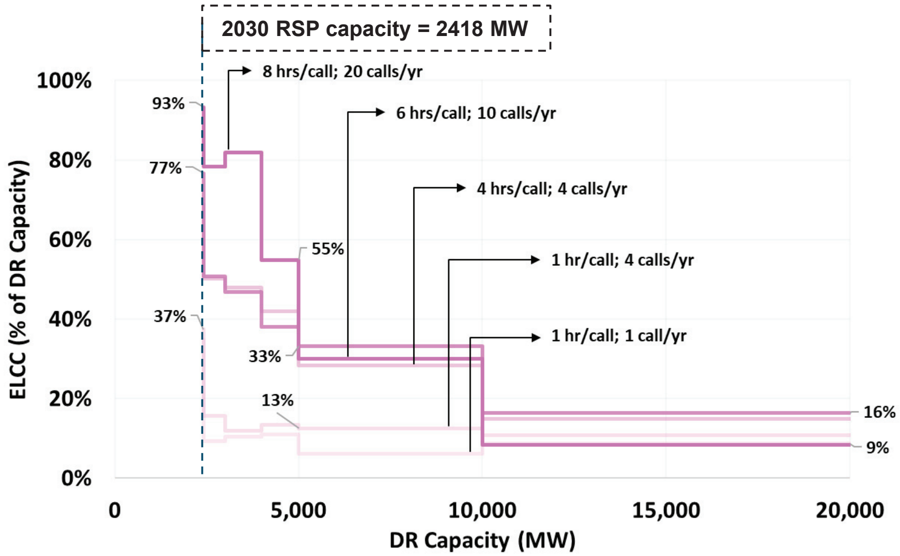
- **Average ELCC = Total Effective Capacity / Total Installed Capacity**
- **Incremental ELCC = ∆ Effective Capacity / ∆ Installed Capacity**
- **ELCC generally decreases as DR capacity on the system increases:**
  - Similarity in hours of operation and characteristics limits the incremental value that more of the exact same resource type can add to the system.
  - Degradation gets more severe as call constraints become more stringent.

DR ELCC Performance at Increasing Penetrations (2030)

Average Last-in ELCC



Incremental Last-in ELCC



+ **ELCC generally decreases as DR capacity on the system increases:**
  - Similarity in hours of operation and characteristics limits the incremental value that more of the exact same resource type can add to the system.
  - For a given DR capacity on the system, ELCC in 2030 is lower than that in 2019 owing to saturation of energy-limited resources on the system in 2030, particularly storage.

CPUC Role in RA & ELCC Implementation

+ **The CPUC has been a leader in North America through the incorporation of intermittent and energy-limited resources into RA frameworks**
  - One of the first to adopt and implement **ELCC** framework to value wind and solar
  - Currently the only jurisdiction that recognizes and accounts for **interactive effects** of resources through allocation of a "diversity benefit" to wind and solar
+ **The CPUC has recognized that the concept of "interactive effects" applies not only to renewables but to storage and other resources, but has not yet established an approach for allocation that incorporates them all**

R.17-09-020 ALJ/PVA/eg3

Steps 5 and 6 - Different Diversity Allocations

The tables below show results from allocating storage diversity to wind or solar resources

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
R. 14-10-010 Previously Adopted Values	Wind	11%	17%	18%	31%	31%	48%	30%	27%	27%	9%	8%	15%
CPUC proposed values - Diversity to Solar	Wind	14%	12%	28%	25%	25%	33%	23%	21%	15%	8%	12%	13%
Split storage diversity btwn wind/solar	Wind	13%	11%	31%	30%	28%	33%	22%	20%	15%	8%	11%	13%
Allocate storage diversity to wind	Wind	13%	9%	35%	36%	31%	34%	22%	20%	15%	7%	11%	12%

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
R. 14-10-010 Previously Adopted Values	Solar	0%	2%	10%	33%	31%	45%	42%	41%	33%	29%	4%	0%
CPUC proposed values - Diversity to Solar	Solar	4%	3%	18%	15%	16%	31%	39%	27%	14%	2%	2%	0%
Split storage diversity btwn wind/solar	Solar	5%	4%	16%	12%	15%	31%	39%	28%	14%	2%	2%	1%
Allocate storage diversity to wind	Solar	5%	5%	13%	8%	12%	30%	39%	29%	14%	3%	3%	1%

+ **Establishing a more generalized, durable framework for ELCC (capable of accounting for renewables, storage, and DR) will require a reexamination of the methods used to allocate ELCC and the "diversity benefit"**
+ **This section examines alternative options for allocating ELCC among resources that could improve upon existing methods currently in use**

Allocating ELCC

+ **Allocating Portfolio ELCC is necessary with a centralized or bilateral capacity market framework where individual resources must be assigned a capacity contribution for compensation purposes**
  - Directly impacts billions of dollars of market clearing transactions within California and other organized capacity markets
+ **Allocating Portfolio ELCC can impact planning and procurement in California to the extent that entities procure based on the economic signal they receive in the RA program**
  - An allocation exercise is not necessary in vertically integrated jurisdictions or in systems with a centralized procurement process
+ **There are an infinite number of methods to allocate Portfolio ELCC to individual resources and no single correct or scientific method, similar to rate design**

Sample ELCC Allocation Method Options

1. **Allocate proportionally to First-In ELCC**
2. **Allocate proportionally to Last-In ELCC**
3. **Allocate adjustment to First-In ELCC proportionally to differences between First-in and Last-In ELCC**
4. **Vintaging approach where each resource permanently receives Last-In ELCC at the time it was constructed**
5. **More**

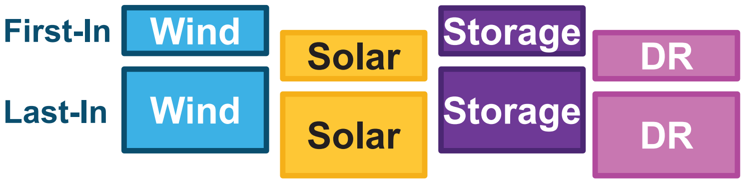
Framework to Incorporate DR ELCC Into CPUC RA Framework

+ **This section presents a framework as one option for attributing capacity value to DR *<u>within the current resource adequacy framework</u>* administered by the CPUC**
+ **This framework relies on several key principles:**
  1) **Reliability:** The ELCC allocated to each project/program should sum to the portfolio ELCC for all resources
  2) **Fairness:** ELCC calculations should be technology neutral, properly reward resources for the capacity characteristics they provide, and not unduly differentiate among similar resources
  3) **Efficiency:** ELCC values should send accurate signals to encourage an economically efficient outcome to maximize societal resources
  4) **Customer Acceptability:** ELCC calculations should be transparent, tractable understandable, and implementable

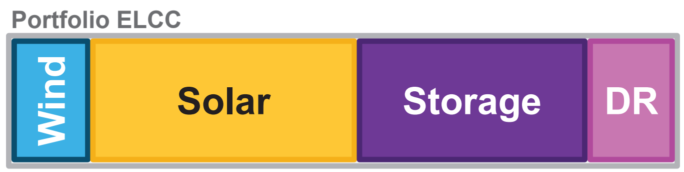
Overview of Framework

1. Calculate portfolio ELCC

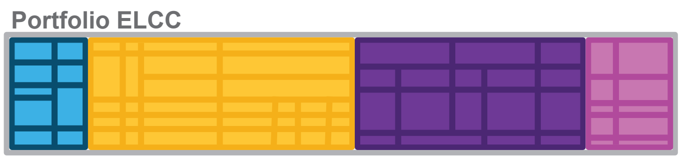
2. Calculate "first-in" and "last-in" ELCC for each resource category



3. Allocate portfolio ELCC to each resource category

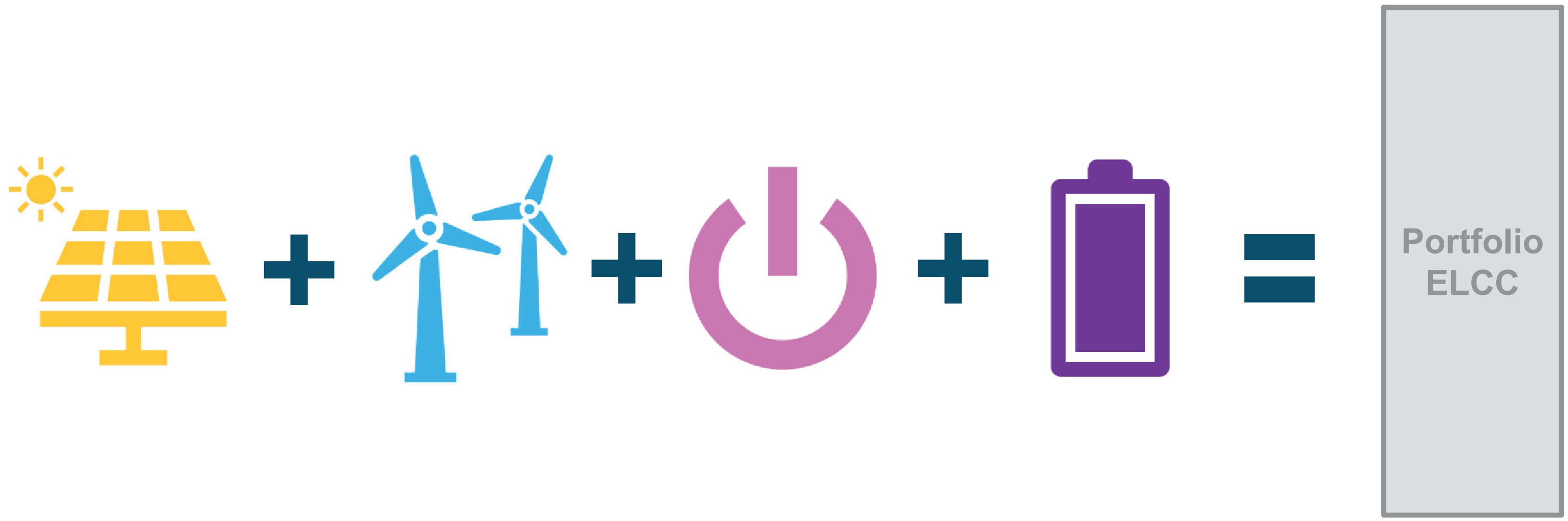


4. Allocate resource category ELCC to each project/program using tractable heuristic



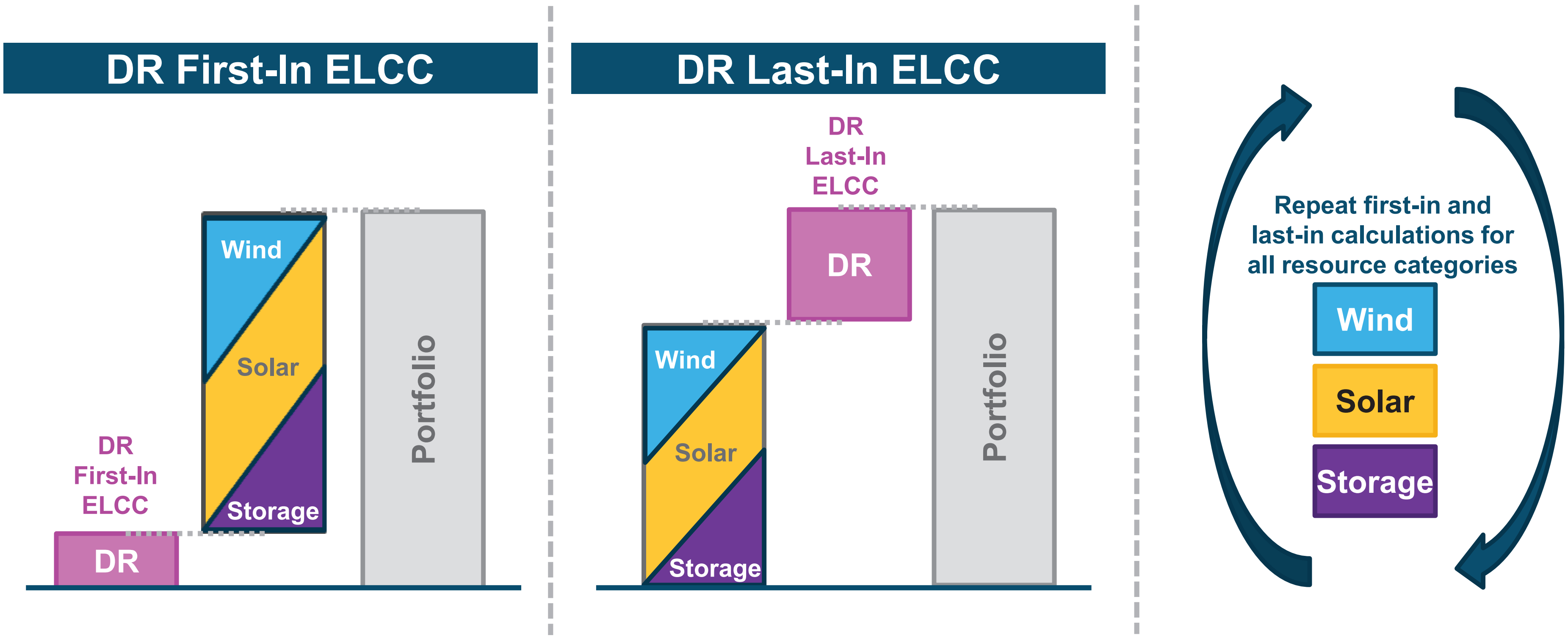
1) Calculate Portfolio ELCC

+ **The first step should calculate the portfolio ELCC of all variable and energy-limited resources**
  - Wind
  - Solar
  - Storage
  - Demand Response



2) Calculation First-In and Last-In Resource Category ELCCs

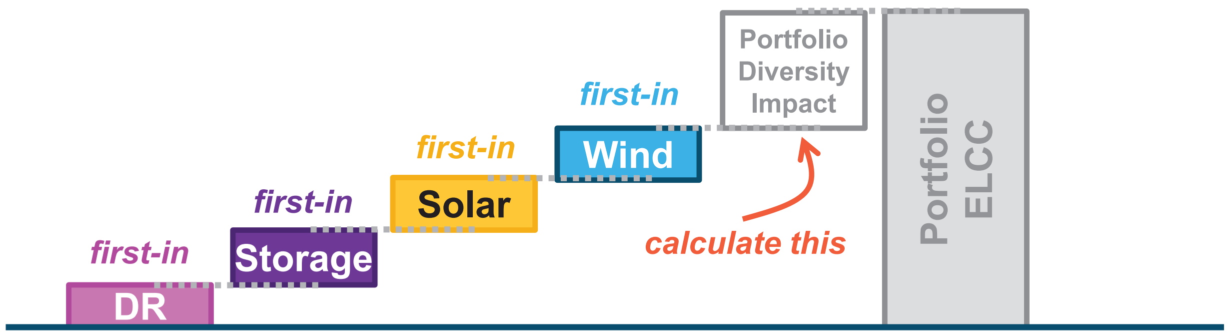
+ **The second step calculates the "first-in" and "last-in" ELCC for each resource category as a necessary input for allocation of the portfolio ELCC**



3) Allocate Portfolio ELCC to Each Resource Category

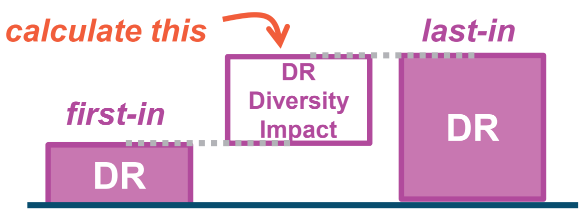
Calculate diversity impact as the difference between portfolio ELCC and sum of first-in ELCCs

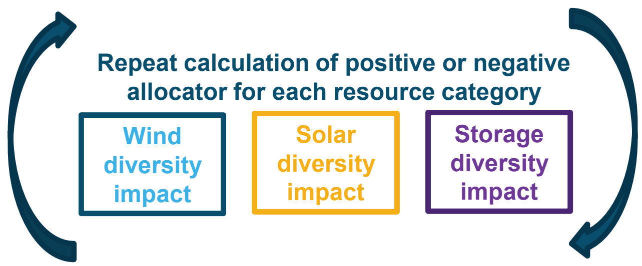
1



Calculate diversity impact for each resource category

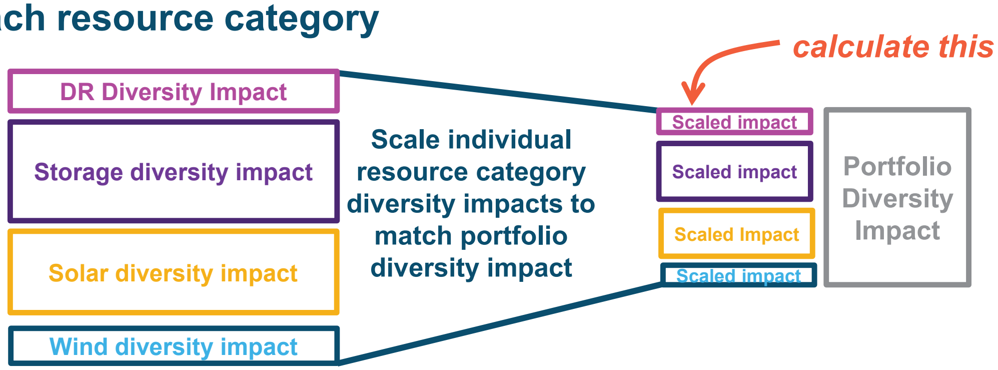
2

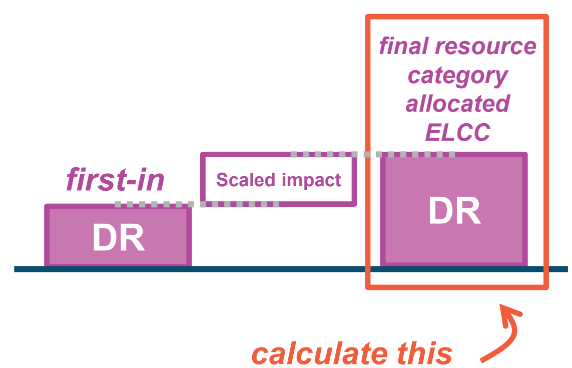




Allocate diversity impact in proportion to the difference between first-in and last-in ELCC for each resource category

3

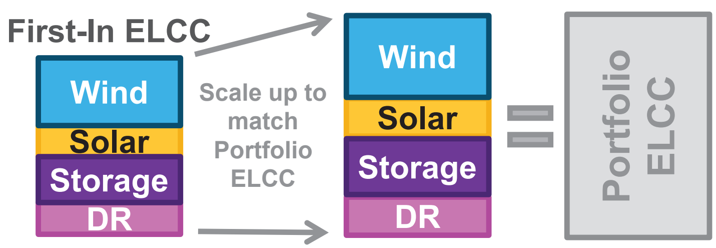


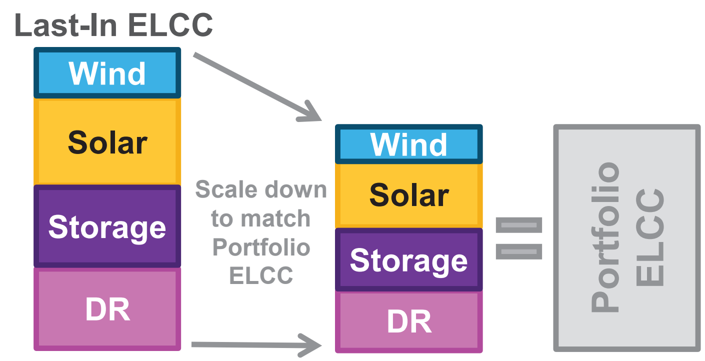


Benefits of this Approach

+ There are several options to allocate Portfolio ELCC to each technology category, two examples of which are shown below

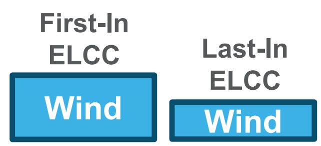
First-In ELCC Allocation Option	Last-In ELCC Allocation Option





+ Both of these options can lead to final ELCC allocations that fall outside the bounds of the first-in or last-in ELCC
  - For example, in the case of a "perfect" resource (e.g. ultra-long duration storage, always available DR, baseload renewables, etc.), this should be counted at 100% ELCC and should not be unduly scaled up or down based on the synergistic or antagonistic impacts of other resource interactions
  - Scaling the first-in or last-in ELCC in any way would result in an ELCC of either >100% or <100% for this perfect resource

+ The method presented in this deck scales resources based on the difference of their first-in and last-in ELCC in order to reflect their synergistic or antagonistic contributions to Portfolio ELCC



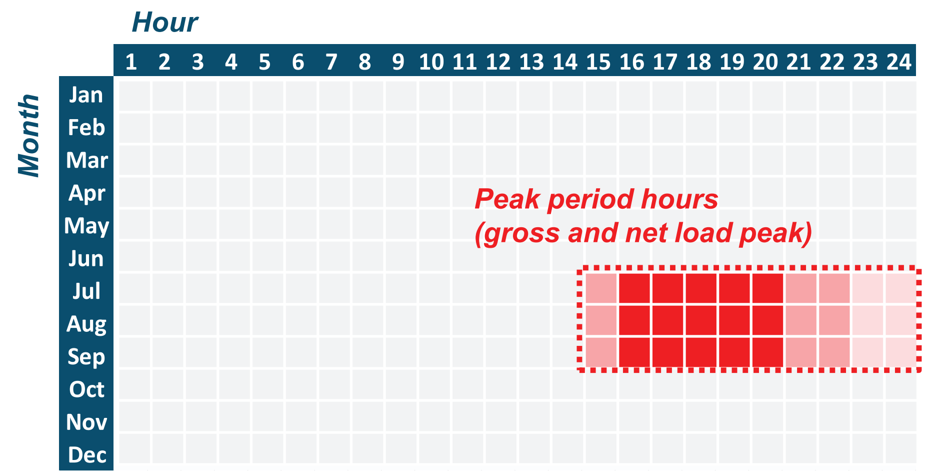
Negative diversity impact leads to first-in ELCC being scaled up to match Portfolio ELCC

Positive diversity impact leads to first-in ELCC being scaled down to match Portfolio ELCC

No diversity impact leads to no scaling of first-in ELCC to match Portfolio ELCC

4) Allocate Resource Category ELCC to Individual Resource/Programs Using Heuristics

- **Each DR program submits the following information**
  - Expected output during peak period hours
  - Maximum number of calls per year
  - Maximum duration of call
- **Step 1) Calculate average MW availability during peak period hours (gross and net load)**
- **Step 2) Multiple MW availability from step (1) by lookup table de-rating factor to account for call and duration limitations**
  - DR category ELCC to individual program ELCC using first-in and last-in ELCC would work similarly to the allocation process of portfolio ELCC to resource category ELCC



First-In ELCC

ELCC (% of nameplate)		Max annual calls						
		1	2	4	5	10	15	20
Max call duration (hrs)	1	41%	43%	43%	43%	43%	43%	43%
	2	60%	65%	65%	65%	65%	65%	65%
	4	72%	91%	95%	95%	95%	95%	95%
	6	73%	92%	98%	98%	98%	98%	98%
	8	73%	92%	98%	98%	98%	98%	98%

Last-In ELCC

ELCC (% of nameplate)		Max annual calls						
		1	2	4	5	10	15	20
Max call duration (hrs)	1	35%	37%	37%	37%	37%	37%	37%
	2	44%	49%	49%	49%	49%	49%	49%
	4	52%	65%	69%	69%	69%	69%	69%
	6	56%	77%	77%	77%	77%	77%	77%
	8	75%	91%	93%	93%	93%	93%	93%

Questions

Thank You

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Energy+Environmental Economics

Appendix

NQCs as a Basis for Comparison with ELCCs

- NQCs are calculated using load impacts (LI) , i.e. load reductions expected during peak conditions, calculated in line with the Load Impact Protocols.
- Load impacts are grossed up for transmission and distribution losses, as also the 15% PRM, owing to demand response being a demand reduction measure.

$$NQC = LI * 1.15\ (PRM) * T\&D\ loss\ factor$$ [1]

- Load impacts for the year 2019 are referenced from the CPUC's RA Compliance documents[2]
- Load impacts are defined on an LCA level from 1 pm to 6 pm, Apr to Oct, and from 4 pm to 9 pm in the rest of the year, both with and without line losses.

[1] CPUC 2019 RA Guide
[2] CPUC 2019 IoU DR Program Totals

Key Question: What Call and Duration Characteristics are Needed to Maximize DR ELCC?

+ E3 tested how two primary constraints impact the ELCC of demand response resources

- Max # of calls per year
  - How many times can a system operator dispatch a demand response resource?
- Max duration of each call
  - How long does the demand response resource respond when called by the system operator?

+ Key Assumptions:

- DR portfolio is divided into 100 MW units, each of which can be dispatched independently of the other
  - In other words, 2-hour-100 MW units can be dispatched in sequence to avoid an unserved energy event 100 MW deep and 4 hours long
- Each 100 MW unit is available 24/7, at full capacity of 100 MW, subject to call constraints defined above to establish a clear baseline for ELCC %'s
- Pure Shed DR; No shifting of load; No snap-backs

Average ELCC as a function of DR Capacity on the System

2019

First-in ELCC

ELCC (% of DR capacity) — Call constraints

DR capacity (MW)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	46%	51%	70%	94%	95%	95%	94%	95%
3,000	40%	47%	61%	92%	94%	96%	93%	96%
4,000	36%	42%	52%	78%	80%	86%	80%	86%
5,000	32%	39%	46%	73%	75%	83%	74%	84%
10,000	21%	30%	31%	51%	60%	65%	53%	70%
20,000	14%	21%	20%	33%	46%	44%	35%	52%

Last-in ELCC

ELCC (% of DR capacity) — Call constraints

DR capacity (MW)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	59%	73%	77%	100%	100%	100%	100%	100%
3,000	52%	65%	67%	99%	100%	100%	99%	100%
4,000	44%	57%	63%	93%	98%	98%	93%	98%
5,000	39%	52%	59%	87%	94%	94%	88%	94%
10,000	27%	39%	38%	61%	75%	75%	61%	80%
20,000	19%	28%	25%	39%	53%	50%	40%	57%

2030

First-in ELCC

ELCC (% of DR capacity) — Call constraints

DR capacity (MW)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	41%	43%	72%	95%	95%	98%	98%	98%
3,000	38%	40%	66%	92%	93%	98%	97%	98%
4,000	35%	37%	56%	83%	88%	91%	85%	91%
5,000	32%	35%	50%	74%	80%	86%	77%	88%
10,000	23%	30%	33%	52%	62%	67%	55%	71%
20,000	15%	22%	22%	35%	47%	46%	37%	53%

Last-in ELCC

ELCC (% of DR capacity) — Call constraints

DR capacity (MW)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	35%	37%	52%	69%	69%	77%	93%	93%
3,000	30%	33%	48%	65%	65%	72%	90%	90%
4,000	25%	28%	43%	61%	61%	65%	88%	88%
5,000	22%	25%	41%	57%	57%	60%	80%	82%
10,000	14%	19%	30%	43%	43%	47%	54%	56%
20,000	11%	15%	22%	29%	30%	31%	32%	32%

Incremental ELCC as a function of DR Capacity on the System

2019

First-in ELCC

Call constraints

DR capacity (MW) \ ELCC (% of DR capacity)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	46%	51%	70%	94%	95%	95%	94%	95%
3,000	25%	36%	37%	86%	93%	99%	90%	99%
4,000	22%	29%	26%	34%	39%	57%	40%	58%
5,000	15%	23%	22%	52%	56%	69%	51%	73%
10,000	11%	22%	16%	30%	45%	47%	32%	57%
20,000	7%	11%	10%	16%	31%	23%	17%	33%

Last-in ELCC

Call constraints

DR capacity (MW) \ ELCC (% of DR capacity)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	59%	73%	77%	100%	100%	100%	100%	100%
3,000	33%	42%	37%	96%	100%	100%	96%	100%
4,000	22%	34%	53%	77%	92%	92%	77%	92%
5,000	16%	31%	40%	62%	77%	78%	67%	78%
10,000	14%	26%	18%	35%	56%	56%	34%	66%
20,000	11%	18%	12%	18%	30%	25%	18%	34%

2030

First-in ELCC

Call constraints

DR capacity (MW) \ ELCC (% of DR capacity)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	41%	43%	72%	95%	95%	98%	98%	98%
3,000	26%	28%	42%	81%	84%	96%	94%	96%
4,000	25%	28%	25%	53%	71%	72%	48%	72%
5,000	19%	25%	24%	39%	48%	65%	45%	76%
10,000	15%	26%	17%	31%	45%	49%	33%	53%
20,000	8%	13%	11%	17%	32%	25%	19%	36%

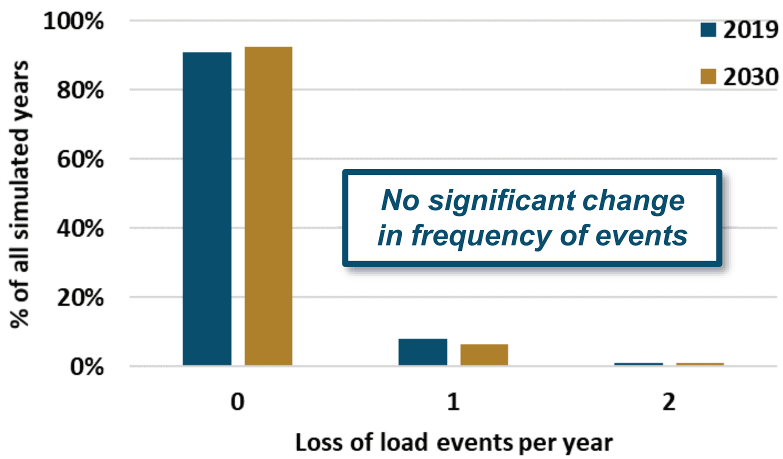
Last-in ELCC

Call constraints

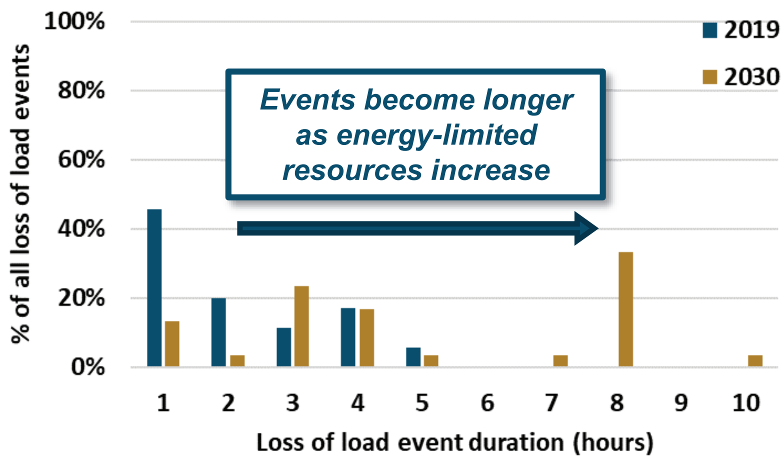
DR capacity (MW) \ ELCC (% of DR capacity)	1 hour/call 1 call/year	1 hour/call 4 calls/year	4 hours/call 1 call/year	4 hours/call 4 calls/year	4 hours/call 20 calls/year	6 hours/call 10 calls/year	8 hours/call 4 calls/year	8 hours/call 20 calls/year
2,195	35%	37%	52%	69%	69%	77%	93%	93%
3,000	9%	16%	29%	50%	50%	51%	78%	78%
4,000	10%	12%	29%	48%	48%	47%	82%	82%
5,000	11%	13%	34%	42%	42%	38%	46%	55%
10,000	6%	13%	20%	28%	28%	33%	29%	30%
20,000	9%	11%	13%	15%	18%	16%	9%	8%

2019 vs 2030 Loss of Load Events

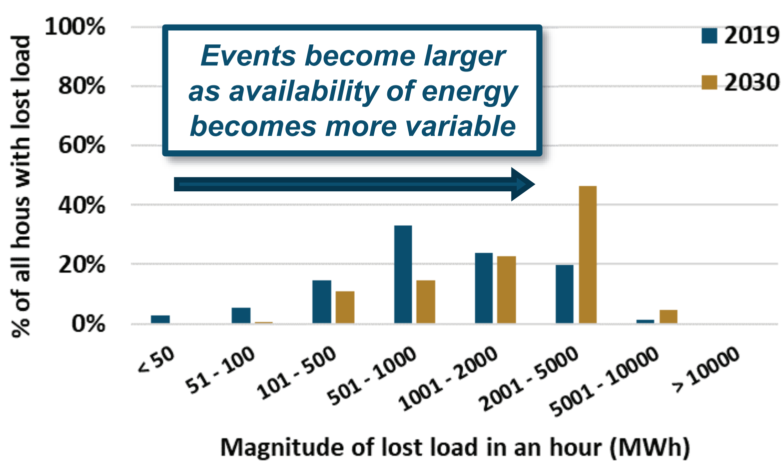
Frequency of Event Occurrence



Distribution of Event Duration



Distribution of Event Magnitude



Overview of Data

- **The 2019 PG&E and SCE DR ELCC results focus on "event-based" DR programs, as opposed to passive measures like dynamic pricing applicable throughout a season/year**
  - Does not consider SDG&E or Demand Response Auction Mechanism (DRAM) resources which are a significant portion of the data DR portfolio, due to data limitations
- **Data sources for RECAP ELCC calculations**
  1. Hourly PG&E DR bid data for 2019
     - BIP, CBP, and SAC
     - PSPS outage logs were provided by PG&E and used by E3 to identify and then fill gaps in DR bid data
  2. Hourly SCE DR bid data for 2019
     - API, BIP, CBP, and SDP

Data Benchmarking

+ **E3 used utility data directly from PG&E and SCE for two reasons**
  - CAISO does not have data by utility program
  - Wanted to ensure results were not predicated on CAISO data
+ **E3 benchmarked utility data to CAISO data to ensure the veracity of the data**
  - Data generally benchmarked well
  - A few inconsistencies were spotted in the RDRR data:
    - In ~1.3% of hours in the year, DR bids present in PG&E's data are missing in CAISO's data. Technical glitches in transmitting/recording systems may explain this.
    - DR bids in SCE data were slightly lower than bids recorded in CAISO data across significant portions of the year.

      Underlying reason is currently not known.

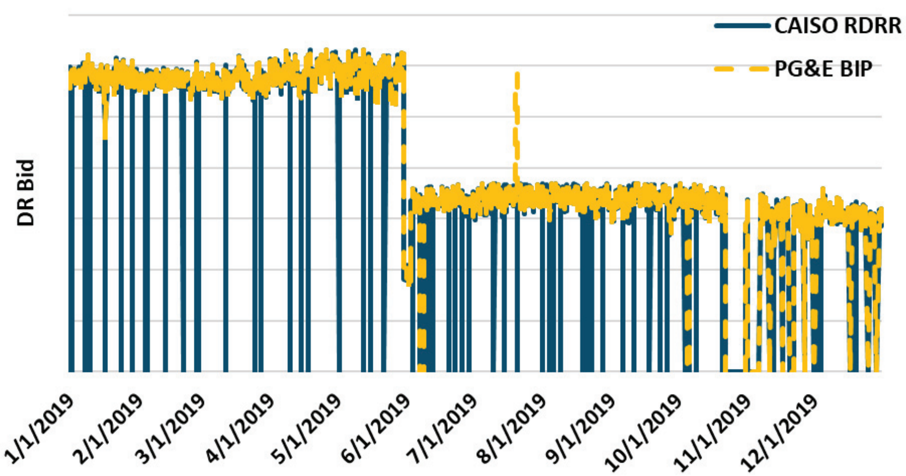
Benchmarking of 2019 Bid Data from PG&E and CAISO

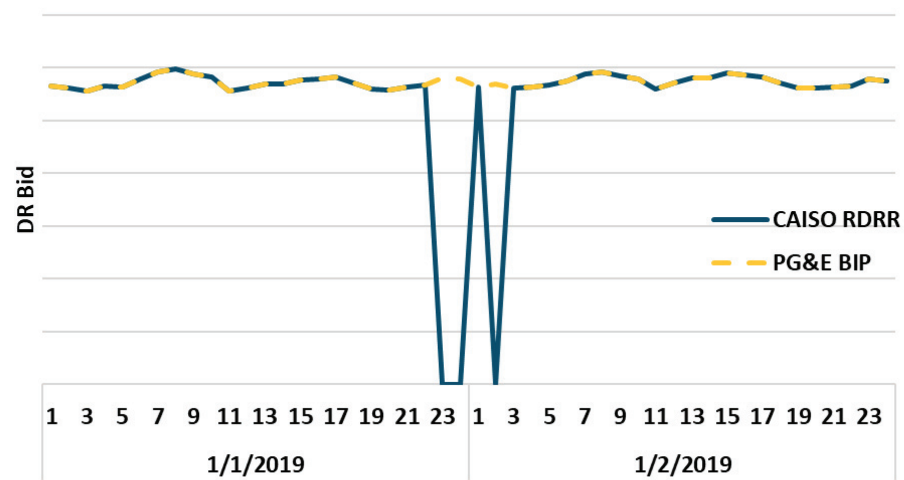
+ PDR data from the two sources are identical

+ There are a few hours (114 out of 8760) where RDRR data is inconsistent:

- Several instances across each of the 24 hours of the day
- These are hours where data is <u>missing</u> in the CAISO dataset
- Unclear if a bid was not placed, or if it was placed but not recorded due to technical glitches

Example comparison for one of the subLAPs over the entire year and a couple of days in specific

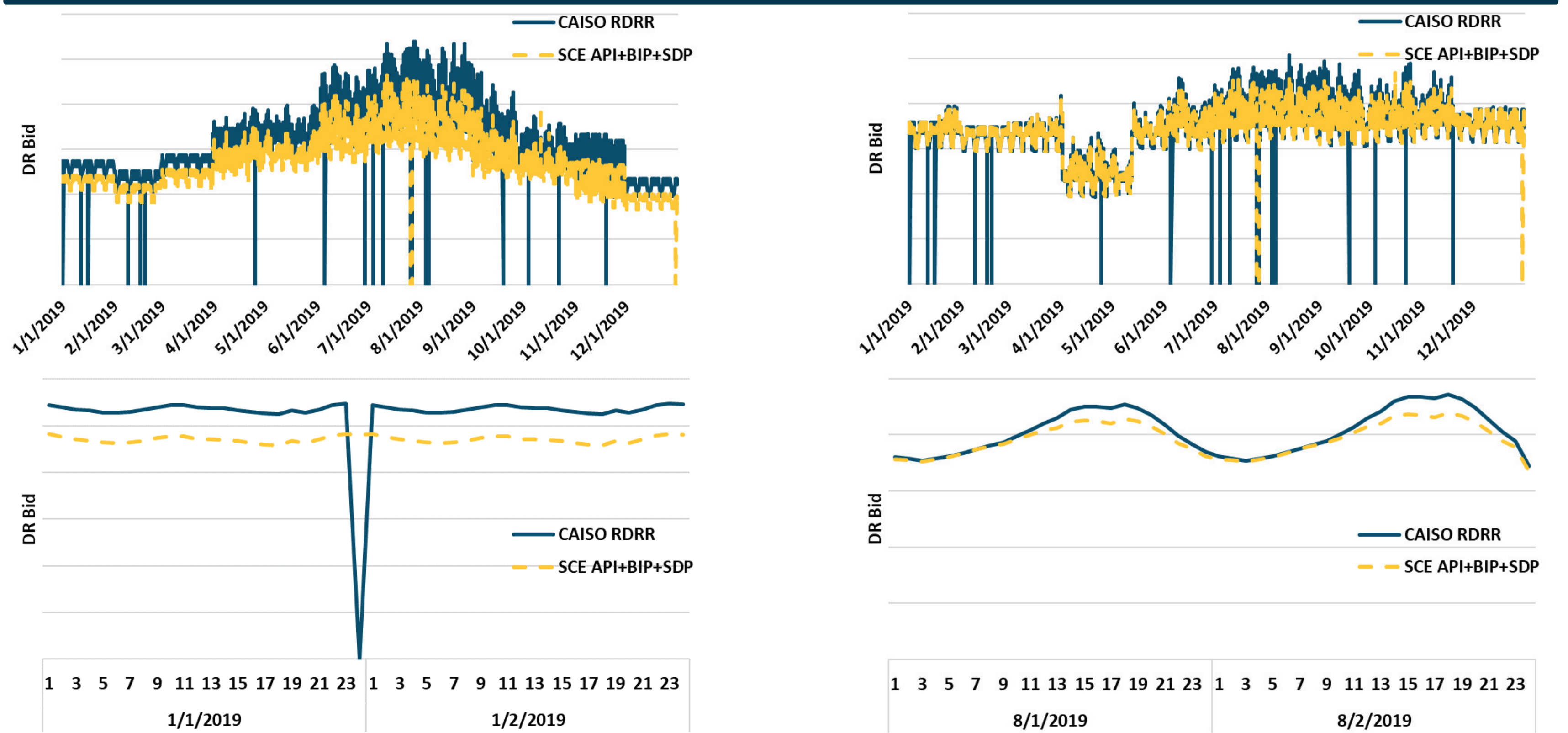




Benchmarking of 2019 Bid Data from SCE and CAISO data

- PDR data from the two sources are identical
- Inconsistencies exist in RDRR data – unclear if the difference is systematic and attributable to a single factor, like treatment of line-losses

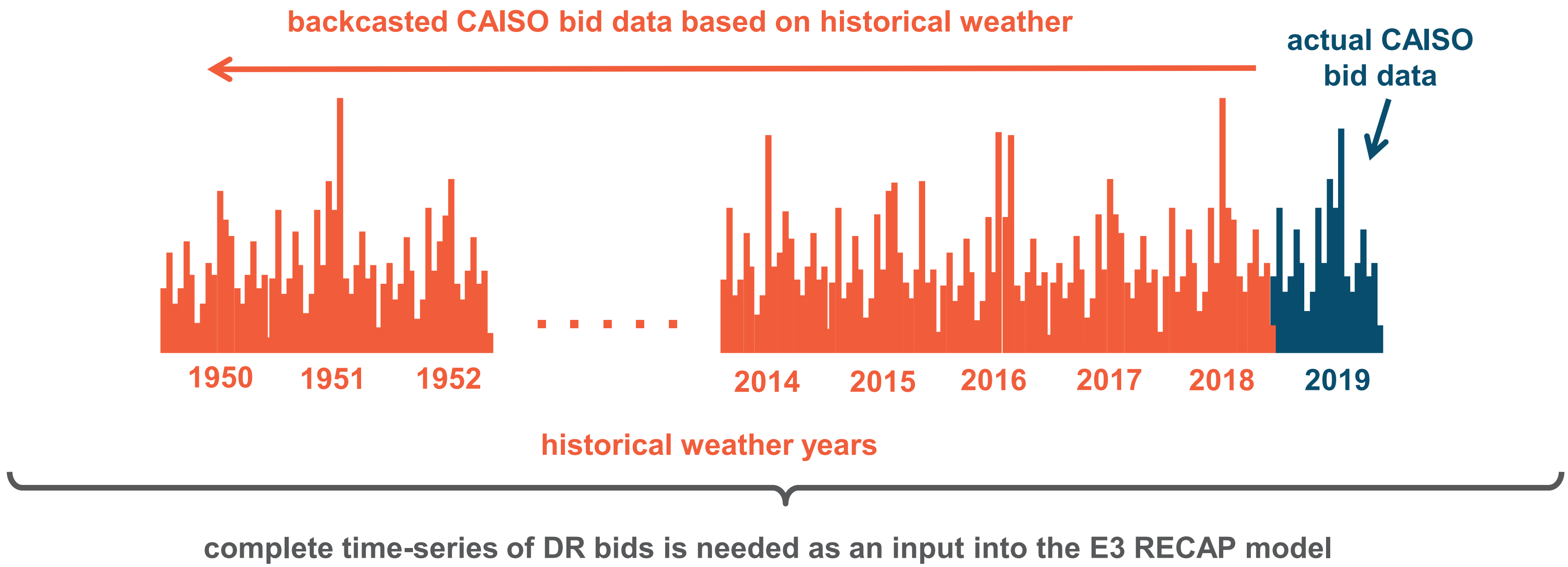
Example comparisons for 2 subLAPs- across the entire year and across a couple of days in specific



Extrapolation of DR Bid Data

+ In order to calculate the ELCC of a DR program or portfolio, RECAP must predict how these programs will perform over many different conditions and weather years

+ Therefore, E3 must extend actual 2019 data over the entire historical temperature record as a data requirement for the E3 RECAP model



+ In response to stakeholder feedback from the May 3 CAISO ESDER meeting, E3 modified the backcasting approach to include temperature for temperature-dependent air conditioner DR programs
  - More details on this process and methodology can be found in the appendix

Process of Extrapolating Actual DR Bid Data to Entire Weather Record

Get daily max, min and average temperature data (1950-2019) from NOAA for every climate zone that DR program bids come from

⇩

Use weather-informed day-matching to match every day from Jan 1, 1950 - Dec 31, 2018 to the "most similar" day from Jan 1, 2019 – Dec 31, 2019

⇩

Use day-matching results to extrapolate hourly DR bids from just 2019 to 1950-2019

⇩

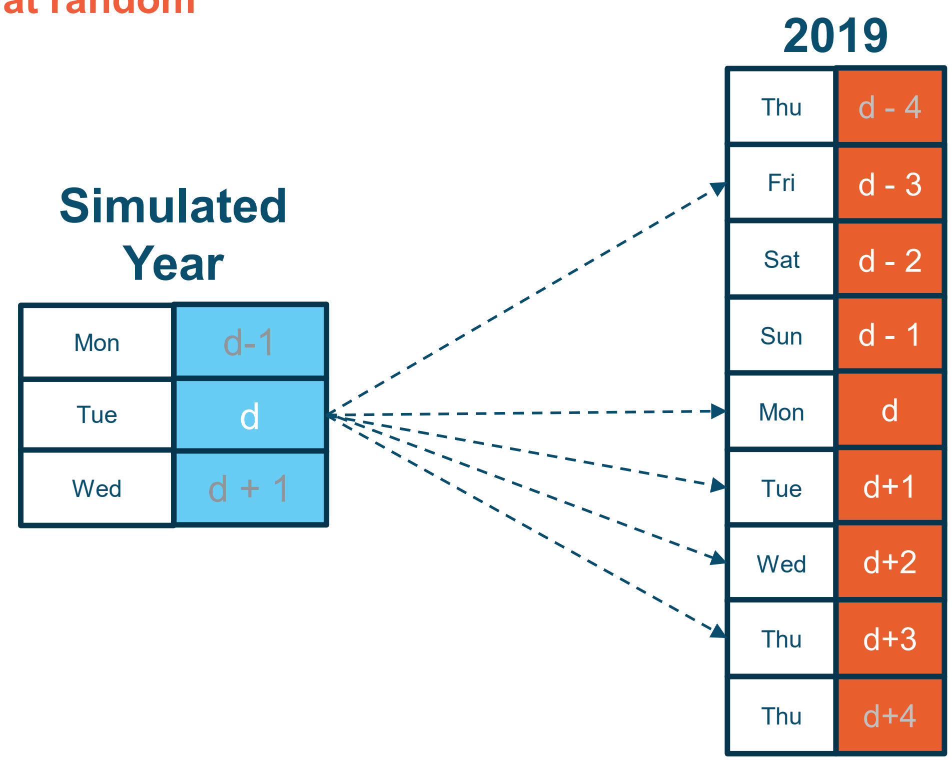
Aggregate extrapolated DR bids by program-LCA to allow for comparison with respective NQCs

⇩

Each aggregated shape dictates the hourly availability of the corresponding DR program-LCA combination in RECAP

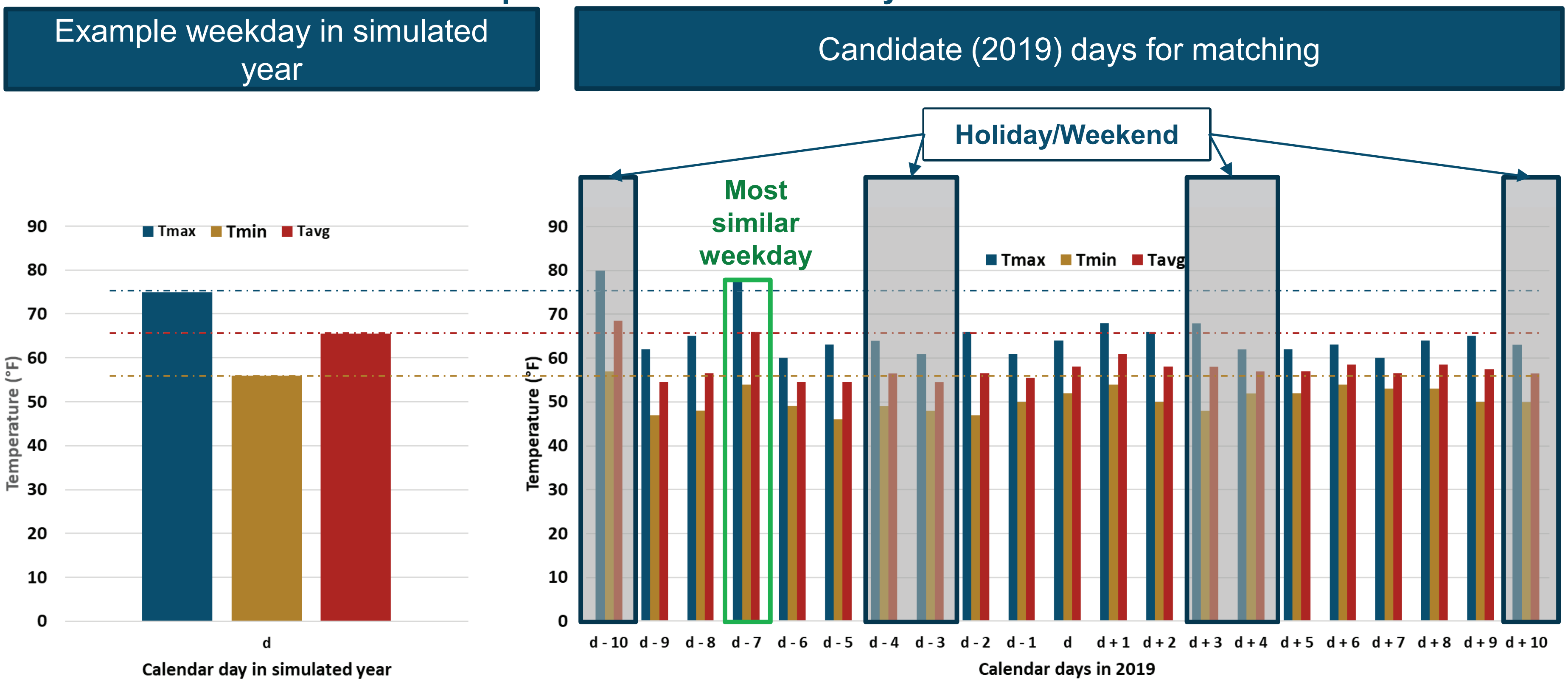
Simple Day-Matching Algorithm for CBP, BIP and API DR Programs

+ **As in the previous phase of this project, E3 used a simple day-matching approach for CBP, BIP and API programs**
+ **DR bid forecasts for these programs were not as strong a function of the temperature as Smart AC**
+ **For an individual DR program and a particular day, ‘d’ in a simulated year, pick one day out of +/- 3 calendar days, ‘d+3’ to ‘d-3’ of the same type (workday/holiday) from the actual 2019 data at random**



Weather-informed Day-Matching Algorithm for AC cycling DR Programs

+ Inclusion of weather for air conditioner DR is in direct feedback to stakeholder comments from the May 3, 2020 CAISO ESDER meeting
+ For an individual DR program and a particular day in a simulated year, pick one day out of +/- 10 calendar days of the same type (workday/holiday) from actual 2019 data **with the closest T_{max}, T_{min} and T_{avg}**
+ Applied to PG&E's Smart AC program and SCE's Summer Discount Plan program data to account for influence of temperature on DR availability

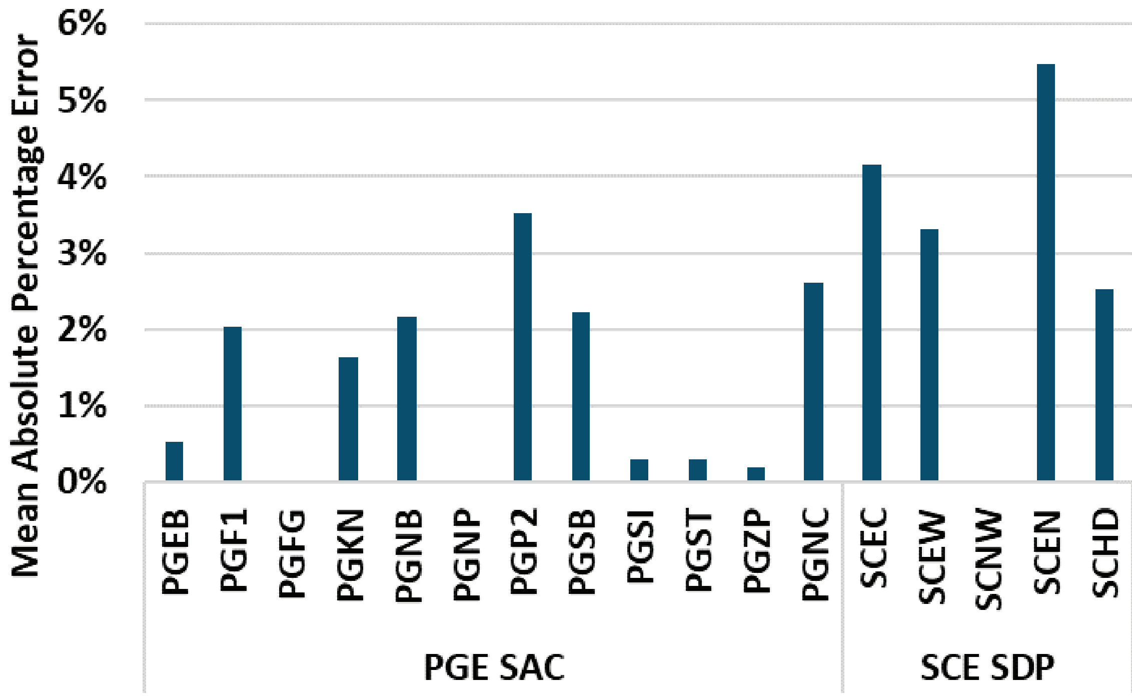


Comparison of day matched and real values

- The Mean Absolute Percentage Error (MAPE) is defined as:

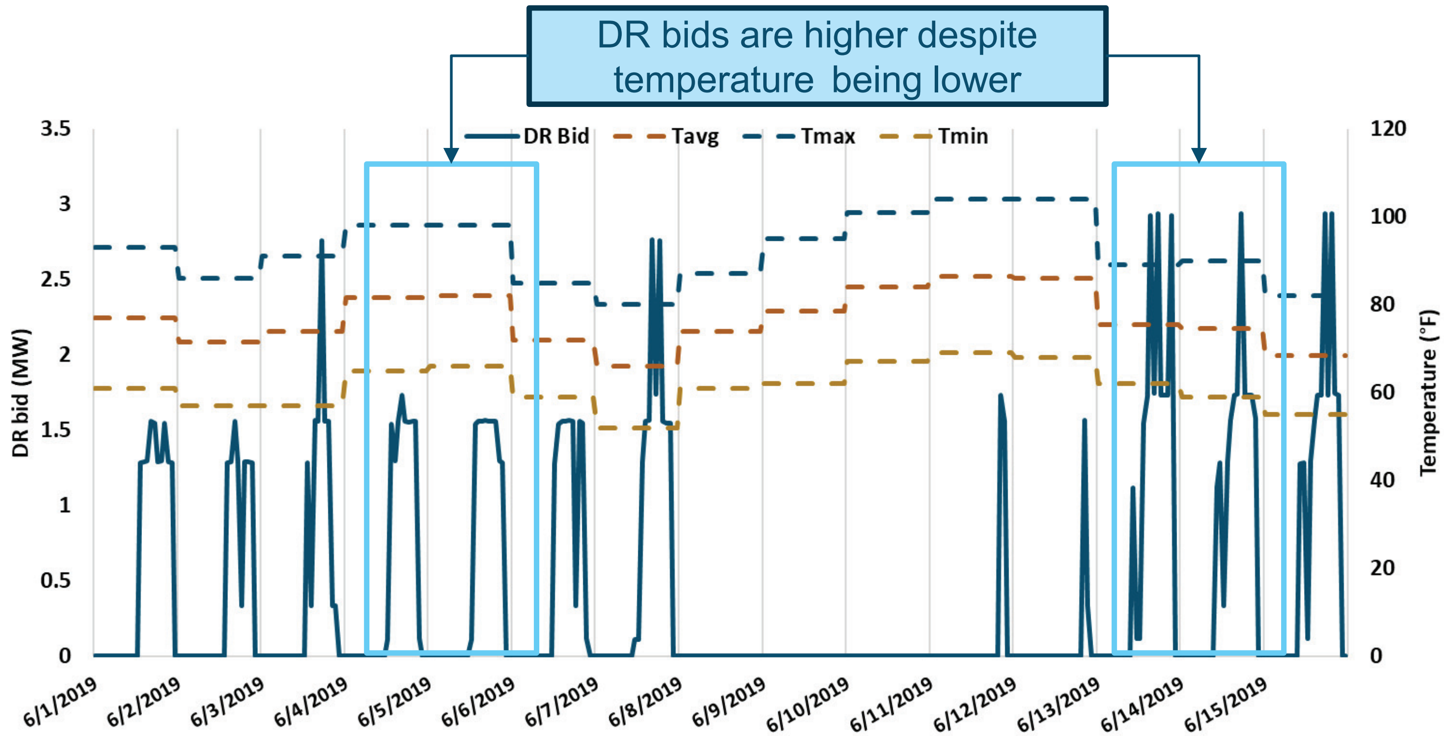
$$\frac{\text{Abs(Day–matched value – Actual Value) x 100}}{\text{Actual Value}}$$

- MAPE is calculated and shown below for July-September, 4 pm to 10 pm



Why Day Matching and not Regression?

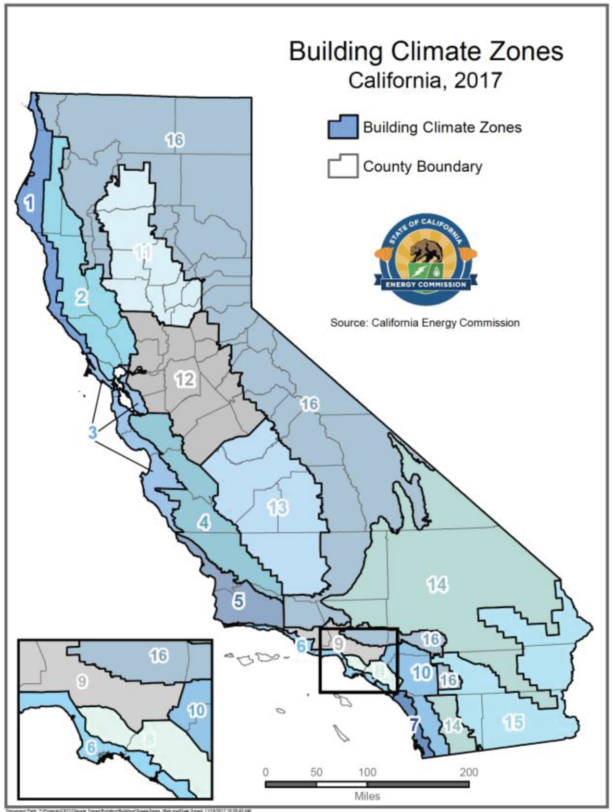
- **Regression based on temperature, month and day-type couldn't explain movement in DR bids. Potential reasons could be:**
  - Mismatch in temperature data used by E3 and IoUs.
  - Not accounting for other explanatory variables that IoUs use in their forecasts.
- **Absence of reliable hourly temperature records going back to 1950 meant only regression for daily DR bids was doable.**

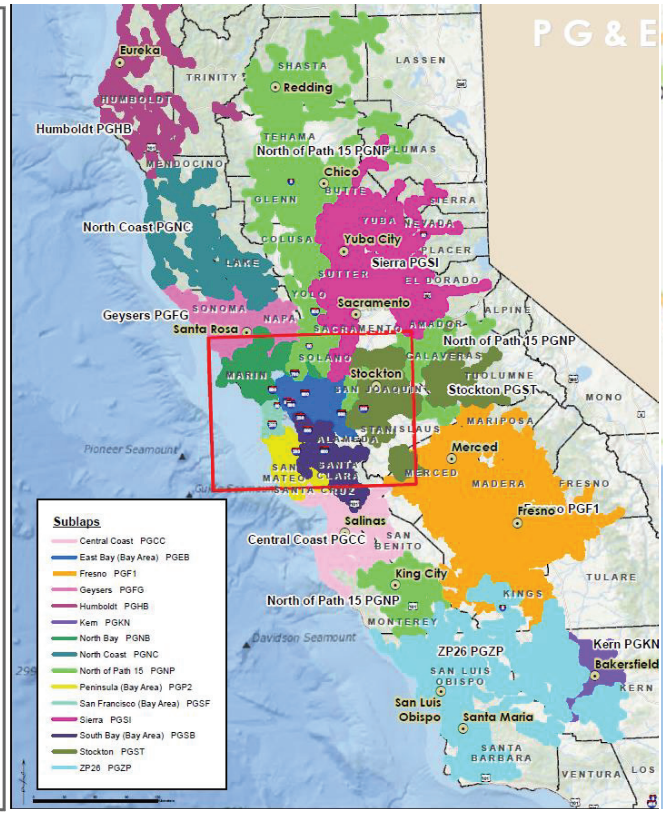


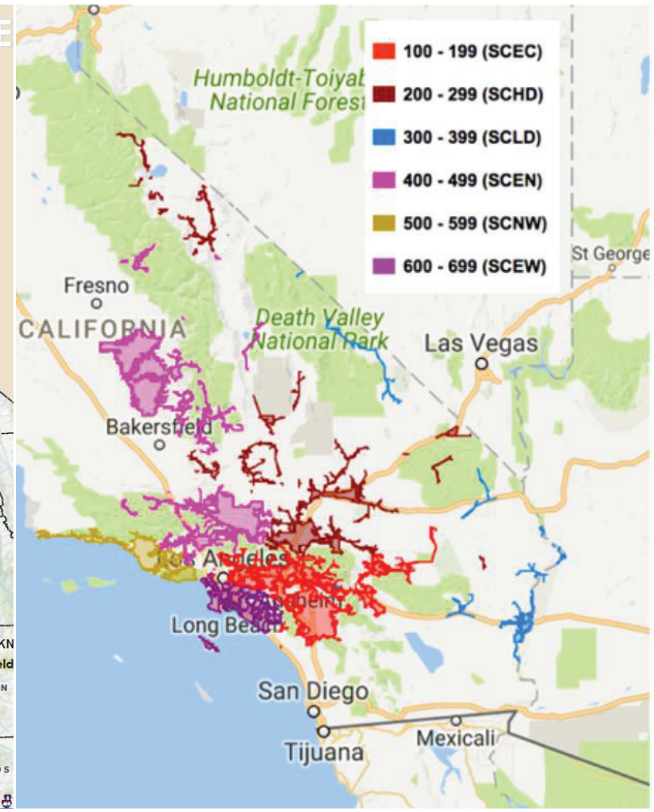
Assumptions on DR Program Characteristics

Utility	DR Program	Event Duration (hours/call)	Max. Events per Month	Max. Events per Year	Comments on RECAP Implementation
PG&E	BIP	6	10		
	CBP	6	5		30 hrs/month is interpreted as 5 events/month
	SAC	6		17	100 hrs/year is interpreted as 17 events/year
SCE	API	6	7		40 hours/month is interpreted as 7 events/month
	BIP	6	10		60 hours/month is interpreted as 10 calls/month
	CBP	6	5		30 hours/month is interpreted as 5 calls/month
	SDP	6		30	180 hours/year is interpreted as 30 events/year

Climate zones and sub-LAPs for reference







Sub-LAPs vs. Local Capacity Areas

Sub-LAP	Sub-LAP (long form)	Local Capacity Area
PGCC	PG&E Central Coast	Bay Area
PGEB	PG&E East Bay	Bay Area
PGF1	PG&E Fresno	Greater Fresno
PGFG	PG&E Fulton-Geysers	North Coast/North Bay
PGHB	PG&E Humboldt	Humboldt
PGKN	PG&E Kern	Kern
PGNB	PG&E North Bay	North Coast/North Bay
PGNC	PG&E North Coast	North Coast/North Bay
PGNP	PG&E North of Path 15 - non local	CAISO System
PGP2	PG&E Peninsula	Bay Area
PGSB	PG&E South Bay	Bay Area
PGSF	PG&E San Francisco	Bay Area
PGSI	PG&E Sierra	Sierra
PGST	PG&E Stockton	Stockton
PGZP	PG&E ZP26 (between Path 15 and 26) -non local	CAISO System
SCEC	SCE Central	LA Basin
SCEN	SCE North (Big Creek)	Big Creek/Ventura
SCEW	SCE West	LA Basin
SCHD	SCE High Desert	CAISO System
SCLD	SCE Low Desert	CAISO System
SCNW	SCE North-West (Ventura)	Big Creek/Ventura
SDG1	SDG&E	San Diego/Imperial Valley
VEA	VEA	CAISO System

Attachment B

2018 CAISO Testimony
Rulemaking 17-09-020

Track 2 Testimony
Corrected Chapter 6: Availability Limited Resources
July 10, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TRACK 2 TESTIMONY

CORRECTED CHAPTER 6: AVAILABILITY LIMITED RESOURCES

SPONSOR: John Goodin, Manager, Infrastructure and Regulatory Policy[1]

Nebiyu Yimer, Regional Transmission Engineer, Lead, Regional Transmission South[2]

Proposal No. 5: The Commission Should Recognize the Impact of Availability Limited Resources and Adopt the CAISO's Hourly Load and Resource Adequacy Analysis to Determine Availability Needs in Local Capacity Areas

I. The Commission Should Recognize the Impact of Availability-Limited Resources.

The California Independent System Operator Corporation (CAISO) defines availability-limited resources as those resources that have significant dispatch limitations such as limited duration hours (*e.g.*, per year, season, month, or day) or event calls (e.g., per year, season, month or consecutive days) that would limit the resources' ability to respond to a contingency event within a local capacity area. The CAISO's definition is limited to resources that count towards meeting a local capacity area or sub-area need. The CAISO strongly urges the Commission to adopt this definition.

[1] *See* John Goodin's statement of qualifications, attached hereto as Appendix A.
[2] *See* Nebiyu Yimer's statement of qualifications, attached hereto as Appendix B.

The resource adequacy program is currently based on meeting a peak capacity requirement defined in megawatts (MWs) without consideration of other resource availability needs. For example, under today's paradigm, a 10 MW/40 MWh resource has the same resource adequacy capacity value as a 10 MW/80 MWh resource. If a local capacity area requires 10 MW of capacity for an eight hour period during a contingency event, only the latter resource is capable of meeting this reliability need. Yet from a resource adequacy perspective, these hypothetical resources provide equivalent resource adequacy value because the resource adequacy program does not consider availability limitations. In recent years, the quantity of resources with some level of availability limitations, such as certain preferred and energy storage resources, has increased considerably. To continue this progression toward increasing levels of preferred and energy storage resources, the CAISO and the Commission must identify and account for availability limitations within local capacity areas and sub-areas to ensure that sufficient resources are procured to meet reliability requirements in all hours and during contingency situations.

II. The Commission Should Adopt the CAISO's Proposed Hourly Load and Resource Analysis to Determine Availability Needs in Local Capacity Areas.

In recent transmission planning studies, the CAISO demonstrated that simply satisfying the peak capacity needs in a local capacity area does not assure reliability consistent with the Local Capacity Technical Study criteria. Specifically, the CAISO's Moorpark Sub-Area Local Capacity Alternative Study and Supplemental Local Capacity Assessment for the Santa Clara Sub-Area (Moorpark and Santa Clara Studies) show that availability-limited resources with a four-hour minimum duration were insufficient, due to a lack of energy (*i.e.*, available MWh), to fully address the contingency events identified in the local capacity criteria.[3] In the Moorpark and Santa Clara Studies, the CAISO developed and performed detailed hourly load and resource analyses to determine whether there were binding availability limits in the local capacity sub-

[3] CAISO, Moorpark Sub-Area Local Capacity Alternative Study, August 16, 2017, https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf; and Santa Clara Sub-Area Local Capacity Technical Analysis, June 18, 2018, http://www.caiso.com/Documents/2023LocalCapacityTechnicalAnalysisfortheSantaClaraSub-Area.pdf.

area to better inform regulatory proceedings and specify more precisely the local capacity procurement needs in those areas. The CAISO proposes to conduct similar analysis to inform Commission's resource adequacy proceeding and corresponding load serving entity (LSE) or central buyer procurement efforts. The Commission should adopt the CAISO's hourly load and resource analysis to set local resource adequacy procurement requirements that are designed to meet both capacity and energy needs for each local area. If the Commission adopts this proposal, the CAISO plans to submit the results of its hourly load and resource analysis for each applicable local capacity area and sub-area in the Commission's 2019 resource adequacy proceeding (for the 2020 compliance year).

The CAISO notes that the Commission currently uses the CAISO's Local Capacity Technical Study as the basis for determining local resource adequacy capacity requirements. The CAISO conducts its local capacity technical study annually, and the Commission sets local capacity procurement obligations each year after reviewing the CAISO's recommendations. The Commission issues a decision requiring its LSEs procure a MW capacity amount; it does not expressly consider other needs, such as energy delivery or how availability limited resources satisfy these other critical needs in local capacity areas. The hourly load and resource analysis adds a layer of detail to the Local Capacity Technical Study that is necessary to ensure reliability as LSEs increasingly procure availability-limited resources to meet local capacity requirements. By adopting the CAISO's hourly load and resources analysis, the Commission will be taking important steps toward better informed LSE procurement in local capacity areas and minimizing the potential for CAISO backstop procurement.

III. The CAISO's Hourly Load and Resource Analysis Is Based on Existing Local Capacity Technical Study with Additional Steps to Ensure Energy Sufficiency.

The CAISO proposes to maintain the existing Local Capacity Technical Study process with certain changes described below, which will add detailed hourly load and resource analyses to determine the availability needs for each viable local capacity area and sub-area. The CAISO will continue to conduct its annual Local Capacity Technical Study to determine the local capacity requirements (in MW) for each local capacity area and sub-area, but the hourly load and resource analysis will provide additional critical information regarding availability needs in each local capacity area.[4] This analysis will require the additional inputs and study steps that are not included in the current Local Capacity Technical Study. The CAISO details these additional inputs and study steps below.

A. Additional Inputs for Hourly Load and Resource Analysis.

- **Projected hourly load data** for each local capacity area and sub-area, for each year of analysis under a multi-year resource adequacy framework. The projected load data should include the impact of BTM PV but exclude the impact of supply-side demand response resources. In prior analyses, the CAISO relied on data from either the California Energy Commission (CEC) or the participating transmission owners (PTOs). The CAISO is open to exploring additional sources. As a default, the CAISO suggests using CEC data, if available, followed by the PTOs as the data source.
- **Determine the voltage stability or thermal area load limit** for the critical contingency with variable and availability-limited resources excluded for each local capacity area and sub-area, for each year of analysis under a multi-year resource adequacy framework. In the determination of the load limit, CAISO will assume all conventional (non-availability-limited, non-variable) resources that have not announced to retire will be available throughout the multi-year resource adequacy horizon. The CAISO needs to conduct this additional assessment to determine the MW limit where non-availability-limited local resources will need to be dispatched to serve the local or sub-area load to avoid voltage collapse. Voltage collapse or thermal overloads for contingency events are typically the most limiting condition and often set the local area requirements.

[4] The CAISO's hourly load and resources analysis will maintain the same criteria and assumptions—such as the requirements to adhere to North American Electric Reliability Corporation (NERC) reliability standards, Western Electricity Coordinating Council (WECC) regional requirements, the CAISO transmission planning standards and the local capacity technical study criteria set out in the CAISO tariff. CAISO Tariff Section 40.3.1.1 provides that "[t]he Local Capacity Technical Study will determine the minimum amount of Local Capacity Area Resources needed to address the Contingencies identified in Section 40.3.1.2."

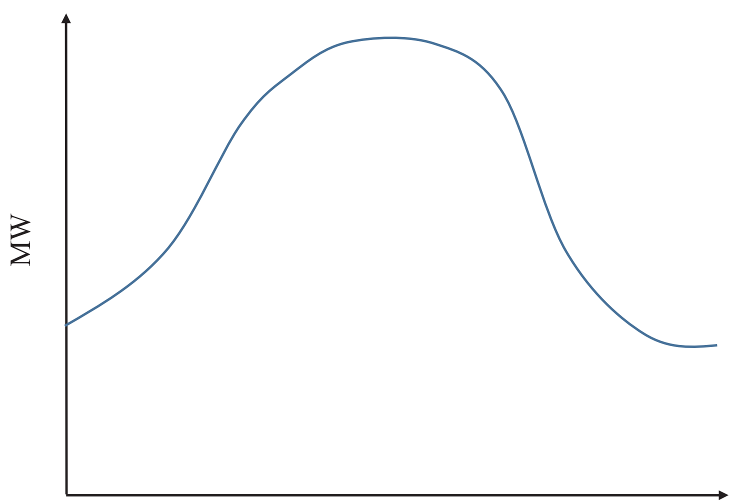
- **Hourly output data for supply side solar PV located in the area or sub-area** will also be needed to develop the net load shape.

B. Additional Study Steps for Hourly Load and Resource Analysis.

After receiving the additional inputs and using information available from the current Local Capacity Technical Study (such as existing and expected online resources in each local area and sub-area), a spreadsheet-based hourly load and resource analysis must be performed for each local capacity area and sub-area.[5] The figures below help to illustrate the steps the CAISO will take as part of the hourly load and resource analysis.

- **Determine the hourly load shape for each year of analysis under a multi-year resource adequacy framework.** Figure 1 below provides a graphical representation of the hourly load data that will be provided in the spreadsheet.

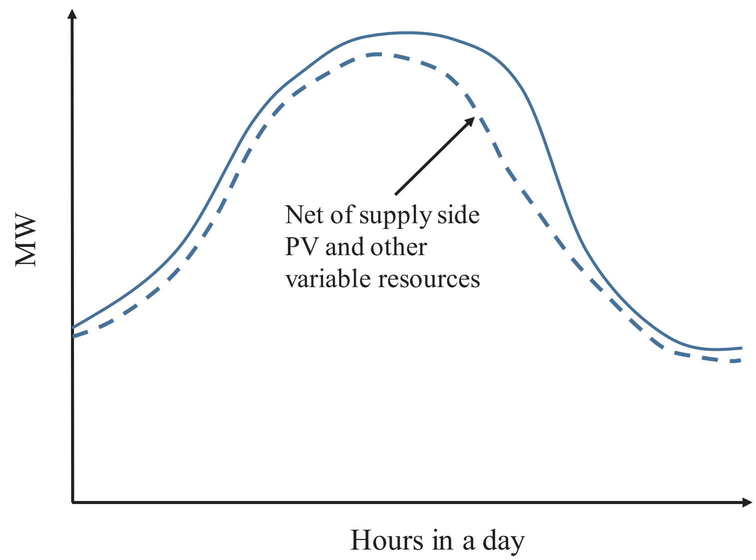
Figure 1: Illustrative Hourly Load Shape



- **Starting with the projected hourly load, subtract supply-side solar PV and other variable supply side resources not used in the derivation of the voltage-stability or thermal-load limit.** These resources are assumed to provide load reduction or generation largely based on their profiles. This net load is shown as the dotted blue line in Figure 2.

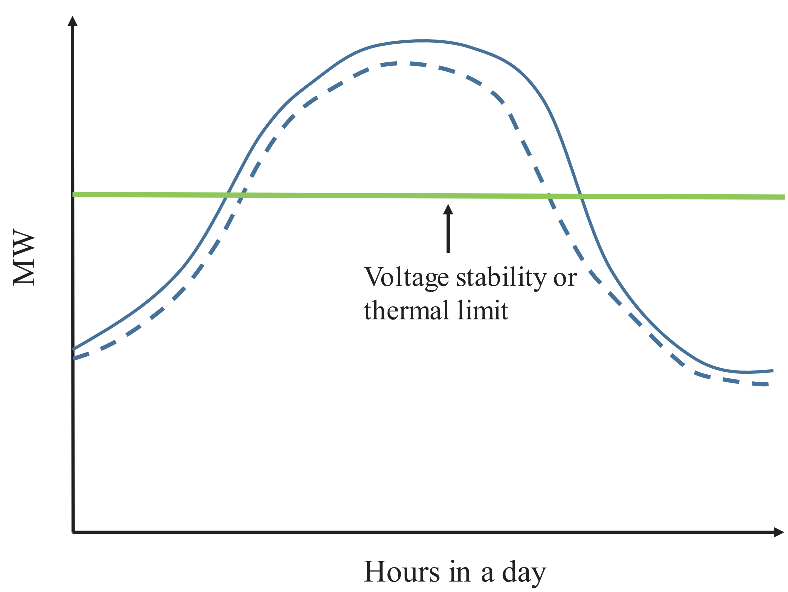
[5] *See* Moorpark Study, Appendix A – Hourly Load and Resource Analysis Worksheets.

Figure 2: Illustrative Hourly Load Shape Net of Supply Side Solar PV and Other Variable Resources



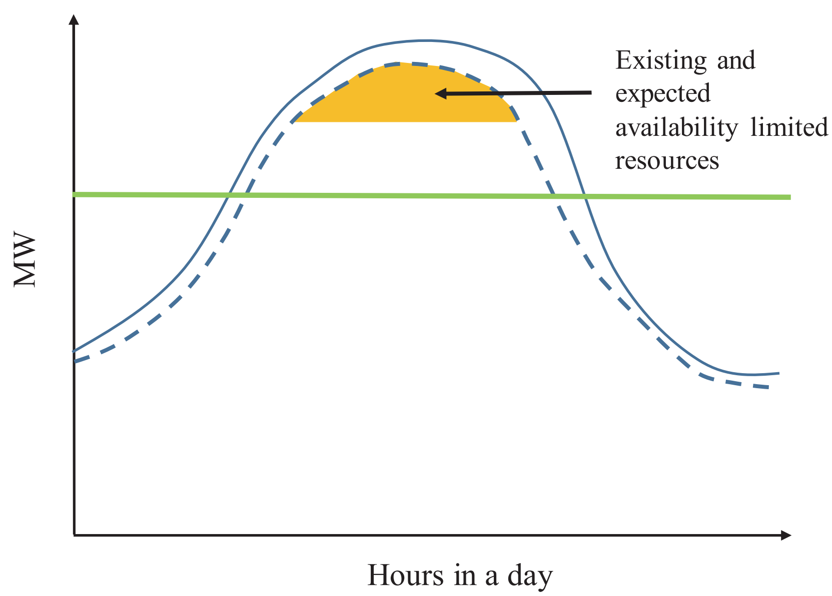
- **Subtract the voltage stability or thermal area load limit (input analysis) to derive the remaining load that may be served by availability-limited resources.** In Figure 3, this area is bounded by the voltage stability or thermal area load limit shown as a green horizontal line and the hourly load net of energy efficiency and solar PV shown as dotted blue line.

Figure 3: Voltage Stability or Thermal Area Load Limit



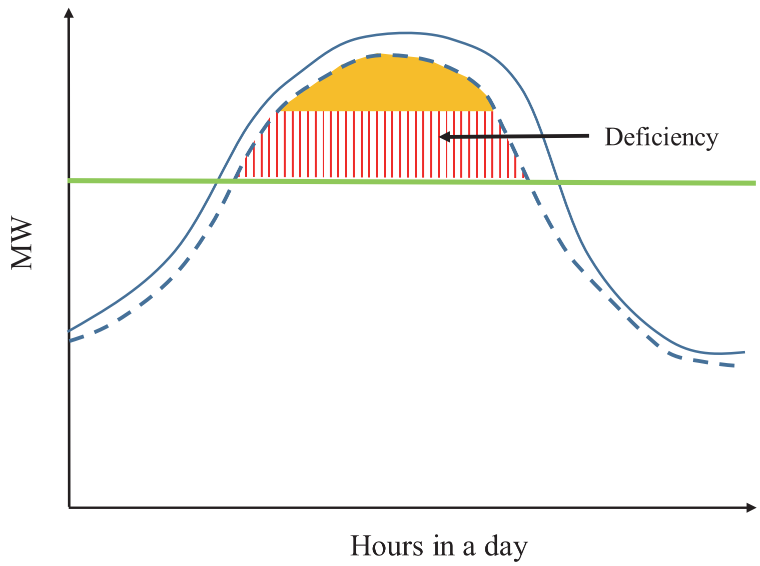
- **Assess whether existing and expected online availability-limited resources can meet the local capacity need.** This part of the assessment assumes availability-limited resources can serve the net load when the net load is greater than the voltage stability area load limit, recognizing all resources must be dispatched at the peak load hour and demand response is to be used last. The CAISO will use the resource parameters provided to the CAISO to appropriately model each resource's ability to meet the local area need such as number of calls or runtime for demand response programs or the need to recharge energy storage resources to be prepared for next day duty. Figure 4 below shows in yellow existing and expected online availability-limited resources' ability to serve load in this illustrative example.

Figure 4: Assessment of Availability Limited Resources



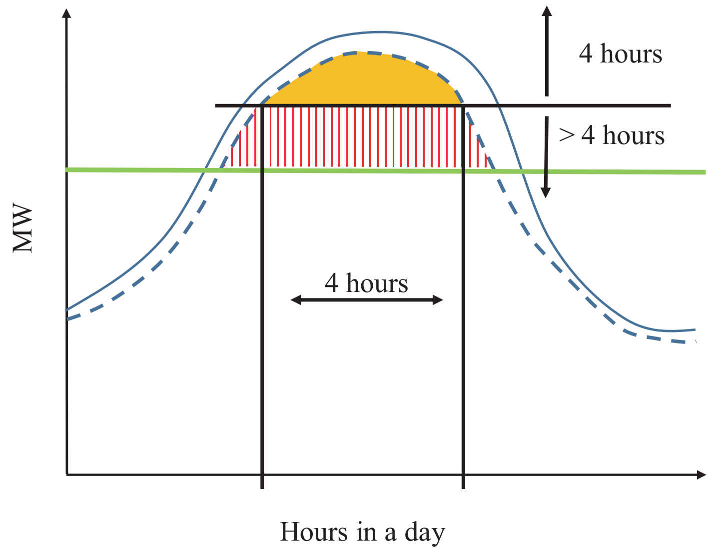
- **Identify any local area deficiencies.** Some local capacity areas or sub-areas may show a deficiency. If this is the case, the CAISO analysis will identify the deficiency on an hourly basis shown as the red striped area in Figure 5.

Figure 5: Identifying Local Area Deficiencies



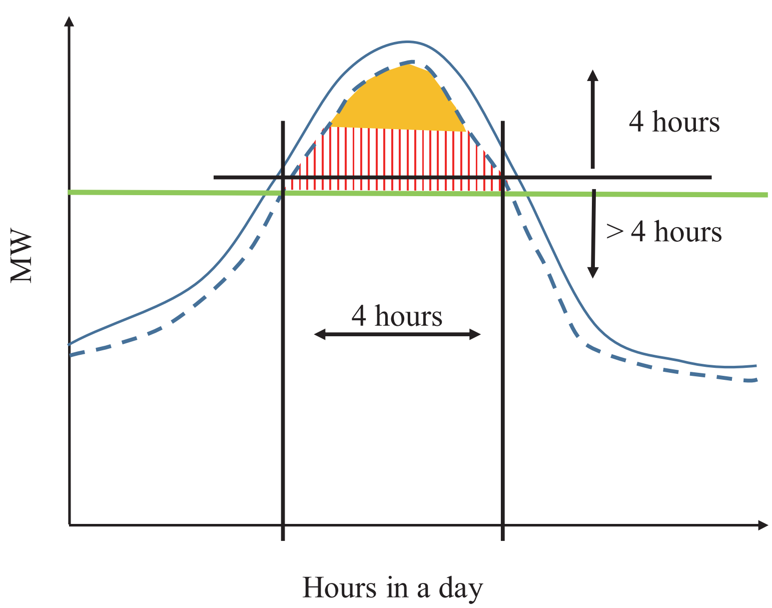
If there is a deficiency, CAISO's analysis will provide critical information to inform the additional procurement of availability-limited resources. The study assumes the Commission continues considering local and system resources as bundled for resource adequacy purposes, and the minimum availability requirement is four hours. In Figure 6 below, the solid vertical black lines reflect a four hour minimum availability threshold that includes the peak hour. Above the solid black horizontal line is the load that can be served with resources that meet this minimum availability. Below the solid black horizontal line is load that will need to be served with resources with greater than four hours of availability. In this example, the area below the line is the local area deficiency. Therefore, the deficiency can be met by both availability-limited and non-limited resources, but the duration of availability-limited resources must exceed four hours and specifically meet the needs of this local area.

Figure 6: Four Hour Minimum Availability Threshold



In comparison, Figure 7 shows another illustrative load profile with a much steeper and narrower peak period. This example shows that the minimum four hour availability threshold has not yet been reached so load serving entities wishing to procure more availability-limited resources can continue to rely on the minimum four-hour requirement up to the threshold. By providing the spreadsheet analysis, load serving entities will have a transparent and straightforward process to evaluate future procurement of necessary capacity.

Figure 7: Illustrative Alternative Load Shape



After load serving entities have followed this guidance, procurement will be validated against the availability needs as discussed in the next section.

IV. The Commission Should Adopt the CAISO's Proposed Process for Incorporating an Hourly Load and Resource Analysis into the Local Capacity Technical Analysis.

The CAISO's proposed hourly load and resource analysis to determine availability limitations requires significant new inputs and analyses. Below, the CAISO proposes a schedule for adopting and implementing the proposal to target implementation by the 2020 resource adequacy compliance year to align with multi-year resource adequacy procurement requirements. The CAISO's proposed implementation timeline is as follows:

Time	Activity
Q4 2018	• In Track 2 decision, Commission adopts CAISO's definition of availability-limited resources and hourly load and resource analysis.
Q1 2019	• Single forecast set is adopted by the CEC. Hourly load data may be available from the CEC or PTOs. • CAISO performs hourly load and resource analysis within the Local Capacity Technical Analysis stakeholder process
Q2 2019	• CAISO submits availability needs assessment into the Commission's resource adequacy proceeding as part of the Local Capacity Technical Analysis to guide resource procurement
Q4 2019	• Validate LSE procurement with power flow modeling

To leave enough time for the rest of the process, the CAISO requests the Commission adopt this proposal no later than in the fourth quarter of 2018. Shortly after, the CAISO must receive hourly load shapes for each local area and sub-area. A potential source for this data is the CEC's 10-year demand forecast adopted as part of its Integrated Energy Policy Report in the first quarter of 2019. The CAISO also expects to work collaboratively with its participating transmission owners to determine additional load or supply data, especially for local capacity sub-areas. The CAISO will evaluate several years of data to match the multi-year resource adequacy construct ultimately adopted by the Commission. During the rest of this quarter, the CAISO will perform the hourly load and resource analysis within its existing Local Capacity Technical Analysis stakeholder process.

In the second quarter of 2019, the CAISO expects to submit the results of the hourly load and resource analysis into the 2019 resource adequacy proceeding (for the 2020 compliance year) with the Local Capacity Technical Study. The hourly loads and resource analysis can then be used to guide local procurement for the 2020 compliance year.

In the fourth quarter of 2019, after load serving entities procure additional local capacity resources, the CAISO will validate the showings based on power flow modeling. This step is necessary because the spreadsheet load and resource analysis described in the preceding section does not consider reactive power and locational impacts. In this step, the CAISO models the load and resource dispatch for each hour of the 24-hour period obtained from the hourly load and resource analysis in the power flow model as needed to confirm that the dispatch yielded acceptable results. If the dispatch in any hour failed to yield acceptable results, the CAISO will use the existing process to allow load serving entities to cure any deficiencies.

In the first iteration of this process, the CAISO will analyze every local area and sub-area across the multi-year resource adequacy procurement horizon. In subsequent iterations, the CAISO may reduce the frequency and analysis of areas to those that show significant or increasing availability limitations, in order to manage CAISO's workload. Adopting the CAISO's study methodology will provide LSEs information to conduct procurement designed to meet the technical and operational characteristics the CAISO needs to ensure that local capacity requirements are fully met. In turn, this would reduce the need for CAISO backstop procurement.

Appendix A

Statement of Qualifications

John Goodin, Manager, Infrastructure and Regulatory Policy

Statement of Qualifications

John Goodin – Manager, Infrastructure and Regulatory Policy at the California ISO

Mr. Goodin has over 30 years' experience in the electric industry. In 1997, he was a part of the original start-up team for the California ISO (CAISO). Prior to joining the California ISO, Mr. Goodin worked at Pacific Gas & Electric Company for 10 years serving in various roles.

Mr. Goodin's current responsibilities at the California ISO include:

- Managing the Infrastructure and Regulatory Policy Team. This team is responsible for formulating the CAISO's market design and policies related to:
    - Resource adequacy and procurement
    - Transmission Infrastructure
    - Demand Response
    - Distributed Energy Resources

Mr. Goodin holds a Bachelor of Science in Mechanical Engineering from California Polytechnic State University, San Luis Obispo.

Appendix B

Statement of Qualifications

Nebiyu Yimer, Regional Transmission Engineer, Lead, Regional Transmission South

Statement of Qualifications

Nebiyu Yimer – Regional Transmission Engineer, Lead, Regional Transmission South at the California ISO.

Mr. Yimer has over 20 years of Transmission Planning experience in California, Canada and Ethiopia. Mr. Yimer is a licensed Professional Electrical Engineer in the province of Alberta, Canada.

Mr. Yimer's current responsibilities at the California ISO (CAISO) include:

- Planning the CAISO-controlled transmission system in southern California in the most cost effective manner and to ensure compliance with
    - North American Electric Reliability Corporation (NERC) reliability standards,
    - Western Electricity Coordinating Council (WECC) regional criteria, and
    - CAISO Transmission Planning Standards.
- Performed the CAISO local capacity requirements (LCR) technical analysis for the Moorpark sub-area for the 2017 local capacity technical study process.

Mr. Yimer holds a Master of Science in Renewable Energy from the University of Oldenburg, Germany and a Bachelor of Science in Electrical Engineering from Addis Ababa University, Ethiopia.

Attachment C

2021 Local Capacity Technical (LCT) Study

2021 Local Capacity Technical Study
Final Report & Study Results
May 1, 2020

2025 Local Capacity Technical Study
Final Report & Study Results
May 1, 2020

2021 LOCAL CAPACITY TECHNICAL STUDY

FINAL REPORT

AND STUDY RESULTS

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Executive Summary

This Report documents the results and recommendations of the 2021 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2021 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2019. On balance, the assumptions, and processes used for the 2021 LCT Study mirror those used in the 2007-2020 LCT Studies.

During 2019 the CAISO conducted a stakeholder process to update the LCR criteria to the current mandatory standards (NERC, WECC and CAISO) from its previous version that pre-dated any form of NERC mandatory standards.[1] CAISO held open stakeholder meetings on May 30, July 18 and September 10, 2019 resulting in overwhelming support for aligning the LCR criteria with the mandatory standards. The CAISO Board approved the alignment at its general session on November 13-14, 2019.[2] Tariff changes to implement the alignment were approved by FERC on January 17, 2020, with no opposition from any market participant.[3] The mandatory standards are closely aligned with old category C requirement as evident by the relatively small increase in overall local capacity requirements, 517 MW or 2.2%, between the 2020 and 2021 requirements. At the area and sub-area level results are mixed, while some areas and sub-areas have increased requirements others have a decreased requirement with many smaller sub-areas being eliminated.

The 2021 LCT study results are provided to the CPUC for consideration in its 2021 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).[4]

The load forecast used in this study is based on the final adopted California Energy Demand 2020-2030 Revised Forecast, developed by the CEC; namely the load-serving entity (LSE) and balancing authority (BA) mid baseline demand with low additional achievable energy efficiency and photo voltaic (AAEE-AAPV), posted on 3/4/2020: https://efiling.energy.ca.gov/GetDocument.aspx?tn=232305&DocumentContentId=64305.

To aide procurement, this LCT study provides load profiles and transmission capacity information that shows the effectiveness of local resources in meeting temporal local reliability needs.

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[1] See stakeholder webpage: http://www.caiso.com/StakeholderProcesses/Local-capacity-technical-study-criteria-update Stakeholder comments as well as CAISO responses are also linked on the webpage.

[2] See: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=A45DA998-F13E-4856-861D-0277E98D8E6E

[3] Available at: http://www.caiso.com/Documents/Jan17-2020-LetterOrderAcceptingTariffRevisions-UpdateLocalCapacityTechnicalStudyCriteria-ER20-548.pdf

[4] 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.

The studied results for 2021 are provided below and 2025 LCR needs are provided for comparison:

2021 Local Capacity Needs

	August Qualifying Capacity				Capacity Available at Peak	2021 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	191	0	191	191	130
North Coast/ North Bay	119	723	0	842	842	842*
Sierra	1183	920	5	2108	2103	1821*
Stockton	139	445	12	596	584	596*
Greater Bay	604	6806	8	7418	7418	6353
Greater Fresno	216	2815	361	3392	3191	1694*
Kern	5	330	78	413	335	413*
Big Creek/ Ventura	424	4454	250	5128	5128	2296
LA Basin	1197	8456	11	9664	9664	6127
San Diego/ Imperial Valley	2	4003	356	4361	4005	3888
Total	3889	29143	1081	34113	33461	24160

2025 Local Capacity Needs

	August Qualifying Capacity				Capacity Available at Peak	2025 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	191	0	191	191	132
North Coast/ North Bay	119	723	0	842	842	837
Sierra	1183	920	5	2108	2103	1367*
Stockton	116	491	12	619	607	619*
Greater Bay	604	6732	8	7344	7344	6110*
Greater Fresno	216	2815	361	3392	3191	1971*
Kern	5	330	78	413	335	186*
Big Creek/ Ventura	424	2963	250	3637	3637	1002
LA Basin	1197	6215	11	7423	7423	6309
San Diego/ Imperial Valley	2	4438	378	4818	4440	3557
Total	3866	25818	1103	30787	30113	22090

* Details about magnitude of deficiencies can be found in the applicable section below. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

The estimated results for years 2022 and 2023 LCR needs are provided below:

2022 Estimated Local Capacity Needs (No technical studies conducted)

	August Qualifying Capacity				Capacity Available at Peak	2022 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	191	0	191	191	131
North Coast/ North Bay	119	723	0	842	842	842
Sierra	1183	920	5	2108	2103	1834*
Stockton	139	445	12	596	584	596*
Greater Bay	604	6806	8	7418	7418	6292
Greater Fresno	216	2815	361	3392	3191	1763*
Kern	5	330	78	413	335	413*
Big Creek/ Ventura	424	4454	250	5128	5128	2291
LA Basin	1197	8456	11	9664	9664	6387
San Diego/ Imperial Valley	2	4088	348	4438	4090	3640
Total	3889	29228	1073	34190	33546	24189

2023 Estimated Local Capacity Needs (No technical studies conducted)

	August Qualifying Capacity				Capacity Available at Peak	2023 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	191	0	191	191	131
North Coast/ North Bay	119	723	0	842	842	840
Sierra	1183	920	5	2108	2103	1371*
Stockton	139	491	12	642	631	642*
Greater Bay	604	6732	8	7344	7344	6231
Greater Fresno	216	2815	361	3392	3191	1832*
Kern	5	330	78	413	335	300*
Big Creek/ Ventura	424	4454	250	5128	5128	1013
LA Basin	1197	8456	11	9664	9664	6361
San Diego/ Imperial Valley	2	4438	378	4818	4440	3481
Total	3889	29550	1103	34542	33869	22202

* Details about magnitude of deficiencies can be found in the applicable section below. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

The studied results for year 2020 LCR needs are provided below for comparison:

2020 Local Capacity Needs

	Qualifying Capacity				Capacity Available at Peak	2020 LCR Need Category B	2020 LCR Need Category C
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed	Capacity Needed
Humboldt	0	197	0	197	197	83	130
North Coast/ North Bay	117	715	1	833	832	742	742
Sierra	1168	986	6	2160	2154	1091	1764*
Stockton	155	497	1	653	652	603*	629*
Greater Bay	617	6438	12	7067	7067	3970	4550
Greater Fresno	203	2583	372	3158	2751	1694	1694*
Kern	8	354	103	465	362	169*	465*
Big Creek/ Ventura	402	4343	305	5050	5050	2154	2410*
LA Basin	1344	9078	17	10439	10104	7364	7364
San Diego/ Imperial Valley	4	3891	439	4334	3895	3895	3895
Total	4018	29082	1256	34356	33064	21765	23643

* Details about magnitude of deficiencies can be found in the applicable section below. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

Overall, the capacity needed for LCR has increased by about 517 MW or about 2.2% from 2020 to 2021.

The LCR needs have decreased in the following areas: Big Creek/Ventura and San Diego due to load forecast decrease, LA Basin due to new transmission projects, Stockton due to changes in the LCR criteria, Kern due to decrease in available Qualifying Capacity, Fresno and Humboldt requirement is the same.

The LCR needs have increased in the following areas: North Coast/North Bay due to change in the LCR criteria, Bay Area and Sierra due to load forecast increase and change in the LCR criteria.

The narrative for each Local Capacity Area lists important new projects included in the base cases as well as a description of the reason for changes between the 2020 and 2021 LCT study results.

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1. Overview of the Study: Inputs, Outputs and Options

1.1 Objectives

The intent of the 2021 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, as was the objective of all previous Local Capacity Technical Studies.

To aid procurement, this LCT study provides load profiles and transmission capacity information that shows the effectiveness of local resources in meeting temporal local reliability needs.

1.2 Key Study Assumptions

1.2.1 Inputs, Assumptions and Methodology

The inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2021 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2019. Except for Study Criteria all other Methodology and Assumptions are similar to those used and incorporated in previous LCT studies. The following table sets forth a summary of the approved inputs and methodology that have been used in this 2021 LCT Study:

Table 1.2-1 Summary Table of Inputs and Methodology Used in this LCT Study:

Issue	How 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 LCT Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
All Performance Levels, including incorporation of PTO operational solutions	This LCT Study is being published based on the most stringent of all mandatory reliability standards. 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 mandatory standards 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 2021 LCT Study methodology and assumptions are provided in Section III, below.

1.3 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.[5] 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.

1.4 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 (N-0) the CAISO must protect for all single contingencies (N-1) and common mode (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 temporal differentiation between two existing NERC Category P6 and P7 events. N-1-1 represents NERC Category C6 ("category P1 contingency, manual system adjustment, followed by another category P1 contingency"). The N-2 represents NERC Category P7 ("any two circuits of a multiple circuit tower line") as well as WECC-S2 (for 500 kV only) ("any two circuits in the same right-of-way") with no manual system adjustment between the two contingencies.

[5] Pub. Utilities Code § 345

1.5 Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCR Report is based on the most stringent mandatory standard (NERC, WECC or CAISO). The CAISO tests the electric system in regards to thermal overloads as well as dynamic and reactive margin compliance with the existing standards.

1.5.1 Performance Criteria

Category P0, P1 & P3 system performance requires that 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.

The NERC Planning 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.[6] All Category P2, P4, P5, P6, P7 and extreme event 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 planning criteria.

Generally, Category P2, P4, P5, P6, P7 and extreme event 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 P1, the event is effectively a Category P6 or N-1-1 scenario. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of

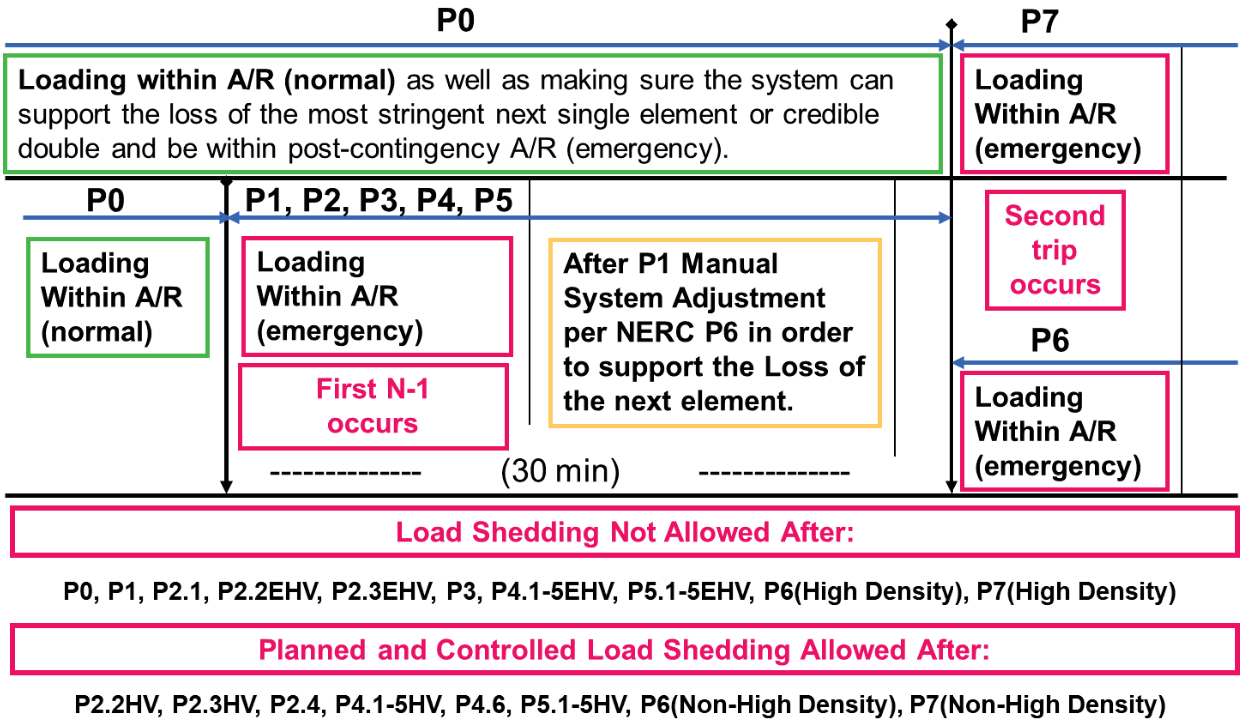
[6] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit 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 sometimes these systems will operate when not required and other times they will not operate when needed.

supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid “security.”

1.5.2 CAISO Statutory Obligation Regarding Safe Operation

The ISO must 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 (8760 hours per year), the ISO must protect for all single contingencies (P1, P2) and multiple contingencies (P4, P5) as well as common mode double line outages (P7). As a further example, after a single contingency, the ISO must readjust the system in order to be able to support the loss of the next most stringent contingency (P3 , P6 and P1+P7 resulting in potential voltage collapse or dynamic instability).

Figure 1.5-1 Temporal graph of LCR Category P0-P7



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

<u>Applicable Rating:</u>

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

<u>Normal rating</u> is to be used under normal conditions.

<u>Long-term emergency ratings</u>, 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, the 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, and 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 agreed 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 Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

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 ISO Grid Planning standards (ISO SPS3)

b. Increase generation – this generation will become part of the LCR need

Actions, which shall not be taken as system readjustment after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

1. Load drop – based on the intent of the ISO/WECC and NERC criteria for category P1 contingencies.

An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. NERC and ISO Planning standards mandate that no load shedding should be done immediately after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency. The system should be planned with no load shedding regardless of when it may occur (immediately or within 15-30 minutes after the first contingency). It follows that load shedding may not be utilized as part of the system readjustment period – in order to protect for the next most limiting contingency. Therefore, if there are available resources in the local area, such resources should be used during the manual adjustment period (and included in the LCR need) before resorting to shedding firm load.

Firm load shedding is allowed in a planned and controlled manner after the first contingency in P2.2(HV), P2.3(HV), P2.4, P4.1-5(HV), P4.6, P5.1-5(HV) and after the second contingency in P6(non-high density area), P7(non-high density area) & P1 system adjusted followed by P7 category events.

This interpretation tends to guarantee that firm load shedding is used to address Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) conditions only under the limited circumstances where no other resource or validated operational measure is available. A contrary interpretation would constitute a departure from existing practice and degrade current service expectations by increasing load's exposure to service interruptions.

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) having 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.

2. Assumption Details: How the Study was Conducted

2.1 System Planning Criteria

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

Table 2.1-1: Criteria Comparison for Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	New Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X[1]
2. Transmission Circuit (L-1)	X	X[1]	X[1]
3. Transformer (T-1)	X	X[1,2]	X[1]
4. Shunt Device	X		X[1]
5. Single Pole (dc) Line	X	X[1]	X[1]
P2 – Single contingency			
1. Opening a line section w/o a fault	X		X
2. Bus Section fault	X		X
3. Internal Breaker fault (non-Bus-tie Breaker)	X		X
4. Internal Breaker fault (Bus-tie Breaker)	X		X
P3 – Multiple Contingency – G-1 + system adjustment and:			
1. Generator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Transformer (T-1)	X	X[2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X	X
P4 – Multiple Contingency - Fault plus stuck breaker			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X
6. Bus-tie breaker	X		X
P5 – Multiple Contingency – Relay failure (delayed clearing)			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X

P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:			
1. Transmission Circuit (L-1)	X	x	X
2. Transformer (T-1)	X	x	X
3. Shunt Device	X		X
4. Bus section	X		X
P7 – Multiple Contingency - Fault plus stuck breaker			
1. Two circuits on common structure (L-2)	X	X	X
2. Bipolar DC line	X	X	X
Extreme event – loss of two or more elements			
Two generators (Common Mode) G-2	X[4]	X	X[4]
Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2	X[4]	X[3]	X[5]
All other extreme combinations.	X[4]		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.
5 Expanded to include any P1 system readjustment followed by any P7 without stuck breaker. For voltage collapse or dynamic instability situations mitigation is required "if there is a risk of cascading" beyond a relatively small predetermined area – less than 250 MW - directly affected by the outage.

Table 2.1-2: Criteria Comparison for non-Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	New Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X
2. Transmission Circuit (L-1)	X	X[1]	X
3. Transformer (T-1)	X	X[1,2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X[1]	X
P2 – Single contingency			
1. Opening a line section w/o a fault			
2. Bus Section fault			
3. Internal Breaker fault (non-Bus-tie Breaker)			
4. Internal Breaker fault (Bus-tie Breaker)			

<u>P3 – Multiple Contingency – G-1 + system adjustment and:</u> 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Shunt Device 5. Single Pole (dc) Line	 X X X X X	 X X X[2] X	 X X X X X
<u>P4 – Multiple Contingency - Fault plus stuck breaker</u> 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Shunt Device 5. Bus section 6. Bus-tie breaker			
<u>P5 – Multiple Contingency – Relay failure (delayed clearing)</u> 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Shunt Device 5. Bus section			
<u>P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:</u> 1. Transmission Circuit (L-1) 2. Transformer (T-1) 3. Shunt Device 4. Bus section		 x x	
<u>P7 – Multiple Contingency - Fault plus stuck breaker</u> 1. Two circuits on common structure (L-2) 2. Bipolar DC line		 X X	
<u>Extreme event – loss of two or more elements</u> Two generators (Common Mode) G-2 Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2 All other extreme combinations.		 X X[3]	

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.

A significant number of simulations were run to determine the most critical contingencies within each local area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all tested contingencies were measured against the system performance requirements defined by the criteria shown in Tables 1 and 2. Where the specific system performance requirements were not met, generation was adjusted until performance requirements were met for the local area. The adjusted generation constitutes the minimum generation needed in the local area. The following describes how the criteria were tested for the specific type of analysis performed.

2.1.19 Power Flow Assessment:

Table 2.1-3 Power flow criteria

Contingencies	Thermal Criteria[1]	Voltage Criteria[2]
P0	Applicable Rating	Applicable Rating
P1 [3]	Applicable Rating	Applicable Rating
P2	Applicable Rating	Applicable Rating
P3	Applicable Rating	Applicable Rating
P4	Applicable Rating	Applicable Rating
P5	Applicable Rating	Applicable Rating
P6 [4]	Applicable Rating	Applicable Rating
P7	Applicable Rating	Applicable Rating
P1 + P7 [4]	-	No Voltage Collapse

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

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

[3] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions and be able to safely prepare for the loss of the next most stringent element and be within Applicable Rating after the loss of the second element.

[4] 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.

2.1.20 Post Transient Load Flow Assessment:

Table 2.1-4 Post transient load flow criteria

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.

2.1.21 Stability Assessment:

Table 2.1-5 Stability criteria

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 – CAISO Grid Planning Criteria or facility owner criteria as appropriate.

2.1.22 Engineering Estimate for Intermediate Years:

Due to combined CEC/CPUC/CAISO timelines required by the RA process, the ISO must estimate LCR requirement for intermediate years, between the technical studies run for years one and five.

ISO will be using an engineering estimate for intermediate years. Elements of the engineering judgement estimates are described below:

2.1.22.1 *Net Peak Load Growth driven estimate*

Assuming nothing else changes, no transmission or resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease) in LCR, assuming a linear function, will be estimated based on ratio of load growth to ratio of LCR needs to be multiplied by the number of years using the following formula:

LCR for Year of Need = Year 1 LCR + [(Year 5 LCR-Year 1 LCR)/4] X (Year of Need-Year 1)

For non-linear functions, like voltage collapse or dynamic instability, ISO will use engineering judgment in order to provide estimated LCR requirement.

2.1.22.2 *Single New Transmission driven estimate*

Assuming nothing else changes, no load growth, no other new transmission projects or resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function (usually decreasing the LCR needs) in the year when the transmission project is supposed to be first operational (if in-service before June 1-st of estimated year for summer peaking areas).

2.1.22.3 *Single New Resource driven estimate*

Assuming nothing else changes, no load growth, no new transmission projects or any other resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function if:

a) The new resource is catalogued with a higher dispatch priority or the same priority as the marginal resource used for establishment of LCR need AND
b) The new resource has a significantly different (10% or more) effectiveness factor difference vs. the marginal resource used for the establishment of the LCR need.

Priority dispatch order (from LCR study manual):

1. QF/MUNI/State/Federal
2. RA resources under long-term contracts
3. Unknown contractual status

2.1.22.4 *Single Change in Resource contractual status driven estimate*

Assuming nothing else changes, no load growth, no new transmission projects or resource mix changes, including no changes to other long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function if:

a) The resource is moving to a higher dispatch priority or the same priority as the marginal resource used for establishment of LCR need AND
b) The resource has a significantly different (10% or more) effectiveness factor difference vs. the marginal resource used for the establishment of the LCR need.

2.1.22.5 *Single Known Resource Retirement driven estimate*

Assuming nothing else changes, no load growth, no new transmission projects or other resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function if:

a) The retired resource was included in a higher dispatch priority or the same priority as the marginal resource used for establishment of LCR need AND
b) The resource has a significantly different (10% or more) effectiveness factor difference vs. the marginal resource used for the establishment of the LCR need.

2.1.22.6 *Multi Reason Change driven estimate*

From multi-year available LCR studies the ISO will use engineering judgement, guided by the above explain single change principles, in order to estimate intermediate year LCR needs any time more than one factor is influencing the LCR results:

a) Net peak load growth

b) New transmission project(s)

c) New resource(s)

d) Change in resource contractual status

e) Known resource retirement(s)

2.2 Load Forecast

2.2.1 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.

2.2.2 Base Case Load Development Method

The method used to develop the load 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.

2.2.2.1 *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[7] 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.

a. 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

[7] 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 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 the division.

b. Allocation of division load to transmission bus level

Since the loads in the base case 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 base case loads 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.

2.2.2.2 *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.

2.3 Power Flow Program Used in the LCR analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 21.0_07 and PowerGem's Transmission Adequacy and Reliability Assessment (TARA) program version 1902. 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. A 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 PSLF 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.

2.4 Estimate of Battery Storage Needs due to Charging Constraints

Local areas and sub-areas have limited transmission capability and therefore rely on internal resources to be available in order to reliably serve internal load. Battery storage will help serve local load during the discharge cycle, however it will also increase local load during the charging cycle.

Due to recent procurement activities geared toward the acquisition of this type of technology, the CAISO is herein estimating the characteristics (MW, MWh, discharge duration) required from battery storage technology in order to seamlessly integrate in each local area and sub-area.

The CAISO expects that for batteries that displace other local resource adequacy resources, the transmission capability under the most limiting contingency and the other local capacity resources must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period.

For each local area and sub-area, the CAISO has estimated the battery storage characteristics, given their unique load shape, constraints and requirements as well as the energy characteristics of other resources required to meet standards. Due to this fact, the strict addition of the sub-area battery storage characteristics (MW, MWh and duration) may not closely align with the overall local area battery storage characteristic requirements (MW, MWh and duration).

Assumptions

1) Total load serving capability includes capability from transmission system and local generation needed for LCR under the worst contingency.
2) Storage added replaces existing generation MW for MW. First the batteries will replace as much as possible of existing gas resources, Second if the area and/or sub-area has run out of gas resources to displace then other technologies may be reduced in order to determine the maximum battery charging limit.
3) Effectiveness factors are assumed not to be a factor. Battery storage is assumed to be installed at the same sites where resources are displaced or assumed to have the same effectiveness factors.
4) Deliverability of incremental storage capacity is not evaluated. It is assumed battery storage will take over deliverability from old resources through repower. Any new battery storage resource needs to go through the generation interconnection process in order to receive deliverability and it is not evaluated in this study. CAISO cannot guaranty that there is enough deliverability available for new resources. New transmission upgrades may be required in order to make such new resources deliverable to the aggregate of load.
5) Includes battery storage charging/discharging efficiency of 85%.

6) Daily charging required is distributed to all non-discharging hours proportionally using delta between net load and the total load serving capability.

7) Energy required for charging, beyond the transmission capability under contingency condition, is produced by other LCR required resources within the local area and sub-area that are available for production during off-peak hours.

8) Hydro resources are considered to be available for production during off-peak hours, however these resources are energy limited themselves and based on past availability data they can have severely limited output during off-peak hours especially during late summer peaks under either normal or dry hydro years.

9) The study assumes the ability to provide perfect dispatch and the ability to enforce charging requirements for multiple contingency conditions (like N-1-1) in the day ahead time frame while the system is under normal (no contingency) conditions. CAISO software improvements and/or augmentations are required in order to achieve this goal.

Installing battery storage with insufficient characteristics (MW, MWh and duration) will not result in a one for one reduction of the local area or sub-area need for other types of resources. The CAISO expects that the overall RA portfolio provided by all LSEs to account for the uplift, beyond the minimum LCR need, in MWs required from other type of resources for all areas and sub-areas where LSEs have procured battery storage beyond the charging capability or with incorrect characteristics (MW, MWh and duration). If uplift is not provided the CAISO may use its back stop authority to assure that reliability standards are met throughout the day, including off-peak hours.

3. Locational Capacity Requirement Study Results

3.1 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 3.1-1 2021 Local Capacity Needs vs. Peak Load and Local Area Resources

	2021 Total LCR (MW)	Peak Load (1 in10) (MW)	2021 LCR as % of Peak Load	Total NQC Local Area Resources (MW)	2021 LCR as % of Total NQC
Humboldt	130	153	85%	191	68%
North Coast/North Bay	842	1456	58%	842	100%**
Sierra	1821	1865	98%	2108	86%**
Stockton	596	1113	54%	596	100%**
Greater Bay	6353	10780	59%	7418	86
Greater Fresno	1694	3189	53%	3392	50%**
Kern	413	1285	32%	413	100%**
Big Creek/Ventura	2296	4451	52%	5128	45%
LA Basin	6127	18930	32%	9664	63%
San Diego/Imperial Valley	3888	4523	86%	4361	89%
Total*	24160	47745	51%	34113	71%

Table 3.1-2 2020 Local Capacity Needs vs. Peak Load and Local Area Resources

	2020 Total LCR (MW)	Peak Load (1 in10) (MW)	2020 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2020 LCR as % of Total Area Resources
Humboldt	130	153	85%	197	66%
North Coast/North Bay	742	1492	50%	833	89%
Sierra	1764	1862	95%	2160	82%**
Stockton	629	1275	49%	653	96%**
Greater Bay	4550	10488	43%	7067	64%
Greater Fresno	1694	3278	52%	3158	54%**
Kern	465	1169	40%	465	100%**
LA Basin	2410	4956	49%	5050	48%
Big Creek/Ventura	7364	19261	38%	10439	71%
San Diego/Imperial Valley	3895	4613	84%	4334	90%
Total*	23643	48547	49%	34356	69%

* Value shown only illustrative, since each local area peaks at a different time.

** Resource deficient LCA (or with sub-area that are deficient). Resource deficient area implies that in order to comply with the criteria, at summer peak, load must be shed immediately after the first contingency.

Table 3.1-1 and Table 3.1-2 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 "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. Units scheduled to become operational before June 1 of 2021 have been included in this 2021 LCT Study Report and added to the total NQC values for those respective areas (see detail write-up for each area).

Regarding the main tables up front (page 2), the first column, "August Qualifying Capacity," reflects three 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, municipal and QFs). The second set is "market" based resources (market, net seller, wind and battery). The third set are solar resources, since they may or may not be available during the actual peak hour for the respective local area. The second column, "Capacity at Peak" identifies how much of the August Qualifying Capacity is expected to be available during the peak time for each particular local area. The third column, "YEAR LCR Need", sets forth the local capacity requirements, without the deficiencies that must be addressed, necessary to attain a service reliability level required to comply with NERC/WECC/CAISO mandatory reliability standards.

Table 3.1-3 includes estimated characteristics (MW, MWh, discharge duration) required from battery storage technology in order to seamlessly integrate in each local area and sub-area.

The CAISO expects that for batteries that displace other local resource adequacy resources, the transmission capability under the most limiting contingency and the other local capacity resources must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period.

Table 3.1-3 2021 Battery Storage Characteristics Limited by Charging Capability

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	Replacing mostly	Comment
Humboldt	48	240	9	gas	
North Coast/North Bay Overall	235	2350	11	geothermal	
Eagle Rock	30	240	9	geothermal	
Fulton	60	600	16	geothermal	

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	Replacing mostly	Comment
Sierra	-	-	-	-	Flow through
Placer	55	495	10	hydro	
Pease	50	400	9	gas	Need to be eliminated
Gold Hill-Drum	0	0	0	-	
Stockton	-	-	-	-	Sum of sub-areas
Lockeford	100	800	9	gas	Need to be eliminated
Tesla-Bellota	0	0	0	-	
Greater Bay Overall	1950	19500	11	gas	
Llagas	130	780	7	gas	
San Jose	325	3250	14	gas	
South Bay-Moss Landing	400	3600	12	gas	
Oakland	22	264	16	distillate	
Greater Fresno Overall	1100	9900	10	hydro	
Panoche	130	1170	10	gas	
Herndon	340	3060	10	hydro	
Hanford	0	0	0	-	
Coalinga	0	0	0	-	
Reedley	0	0	0	-	
Kern Overall	-	-	-	-	N/A
Westpark	65	390	11	gas	
Kern 70 kV	0	0	0	-	
Kern Oil	0	0	0	-	
South Kern PP	0	0	0	-	
Big Creek/Ventura Overall[8]	1047	7147	10	gas	Need to be eliminated
Vestal	-	-	-	gas	
Santa Clara	130	960	12	gas	
LA Basin Overall	4300	43000	11	gas	
Eastern	1700	17000	11	gas	LA Basin split
Western	2600	26000	11	gas	LA Basin split
El Nido	250	2000	9	gas	
San Diego/Imperial Valley Overall	950	8550	10	gas	
San Diego	950	8550	10	gas	

[8] The energy storage analysis performed for Big Creek–Venura area and its sub-areas is based on energy storage replacing gas fired local capacity. Further studies will be performed, if needed, to determine the amount of storage that can be added to replace the hydro, solar and demand response local capacity available in the area.

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	Replacing mostly	Comment
El Cajon	48	432	10	gas	
Border	160	800	7	gas	

3.2 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. Table 3.2-1 shows the total resources needed (based on the latest CEC load forecast) in each the two relevant zones, SP26 and NP26.

Table 3.2-1 Total Zonal Resource Needs

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Maximum Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	27488	4123	-7108	-3750	**20753**
NP26=NP15+ZP26	20100	3015	-3645	-3000	**16470**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2021 - California Energy Demand 2020-2030 Revised Forecast, Mid Demand Baseline, Mid AAEE Savings dated March 4, 2020.

Reserve Margin is 15% the minimum CPUC approved planning reserve margin.

Allocated Imports are the actual 2020 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2021 because there are no additional import transmission additions to the grid.

Maximum Path 26 flow The CAISO determines the maximum amount of Path 26 transfer capacity available after accounting for (1) Existing Transmission Contracts (ETCs) that serve load outside the CAISO Balancing Area[9] and (2) loop flow[10] from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North).

[9] 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.

[10] "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.

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.

3.2.19.1 *Changes compared to last year's results:*

The load forecast went up in Southern California by about 500 MW while Northern California stayed about the same.

The Import Allocations went up in Southern California by about 50 MW and up in Northern California by about 250 MW.

The Path 26 maximum transfer capability has not changed and is not envisioned to change in the near future.

3.3 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.

3.3.1 Humboldt Area

3.3.1.1 *Area Definition*

The transmission tie lines into the area include:

Bridgeville-Cottonwood 115 kV line #1

Humboldt-Trinity 115 kV line #1

Laytonville-Garberville 60 kV line #1

Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

Bridgeville is in, Low Gap, Wildwood and Cottonwood are out

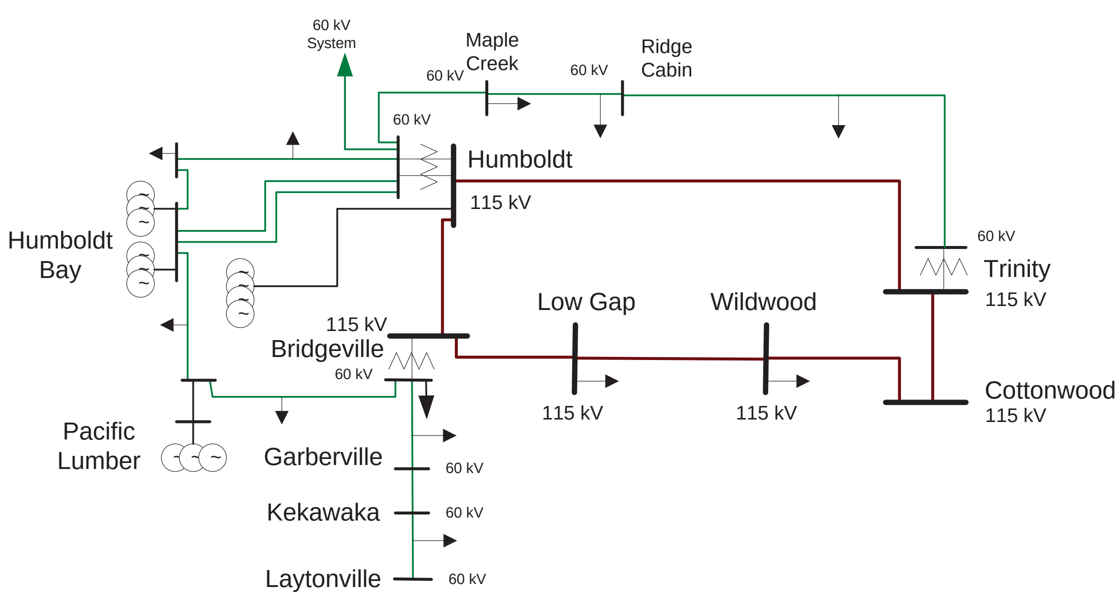
Humboldt is in, Trinity is out

Kekawaka and Garberville are in, Laytonville is out

Maple Creek is in, Trinity and Ridge Cabin are out

Humboldt LCR Area Diagram

Figure 3.3-1 Humboldt LCR Area



Humboldt LCR Area Load and Resources

Table 3.3-1 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 18:40 PM.

This area does not contain models of solar resources capable of providing resource adequacy.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-1 Humboldt LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	151	Market and Net Seller	191	191
AAEE	-8	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	143	LTPP Preferred Resources	0	0
Transmission Losses	10	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	153	Total	191	191

Humboldt LCR Area Hourly Profiles

Figure 3.3-2 illustrates the forecast 2021 profile for the peak day for the Humboldt LCR area with the Category P6 transmission capability without resources. Figure 3.3-3 illustrates the forecast 2021 hourly profile for Humboldt LCR area with the Category P6 transmission capability without resources.

Figure 3.3-2 Humboldt 2021 Peak Day Forecast Profiles

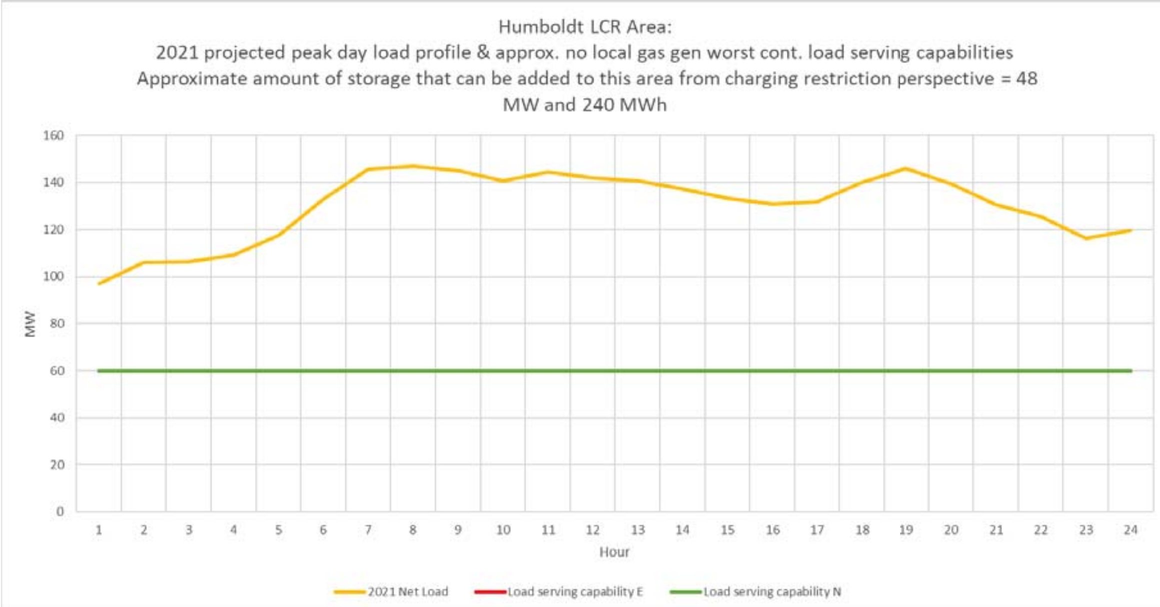
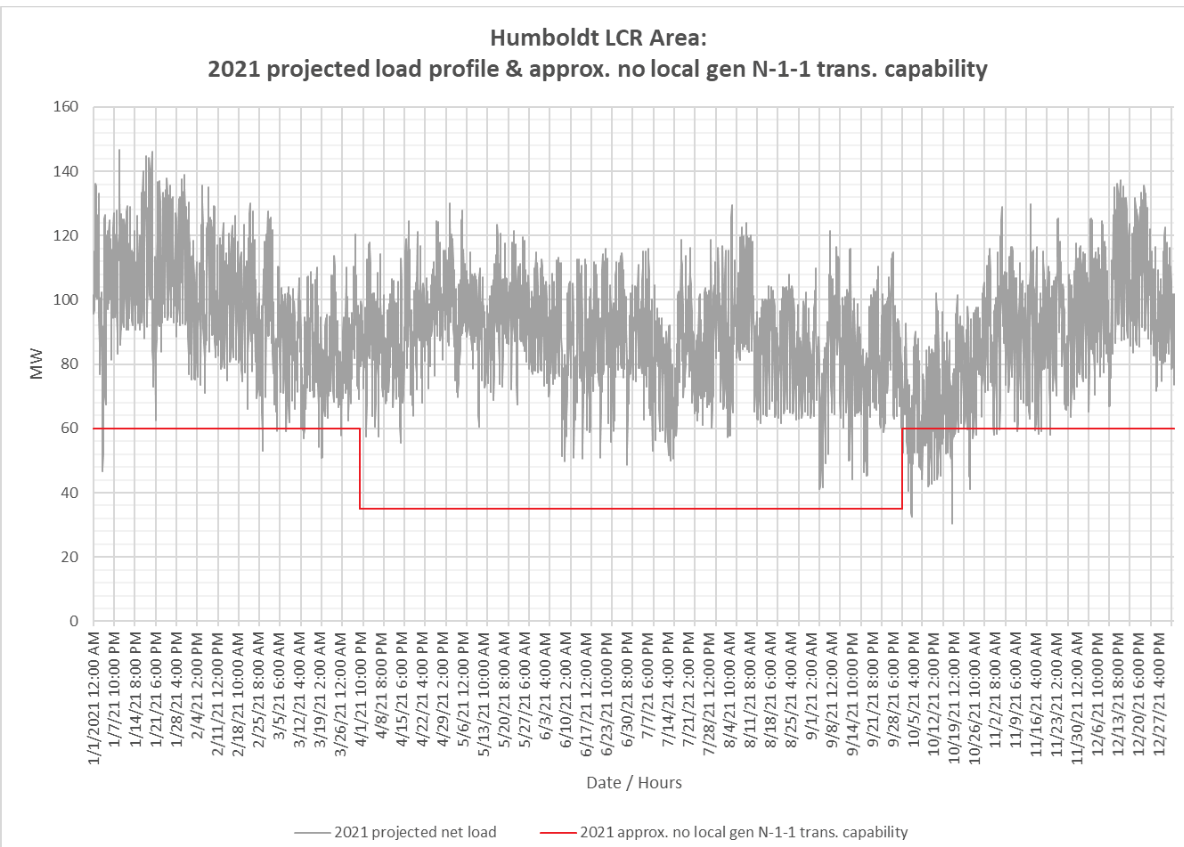


Figure 3.3-3 Humboldt 2021 Forecast Hourly Profile



Approved transmission projects included in base cases

None

3.3.1.2 *Humboldt Overall LCR Requirement*

Table 3.3-2 identifies the area LCR requirements. The LCR requirement for Category P6 contingency is 130 MW.

Table 3.3-2 Humboldt LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115 kV & Humboldt - Humboldt Bay 115 kV	130

Effectiveness factors

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

Changes compared to last year's results

Compared with 2020 the load forecast and the total LCR are the same.

3.3.2 North Coast / North Bay Area

3.3.2.1 *Area Definition*

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

Cortina-Mendocino 115 kV Line

Cortina-Eagle Rock 115 kV Line

Willits-Garberville 60 kV line #1

Vaca Dixon-Lakeville 230 kV line #1

Tulucay-Vaca Dixon 230 kV line #1

Lakeville-Sobrante 230 kV line #1

Ignacio-Sobrante 230 kV line #1

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

Cortina is out, Mendocino and Indian Valley are in

Cortina is out, Eagle Rock, Highlands and Homestake are in

Willits and Lytonville are in, Kekawaka and Garberville are out

Vaca Dixon is out, Lakeville is in

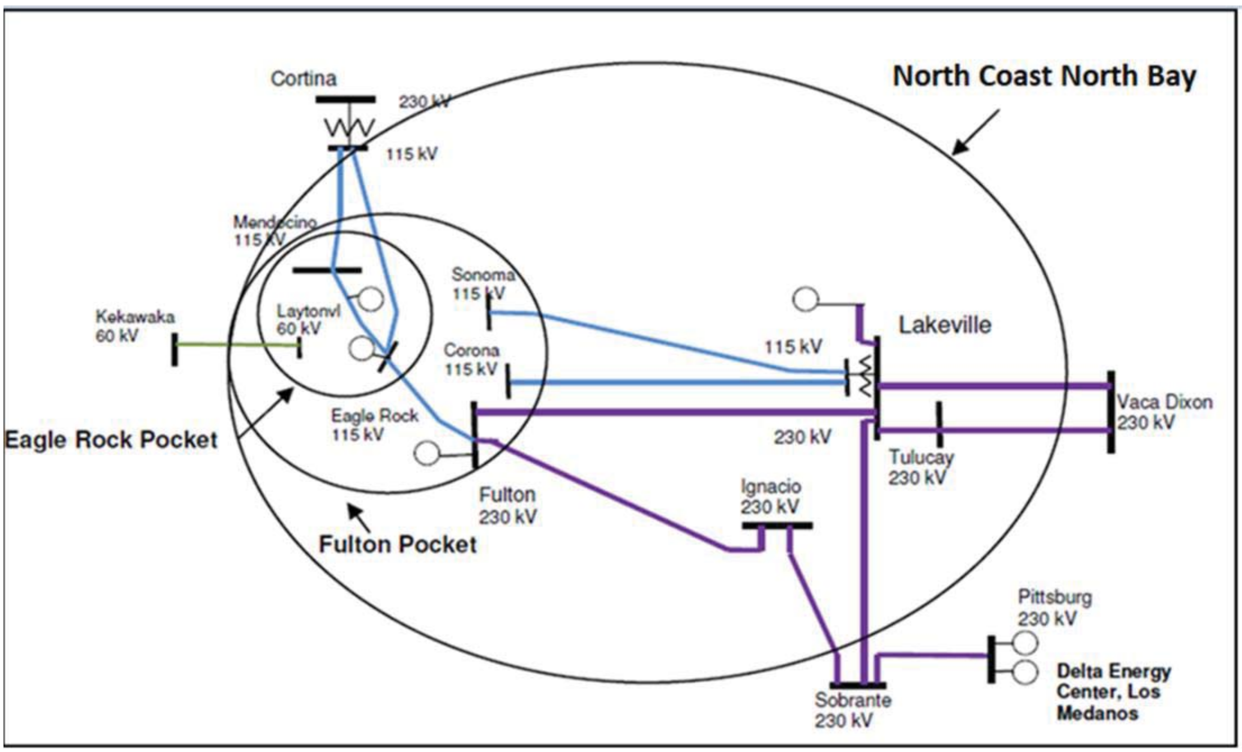
Tulucay is in, Vaca Dixon is out

Lakeville is in, Sobrante is out

Ignacio is in, Sobrante and Crocket are out

North Coast and North Bay LCR Area Diagram

Figure 3.3-4 North Coast and North Bay LCR Area



North Coast and North Bay LCR Area Load and Resources

Table 3.3-3 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 17:50 PM.

This area does not contain models of solar resources capable of providing resource adequacy.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-3 North Coast and North Bay LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1425	Market and Net Seller	723	723
AAEE	-7	MUNI	114	114
Behind the meter DG	0	QF	5	5
Net Load	1418	Wind	0	0
Transmission Losses	38	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	1456	Total	842	842

North Coast and North Bay LCR Area Hourly Profiles

Figure 3.3-5 5 illustrates the forecast 2021 profile for the peak day for the North Coast North Bay LCR sub-area with the Category P2-4 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-6 illustrates the forecast 2021 hourly profile for North Coast North Bay LCR sub-area with the Category P2-4 emergency load serving capability without local gas resources.

Figure 3.3-5 North Coast and North Bay 2021 Peak Day Forecast Profiles

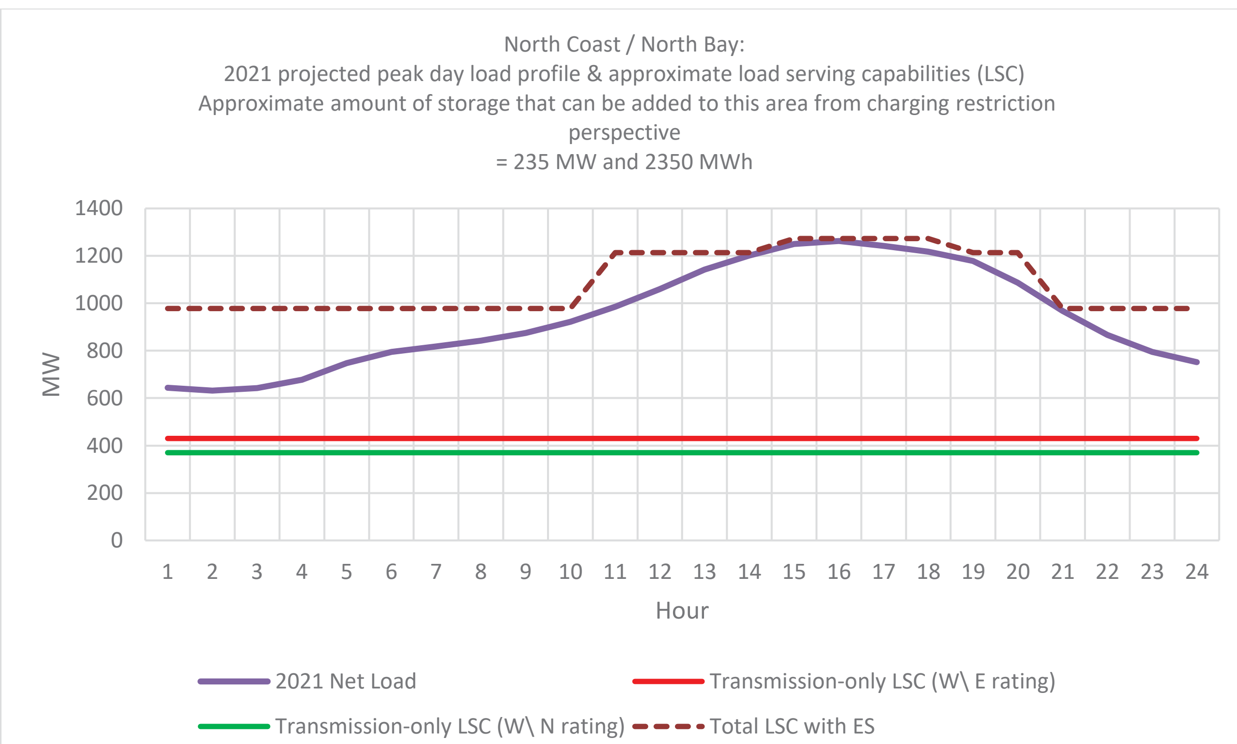
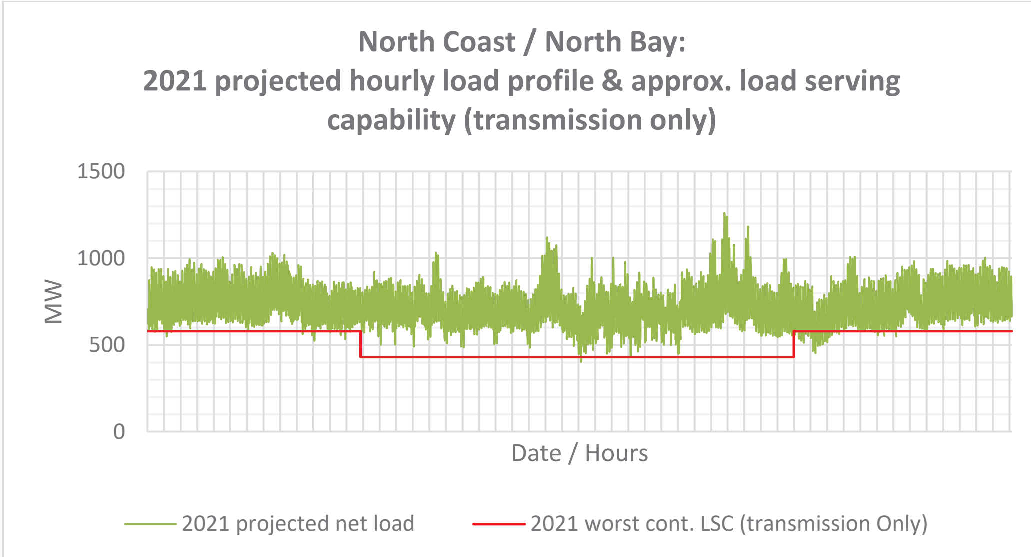


Figure 3.3-6 North Coast and North Bay 2021 Forecast Hourly Profile



Approved transmission projects modeled in base cases

Lakeville 60 kV Area System Reinforcement

Clear Lake 60 kV System Reinforcement

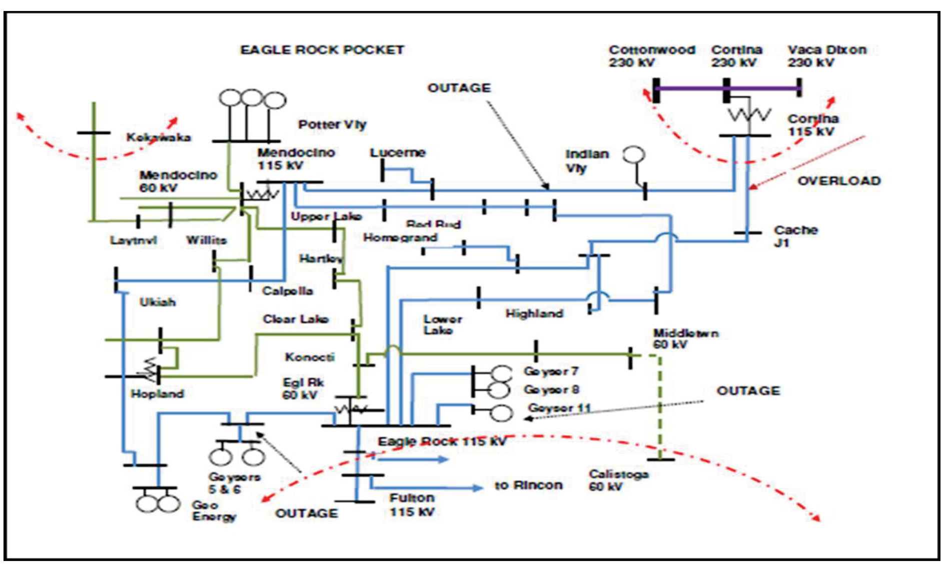
Ignacio Area Upgrade

3.3.2.2 *Eagle Rock LCR Sub-area*

Eagle Rock is a Sub-area of the North Coast and North Bay LCR Area.

Eagle Rock LCR Sub-area Diagram

Figure 3.3-7 Eagle Rock LCR Sub-area



Eagle Rock LCR sub-area Load and Resources

Table 3.3-4 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-4 Eagle Rock LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	222	Market and Net Seller	248	248
AAEE	-1	MUNI	2	2
Behind the meter DG	0	QF	0	0
Net Load	221	Solar	0	0
Transmission Losses	11	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	232	Total	250	250

Eagle Rock LCR Sub-area Hourly Profiles

Figure 3.3-8 illustrates the forecast 2021 profile for the peak day for the Eagle Rock LCR sub-area with the Category P3 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-9 illustrates the forecast 2021 hourly profile for Eagle Rock LCR sub-area with the Category P3 emergency load serving capability without local gas resources.

Figure 3.3-8 Eagle Rock LCR Sub-area 2021 Peak Day Forecast Profiles

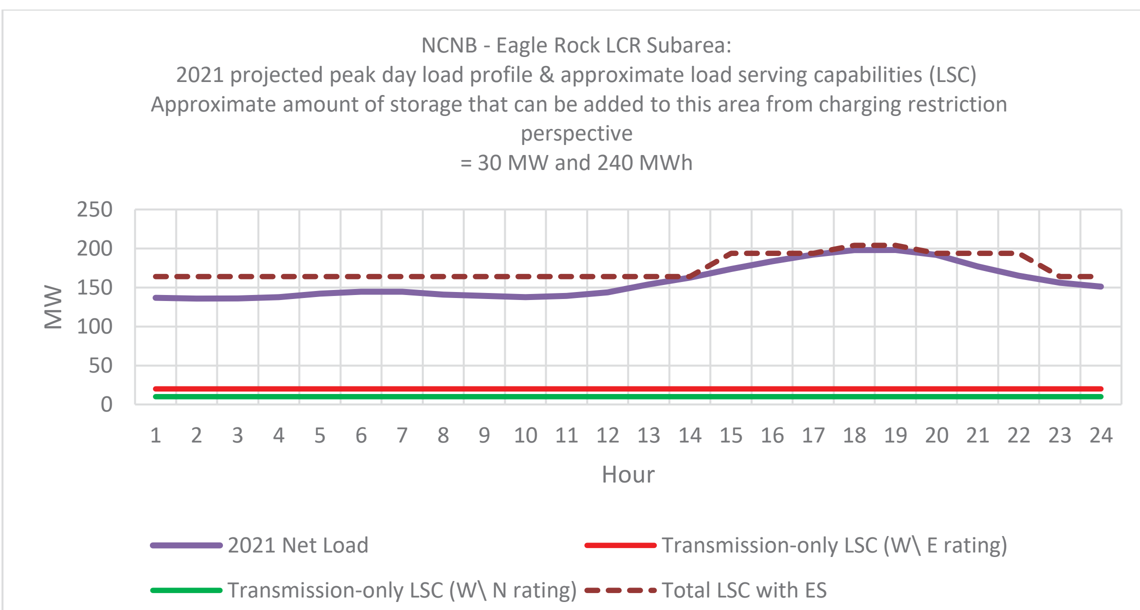
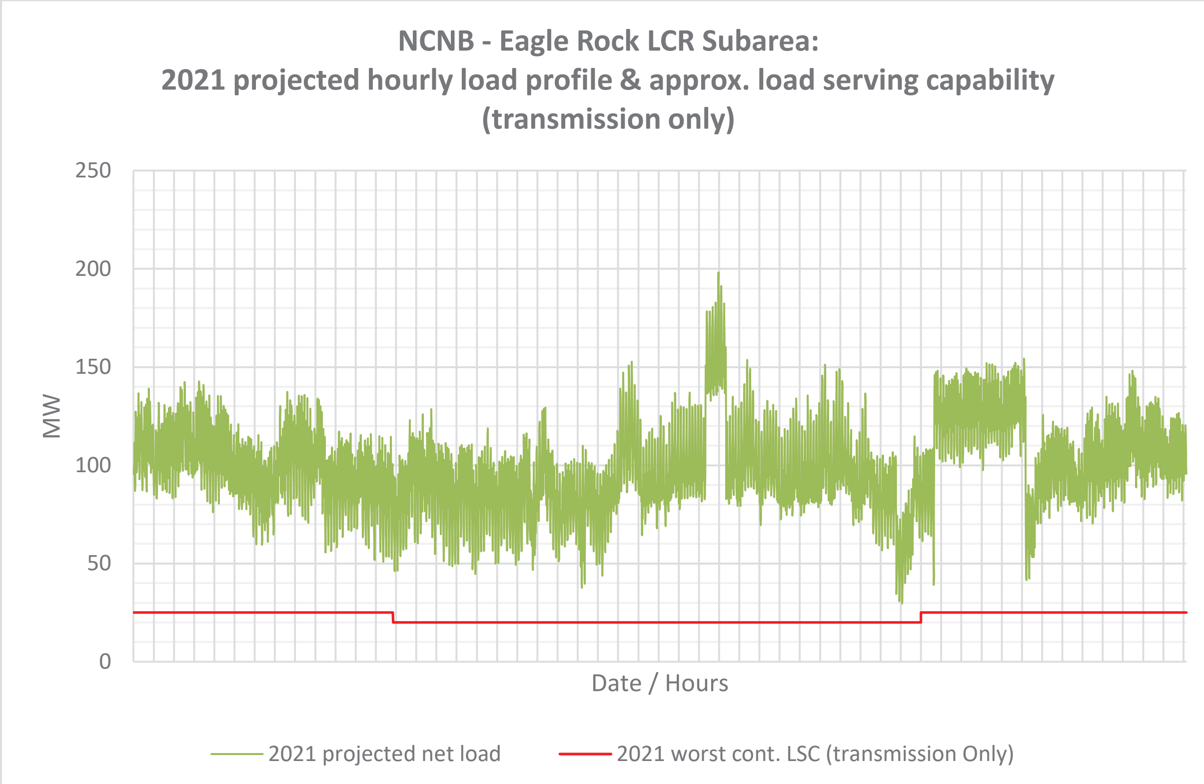


Figure 3.3-9 Eagle Rock LCR Sub-area 2021 Forecast Hourly Profiles



Eagle Rock LCR Sub-area Requirement

Table 3.3-5 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 184 MW.

Table 3.3-5 Eagle Rock LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P3	Eagle Rock-Cortina 115 kV line	Cortina-Mendocino 115 kV with Geyser #11 unit out	184

Effectiveness factors

Effective factors for generators in the Eagle Rock LCR sub-area are in Attachment B table titled Eagle Rock.

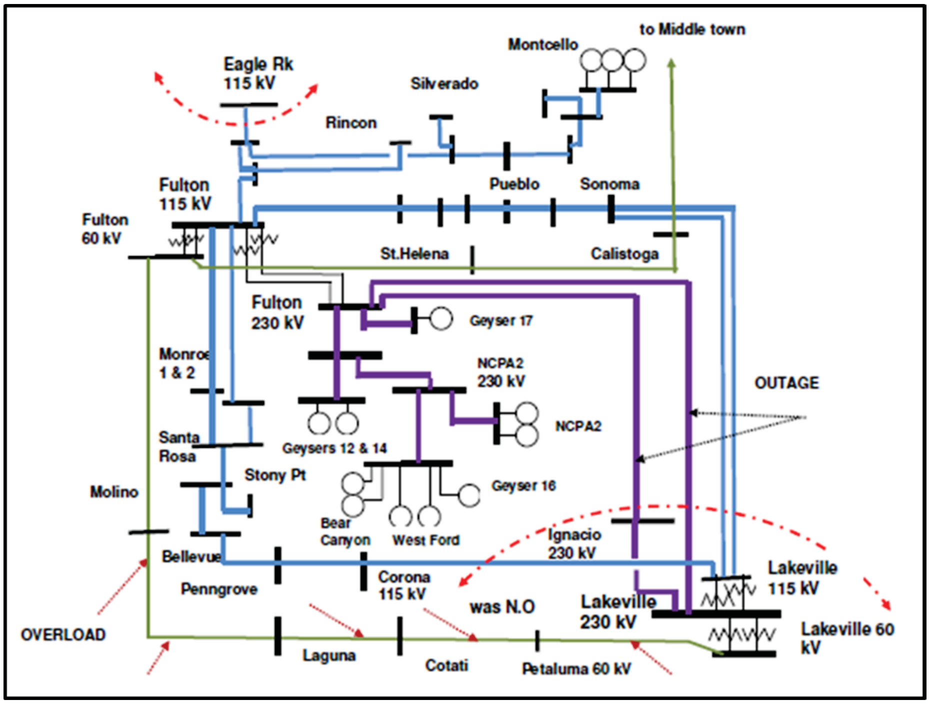
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7120 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.2.3 *Fulton Sub-area*

Fulton is a Sub-area of the North Coast and North Bay LCR Area.

Fulton LCR Sub-area Diagram

Figure 3.3-10 Fulton LCR Sub-area



Fulton LCR Sub-area Load and Resources

Table 3.3-6 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-6 Fulton LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	848	Market	469	469
AAEE	-4	MUNI	54	54
Behind the meter DG	0	QF	5	5
Net Load	844	Solar	0	0
Transmission Losses	22	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	866	Total	528	528

Fulton LCR Sub-area Hourly Profiles

Figure 3.3-11 illustrates the forecast 2021 profile for the peak day for the Fulton LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-12 illustrates the forecast 2021 hourly profile for Fulton LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-11 Fulton LCR Sub-area 2021 Peak Day Forecast Profiles

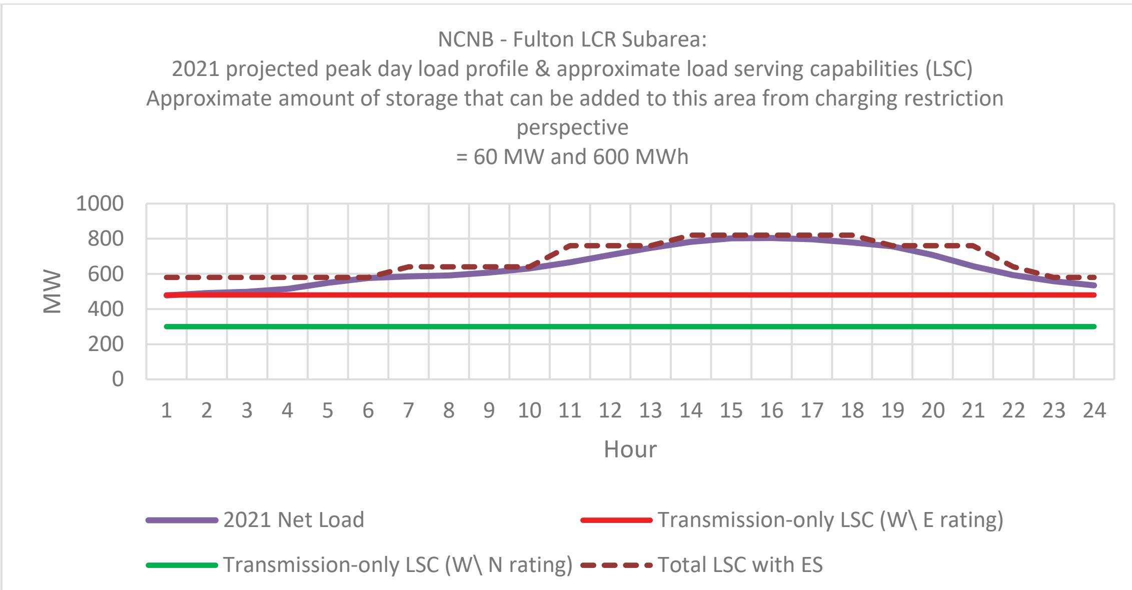
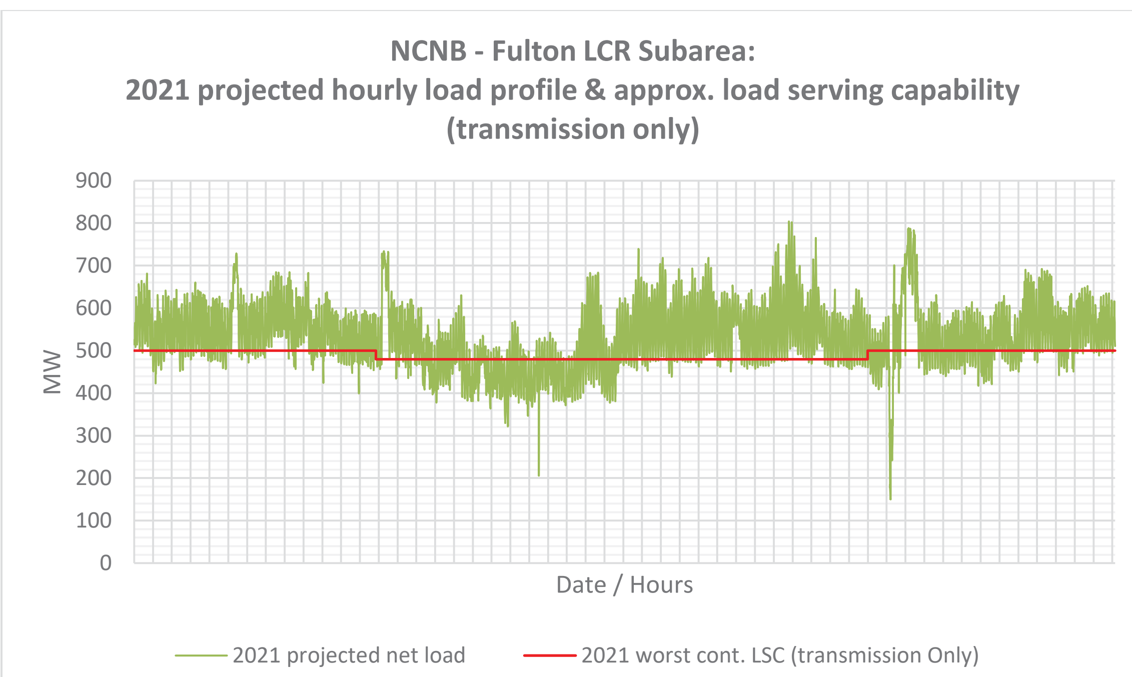


Figure 3.3-12 Fulton LCR Sub-area 2021 Forecast Hourly Profiles



Fulton LCR Sub-area Requirement

Table 3.3-7 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 340 MW. There is a significant LCR reduction because of the Lakeville 60 kV Area Reinforcement project in service in 2021 that opens the 60 kV line berween Cotati and Petaluma.

Table 3.3-7 Fulton LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	-Sonoma-Pueblo 115 kV line	Fulton-Lakeville #1 230 kV & Fulton-Ignacio #1 230 kV	340

Effectiveness factors

Effective factors for generators in the Fulton LCR sub-area are in Attachment B table titled Fulton.

3.3.2.4 *North Coast and North Bay Overall*

North Coast and North Bay Overall Requirement

Table 3.3-8 identifies the sub-area LCR requirements. The LCR requirement for Category P2-4 contingency is 843 and for Category P3 contingency is 766 MW.

Table 3.3-8 North Coast and North Bay LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P2-4	Tulucay - Vaca Dixon 230 kV Line	Lakeville 230 kV – Section 2E & 1E	843 (1)
2021	Second Limit	P3	Vaca Dixon-Lakeville 230 kV Line	Vaca Dixon-Tulucay 230 kV with DEC power plant out of service	766

Effectiveness factors

Effective factors for generators in the North Coast and North Bay LCR area are in Attachment B table titled North Coast and North Bay.

Changes compared to last year's results

Compared to 2020 load forecast went down by 36 MW; however, the total LCR need went up by 101 MW due to the LCR criteria change.

3.3.3 Sierra Area

3.3.3.1 *Area Definition*

The transmission tie lines into the Sierra Area are:

Table Mountain-Rio Oso 230 kV line

Table Mountain-Palermo 230 kV line

Table Mt-Pease 60 kV line

Caribou-Palermo 115 kV line

Drum-Summit 115 kV line #1

Drum-Summit 115 kV line #2

Spaulding-Summit 60 kV line

Brighton-Bellota 230 kV line

Rio Oso-Lockeford 230 kV line

Gold Hill-Eight Mile Road 230 kV line

Lodi-Eight Mile Road 230 kV line

Gold Hill-Lake 230 kV line

The substations that delineate the Sierra Area are:

Table Mountain is out Rio Oso is in

Table Mountain is out Palermo is in

Table Mt is out Pease is in

Caribou is out Palermo is in

Drum is in Summit is out

Drum is in Summit is out

Spaulding is in Summit is out

Brighton is in Bellota is out

Rio Oso is in Lockeford is out

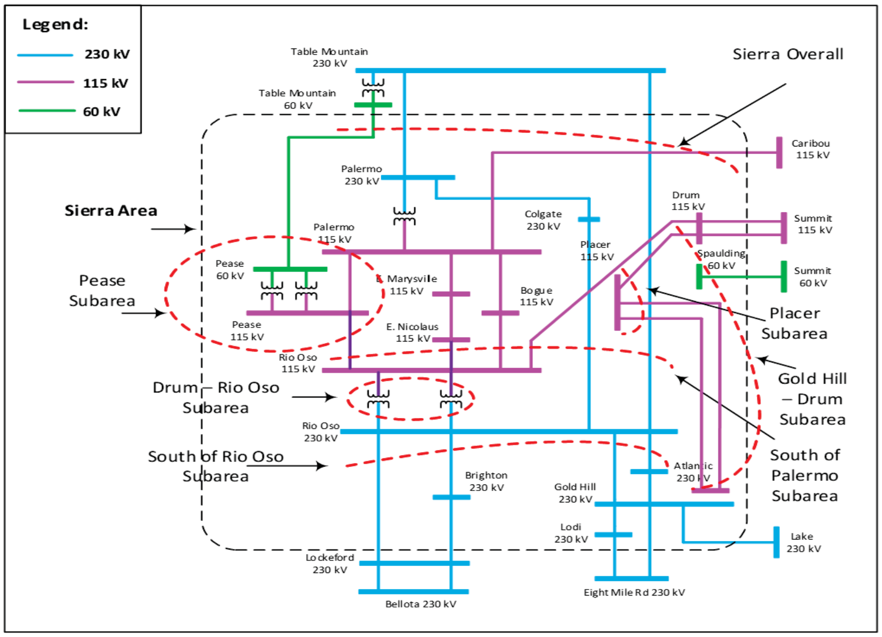
Gold Hill is in Eight Mile is out

Lodi is in Eight Mile is out

Gold Hill is in Lake is out

Sierra LCR Area Diagram

Figure 3.3-13 Sierra LCR Area



Sierra LCR Area Load and Resources

Table 3.3-9 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 19:10 PM.

At the local area peak time the estimated, ISO metered, solar output is 2.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-9 Sierra LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1789	Market and Net Seller	920	920
AAEE	-7	MUNI	1142	1142
Behind the meter DG	0	QF	41	41
Net Load	1782	Solar	5	0
Transmission Losses	84	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	1865	Total	2108	2103

Approved transmission projects modeled:

South of Palermo 115 kV Reinforcement Project (Pease to Palermo Line)

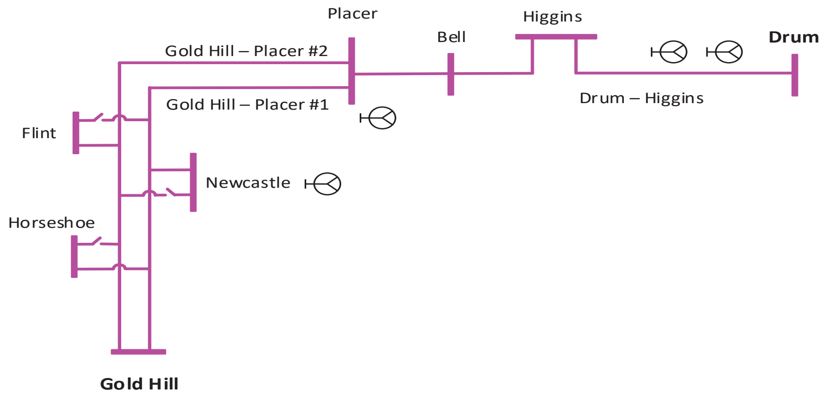
Pease 115/60 kV transformer addition

3.3.3.2 *Placer Sub-area*

Placer is Sub-area of the Sierra LCR Area.

Placer LCR Sub-area Diagram

Figure 3.3-14 Placer LCR Sub-area



Placer LCR Sub-area Load and Resources

Table 3.3-10 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-10 Placer LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	174	Market and Net Seller	54	54
AAEE	-1	MUNI	42	42
Behind the meter DG	0	QF	0	0
Net Load	173	Solar	0	0
Transmission Losses	5	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	178	Total	96	96

Placer LCR Sub-area Hourly Profiles

Figure 3.3-15 illustrates the forecast 2021 profile for the peak day for the Placer sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area. Figure 3.3-16 illustrates the forecast 2021 hourly profile for Placer sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-15 Placer LCR Sub-area 2021 Peak Day Forecast Profiles

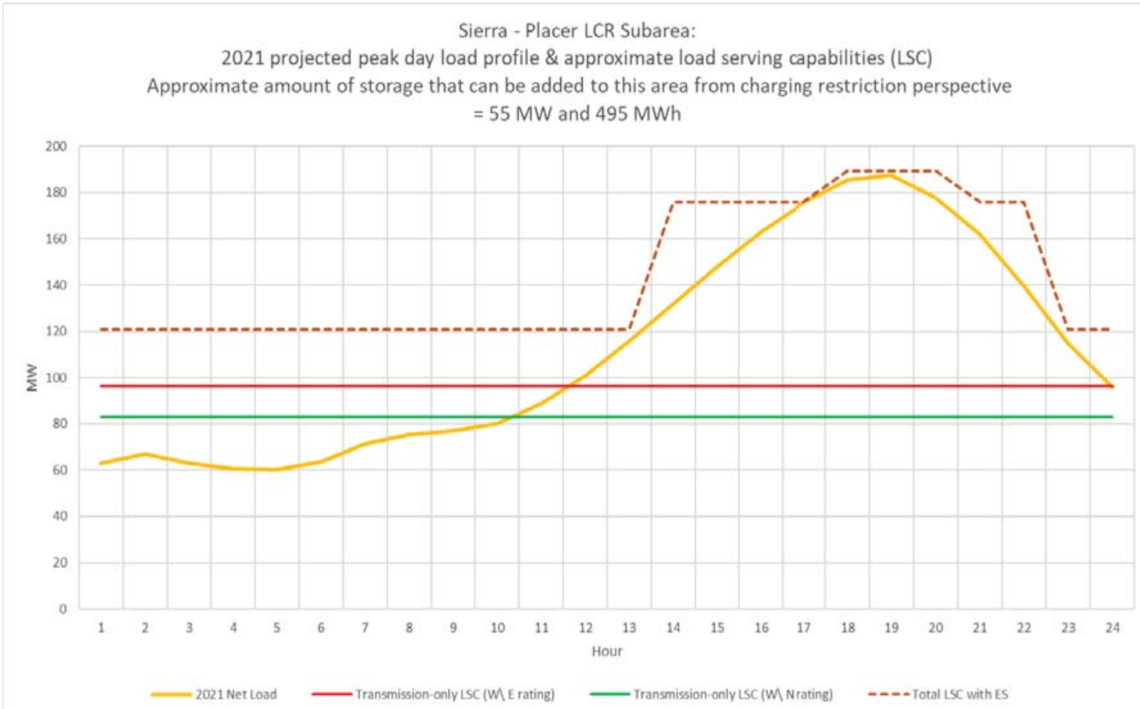
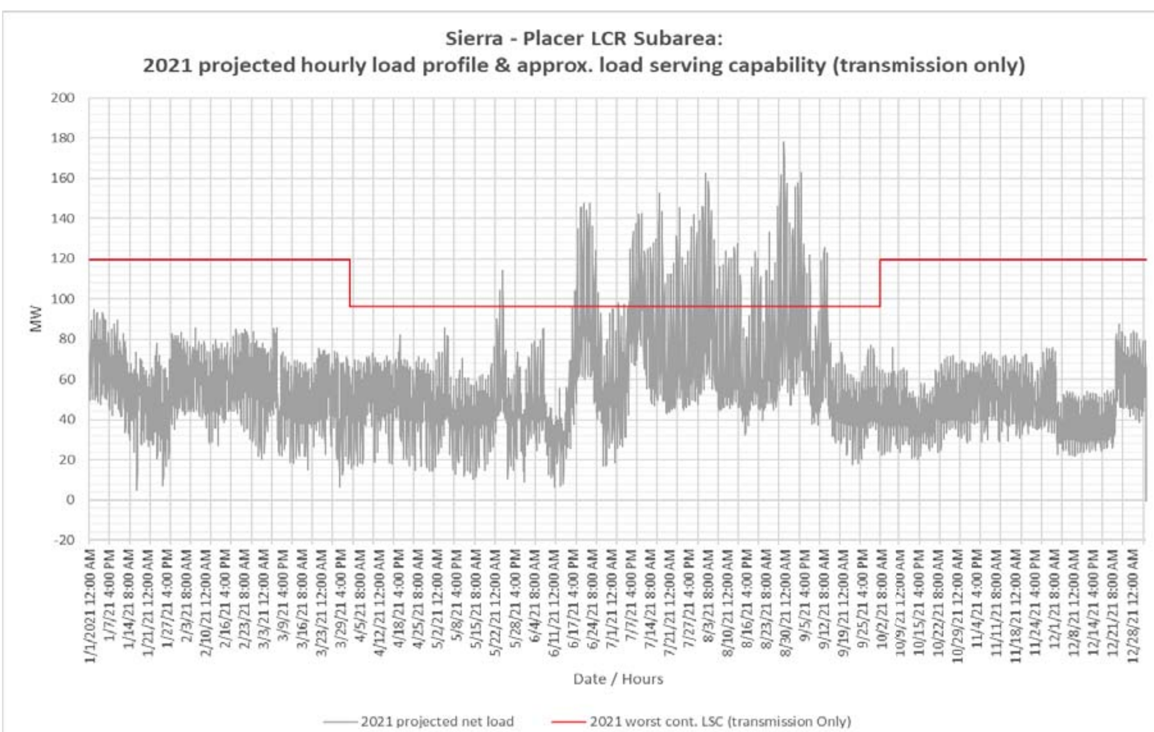


Figure 3.3-16 Placer LCR Sub-area 2021 Forecast Hourly Profiles



Placer LCR Sub-area Requirement

Table 3.3-11 identifies the sub-area requirements. The Category P6 LCR requirement is 93 MW.

Table 3.3-11 Placer LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Drum–Higgins 115 kV	Gold Hill-Placer #1 115 kV & Gold Hill-Placer #2 115 kV	93

Effectiveness factors

All units within the Placer Sub-area have the same effectiveness factor.

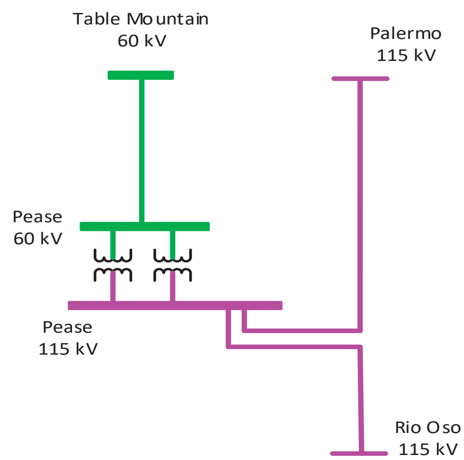
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.3 *Pease Sub-area*

Pease is sub-area of the Sierra LCR area.

Pease LCR Sub-area Diagram

Figure 3.3-17 Pease LCR Sub-area



Pease LCR Sub-area Load and Resources

Table 3.3-12 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-12 Pease LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	154	Market and Net Seller	98	98
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	39	39
Net Load	153	Solar	0	0
Transmission Losses	3	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	156	Total	137	137

Pease LCR Sub-area Hourly Profiles

Figure 3.3-18 illustrates the forecast 2021 profile for the peak day for the Pease sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-19 illustrates the forecast 2021 hourly profile for Pease sub-area with the Category P6 load serving capability without local gas resources.

Figure 3.3-18 Pease LCR Sub-area 2021 Peak Day Forecast Profiles

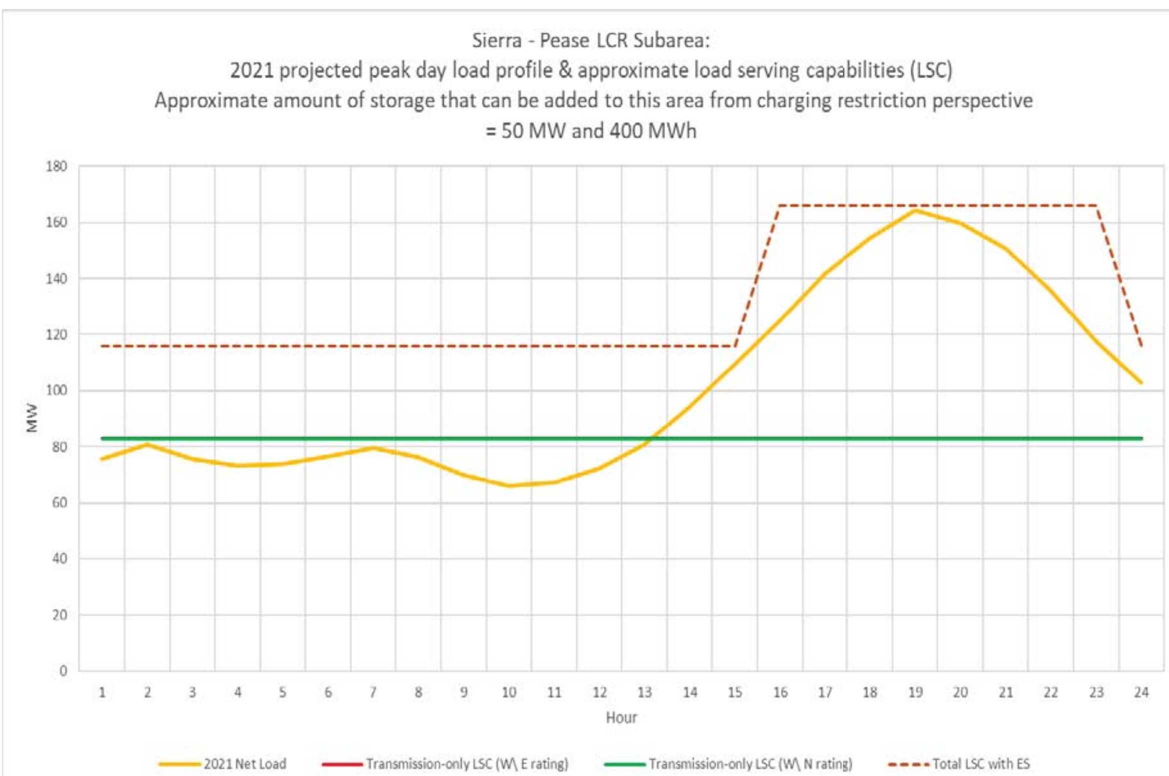
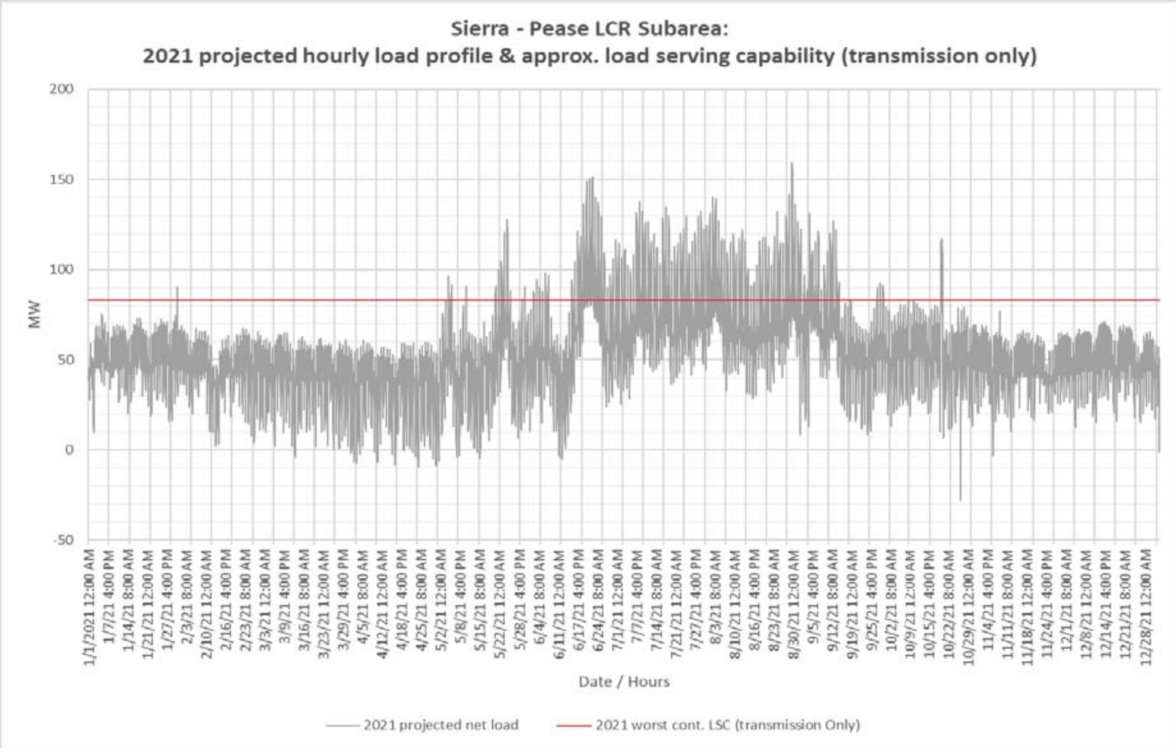


Figure 3.3-19 Pease LCR Sub-area 2021 Forecast Hourly Profiles



Pease LCR Sub-area Requirement

Table 3.3-13 identifies the sub-area LCR requirements. The Category P6 LCR requirement is 83 MW.

Table 3.3-13 Pease LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Table Mountain – Pease 60 kV	Palermo – Pease 115 kV and Pease – Rio Oso 115 kV lines	83

Effectiveness factors:

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

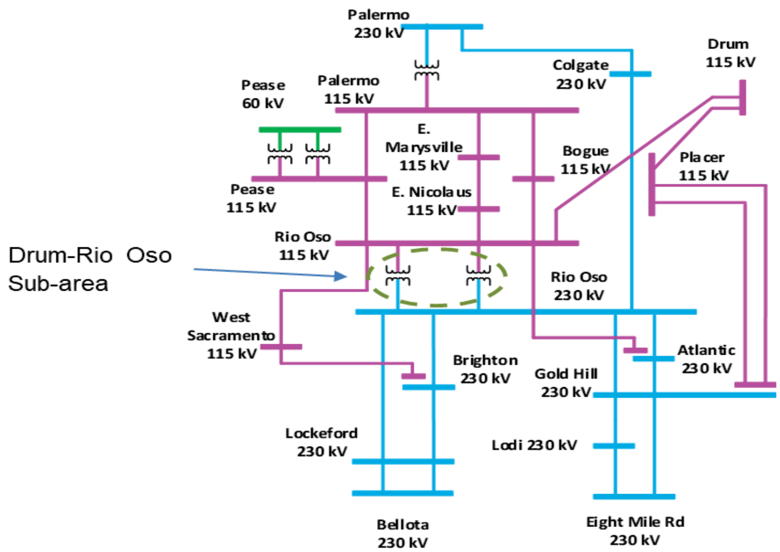
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.4 *Drum-Rio Oso Sub-area*

Drum-Rio Oso is a sub-area of the Sierra LCR area.

Drum-Rio Oso LCR Sub-area Diagram

Figure 3.3-20 Drum-Rio Oso LCR Sub-area



Drum-Rio Oso LCR Sub-area Load and Resources

The Drum-Rio Oso sub-area does not have a defined load pocket with the limits based upon power flow through the area. Table 3.3-14 provides the forecasted resources in the sub-area. The list of generators within the LCR area are provided in Attachment A.

Table 3.3-14 Drum-Rio Oso LCR Sub-area 2021 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Drum-Rio Oso Sub-area does not have a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	390	390
	MUNI	209	209
	QF	40	40
	Solar	5	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	645	640

Drum-Rio Oso LCR Sub-area Hourly Profiles

The Drum-Rio Oso sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Drum-Rio Oso LCR Sub-area Requirement

Table 3.3-15 identifies the sub-area LCR requirements. The Category P6 LCR requirement is 700 MW including 55 MW of NQC deficiency or 60 MW of at peak deficiency.

Table 3.3-15 Drum-Rio Oso LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Rio Oso #1 230/115 kV Tx	Rio Oso #2 230/115 kV & Palermo #2 230/115 kV Txrs	700 (55 NQC/ 60 Peak)

Effectiveness factors

All units within the Drum-Rio Oso sub-area have the same effectiveness factor.

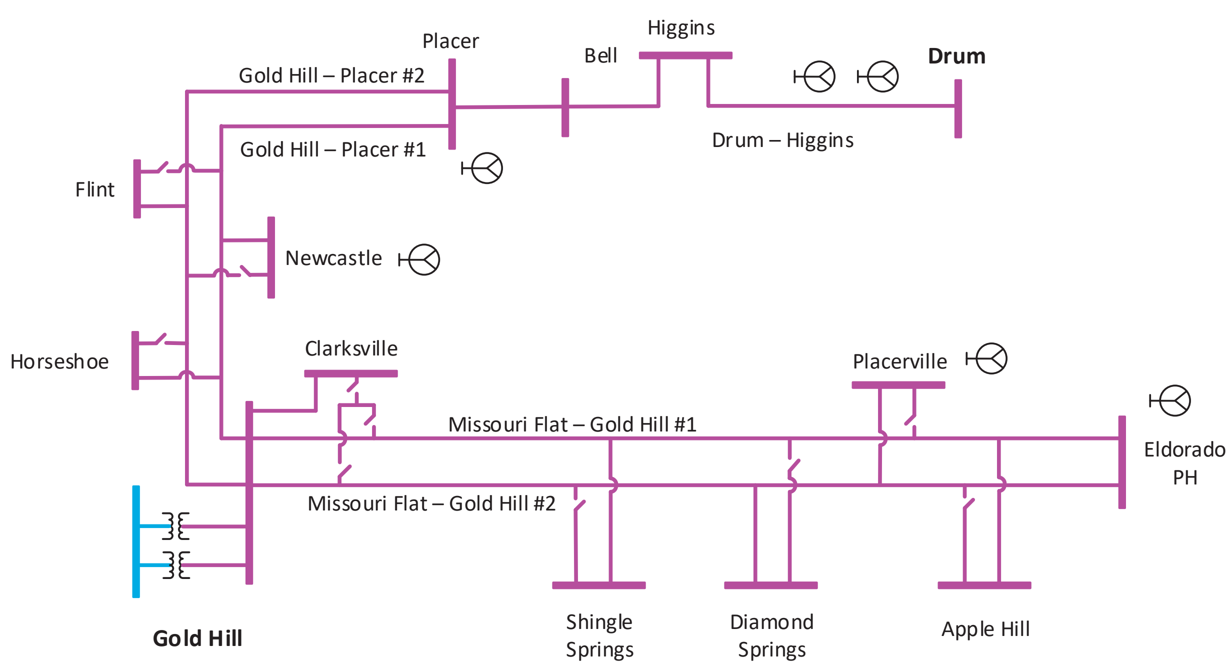
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.5 *Gold Hill-Drum Sub-area*

Gold Hill-Drum is Sub-area of the Sierra LCR Area.

Gold Hill-Drum LCR Sub-area Diagram

Figure 3.3-21 Gold Hill-Drum LCR Sub-area



Gold Hill-Drum LCR Sub-area Load and Resources

Table 3.3-16 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-16 Gold Hill-Drum LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	502	Market and Net Seller	85	85
AAEE	-2	MUNI	42	42
Behind the meter DG	0	QF	0	0
Net Load	499	Solar	0	0
Transmission Losses	9	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	508	Total	127	127

Gold Hill-Drum LCR Sub-area Hourly Profiles

Figure 3.3-22 illustrates the forecast 2021 profile for the peak day for the Gold Hill-Drum sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-23 illustrates the forecast 2021 hourly profile for Gold Hill-Drum sub-area with the Category P6 load serving capability without local gas resources.

Figure 3.3-22 Gold Hill-Drum LCR Sub-area 2021 Peak Day Forecast Profiles

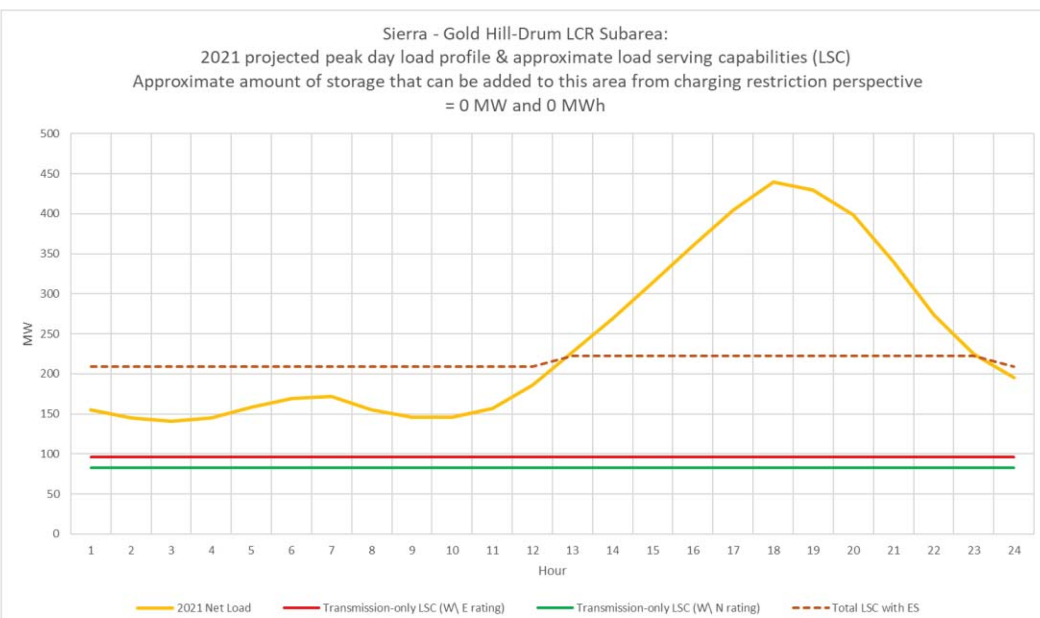
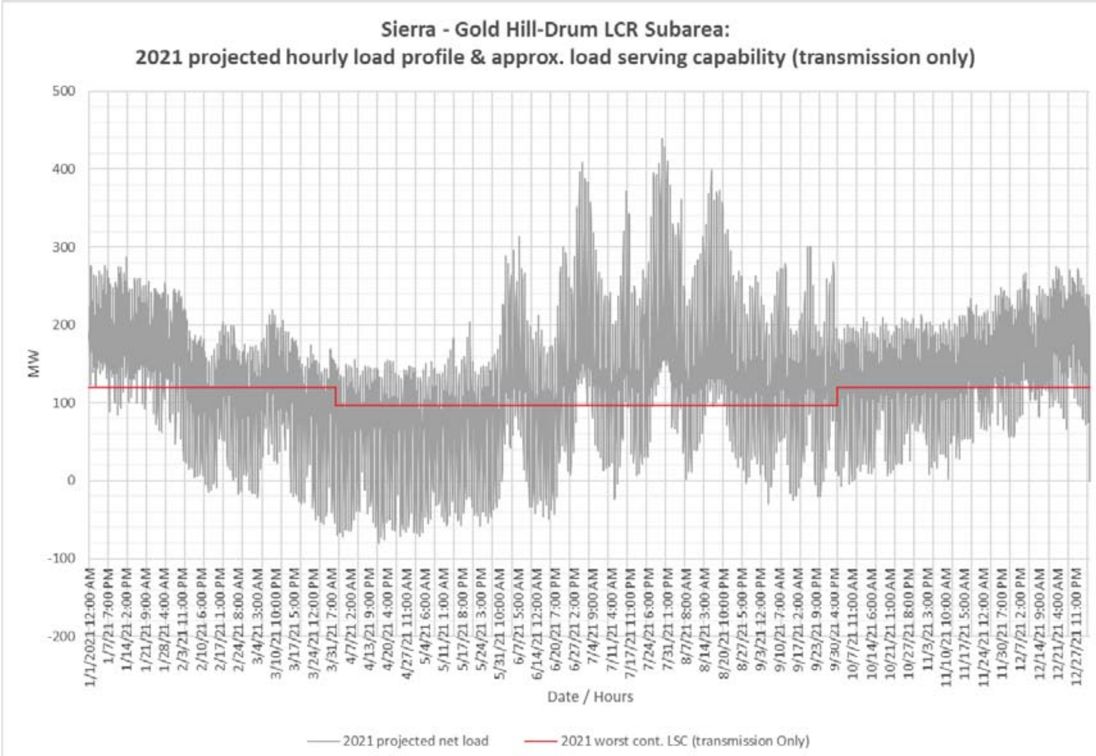


Figure 3.3-23 Gold Hill-Drum LCR Sub-area 2021 Forecast Hourly Profiles



Gold Hill-Drum LCR Sub-area Requirement

Table 3.3-17 identifies the sub-area LCR requirements. The Category P6 LCR requirement is 416 MW including 289 MW of NQC and peak deficiency .

Table 3.3-17 Gold Hill-Drum LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Drum – Higgins 115 kV	Gold Hill 230/115 kV #1 and Gold Hill 230/115 kV #2 Txrs	416 (289)

Effectiveness factors:

All units within the Gold Hill-Drum Sub-area have the same effectiveness factor.

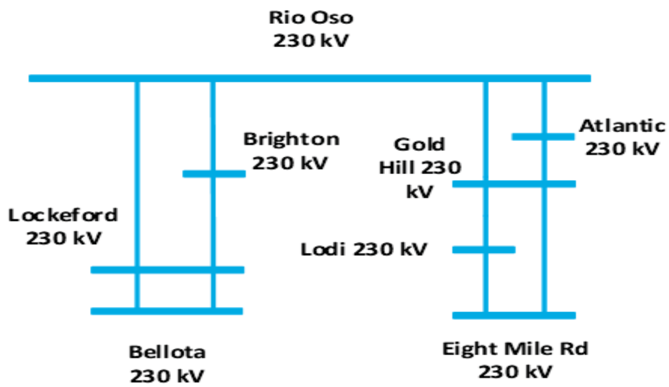
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 and 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.6 *South of Rio Oso Sub-area*

South of Rio Oso is Sub-area of the Sierra LCR Area.

South of Rio Oso LCR Sub-area Diagram

Figure 3.3-24 South of Rio Oso LCR Sub-area



South of Rio Oso LCR Sub-area Load and Resources

The South of Rio Oso sub-area does not have a defined load pocket with the limits based upon power flow through the area. Table 3.3-18 provides the forecasted resources in the sub-area. The list of generators within the LCR area are provided in Attachment A.

Table 3.3-18 South of Rio Oso LCR Sub-area 2021 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The South of Rio Oso Sub-area does not have a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	122	122
	MUNI	621	621
	QF	0	0
	Solar	0	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	743	743

South of Rio Oso LCR Sub-area Hourly Profiles

The South of Rio Oso sub-area does not have a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

South of Rio Oso LCR Sub-area Requirement

Table 3.3-19 identifies the sub-area LCR requirements. The LCR requirement for Category P6 is 665 MW.

Table 3.3-19 South of Rio Oso LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P6	Rio Oso – Atlantic 230 kV	Rio Oso – Gold Hill 230 kV Rio Oso – Brighton 230 kV	665

Effectiveness factors:

Effective factors for generators in the South of Rio Oso LCR sub-area are in Attachment B table titled Rio Oso.

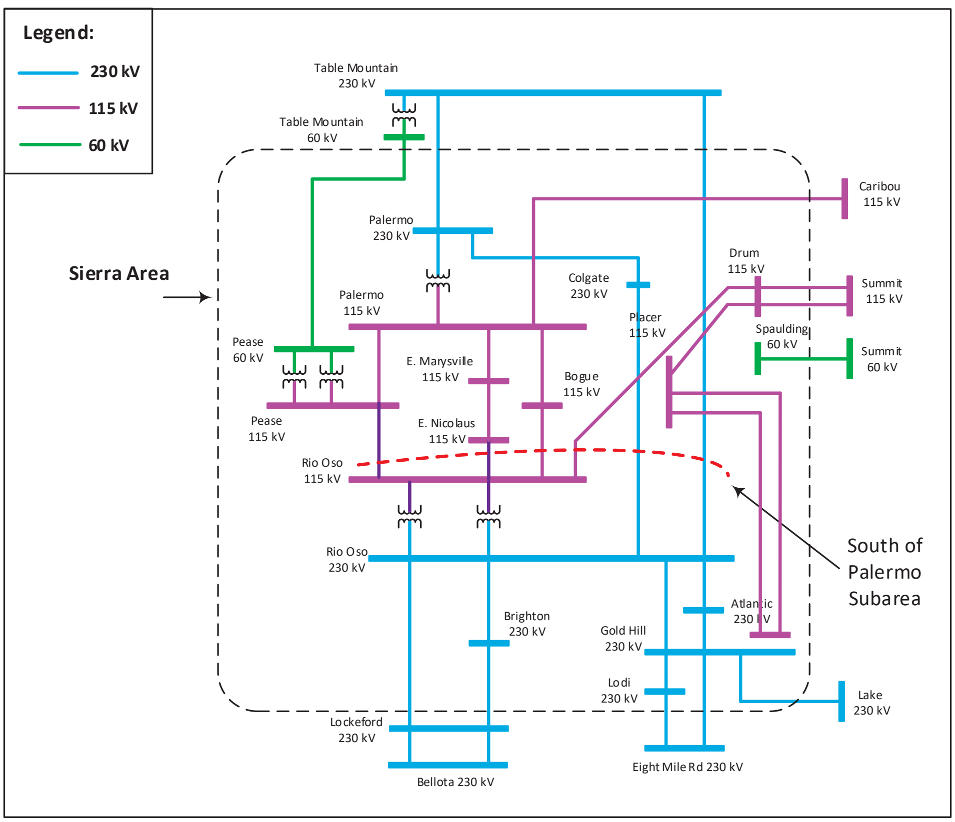
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.7 *South of Palermo Sub-area*

South of Palermo is a Sub-area of the Sierra LCR Area.

South of Palermo LCR Sub-area Diagram

Figure 3.3-25 South of Palermo LCR Sub-area



South of Palermo LCR Sub-area Load and Resources

The South of Palermo sub-area does not have a defined load pocket with the limits based upon power flow through the area. Table 3.3-20 provides the forecasted resources in the sub-area. The list of generators within the LCR area are provided in Attachment A.

Table 3.3-20 South of Palermo LCR Sub-area 2021 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The South of Palermo Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	751	751
	MUNI	666	666
	QF	1	1
	Solar	5	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	1423	1418

South of Palermo LCR Sub-area Hourly Profiles

The South of Palermo sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

South of Palermo LCR Sub-area Requirement

Table 3.3-21 identifies the sub-area requirements. The LCR requirement for Category P6 is 1587 MW including 164 MW of NQC deficiency or 169 MW of at peak deficiency.

Table 3.3-21 South of Palermo LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P6	Pease-Rio Oso 115 kV	Table Mountain-Rio Oso 230 kV Colgate-Rio Oso 230 kV	1587 (164 NQC/ 169 Peak)

Effectiveness factors:

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

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

3.3.3.8 *Sierra Area Overall*

Sierra LCR Area Hourly Profiles

The Sierra LCR Area limits are based upon power flow through the area. As such, no load profile is provided for the area.

Sierra LCR Area Requirement

Table 3.3-22 identifies the area requirements. The LCR requirement for Category P6 is 1821 MW.

Table 3.3-22 Sierra LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P6	Table Mountain – Pease 60 kV	Table Mountain – Palermo 230 kV Table Mountain – Rio Oso 230 kV	1821

Effectiveness factors:

Effective factors for generators in the Sierra Overall LCR area are in Attachment B table titled Sierra Overall.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 and 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

The load forecast went up by 3 MW. The total LCR need has increased by 41 MW and the total existing capacity required has also increase by 57 MW mostly due to changes to the LCR criteria resulting in the addition of Gold Hill – Drum sub-area.

3.3.4 Stockton Area

The LCR requirement for the Stockton Area is driven by the sum of the requirements for the Tesla-Bellota and Lockeford sub-areas.

3.3.4.1 *Area Definition*

Tesla-Bellota Sub-Area Definition

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

Bellota 230/115 kV Transformer #1

Bellota 230/115 kV Transformer #2

Tesla-Tracy 115 kV Line

Tesla-Salado 115 kV Line

Tesla-Salado-Manteca 115 kV line

Tesla-Schulte #1 115 kV Line

Tesla-Schulte #2 115kV line

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

Bellota 230 kV is out Bellota 115 kV is in

Bellota 230 kV is out Bellota 115 kV is in

Tesla is out Tracy is in

Tesla is out Salado is in

Tesla is out Salado and Manteca are in

Tesla is out Schulte is in

Tesla is out Schulte is in

Lockeford Sub-Area Definition

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

Lockeford-Industrial 60 kV line

Lockeford-Lodi #1 60 kV line

Lockeford-Lodi #2 60 kV line

Lockeford-Lodi #3 60 kV line

The substations that delineate the Lockeford Sub-area are:

Lockeford is out Industrial is in

Lockeford is out Lodi is in

Lockeford is out Lodi is in

Lockeford is out Lodi is in

Stockton LCR Area Diagram

The Stockton LCR Area is comprised of the individual noncontiguous Sub-areas with diagrams provided for each of the Sub-areas below.

Stockton LCR Area Load and Resources

Table 3.3-23 provides the forecast load and resources in the area. The list of generators within the LCR area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 19:10 PM.

At the local area peak time the estimated, ISO metered, solar output is 2.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-23 Stockton LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1095	Market and Net Seller	445	445
AAEE	-4	MUNI	139	139
Behind the meter DG	0	QF	0	0
Net Load	1091	Solar	12	0
Transmission Losses	22	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	1113	Total	596	584

Stockton LCR Area Hourly Profiles

The Stockton LCR area is comprised of the individual noncontiguous sub-areas with profiles provided for each of the sub-areas below.

Approved transmission projects modeled

Weber-Stockton “A” #1 and #2 60 kV Reconductoring

Ripon 115 kV line

3.3.4.2 *Weber Sub-area*

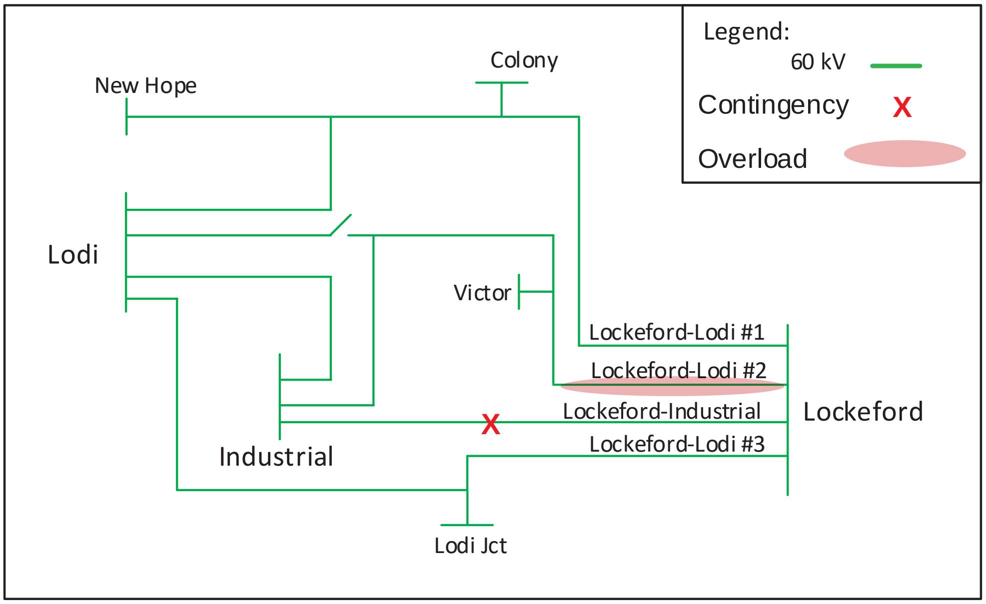
Weber sub-area has been eliminated due to change in LCR criteria.

3.3.4.3 *Lockeford Sub-area*

Lockeford is a sub-area of the Stockton LCR area.

Lockeford LCR Sub-area Diagram

Figure 3.3-26 Lockeford LCR Sub-area



Lockeford LCR Sub-area Load and Resources

Table 3.3-24 provides the forecasted load and resources. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-24 Lockeford LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	194	Market	0	0
AAEE	-1	MUNI	24	24
Behind the meter DG	0	QF	0	0
Net Load	193	Solar	0	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	194	Total	24	24

Lockeford LCR Sub-area Hourly Profiles

Figure 3.3-27 illustrates the forecast 2021 profile for the peak day for the Lockeford sub-area with the Category P3 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-28 illustrates the forecast 2021 hourly profile for Lockeford sub-area with the Category P3 load serving capability without local gas resources.

Figure 3.3-27 Lockeford LCR Sub-area 2021 Peak Day Forecast Profiles

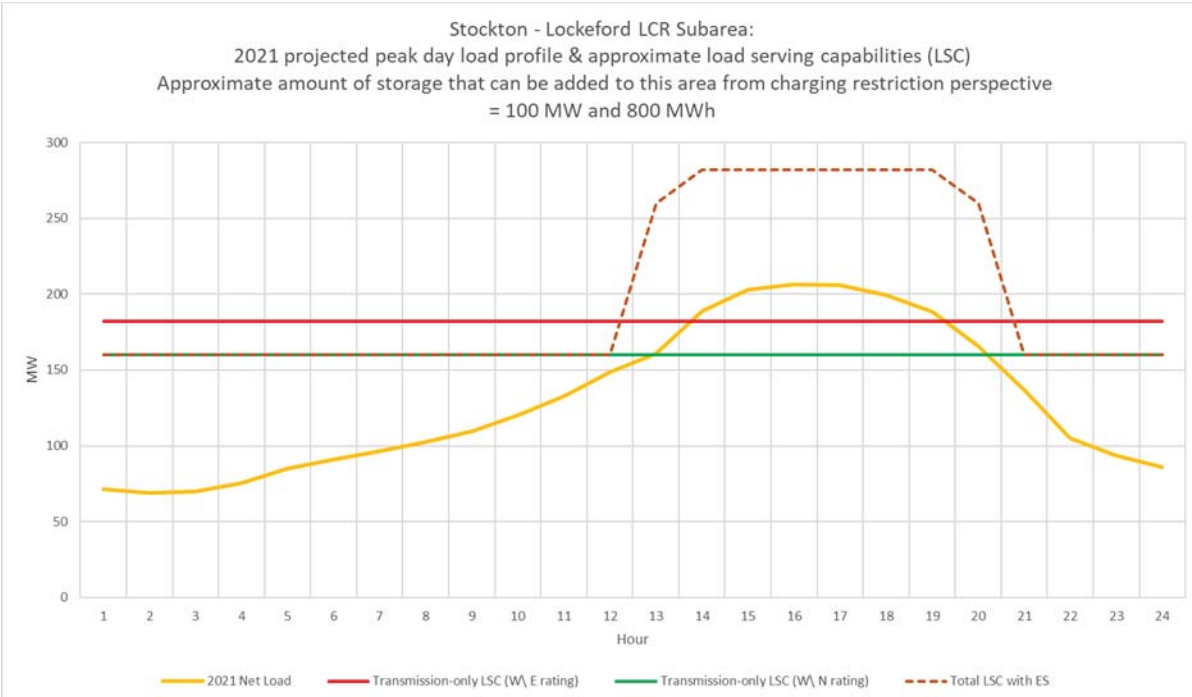
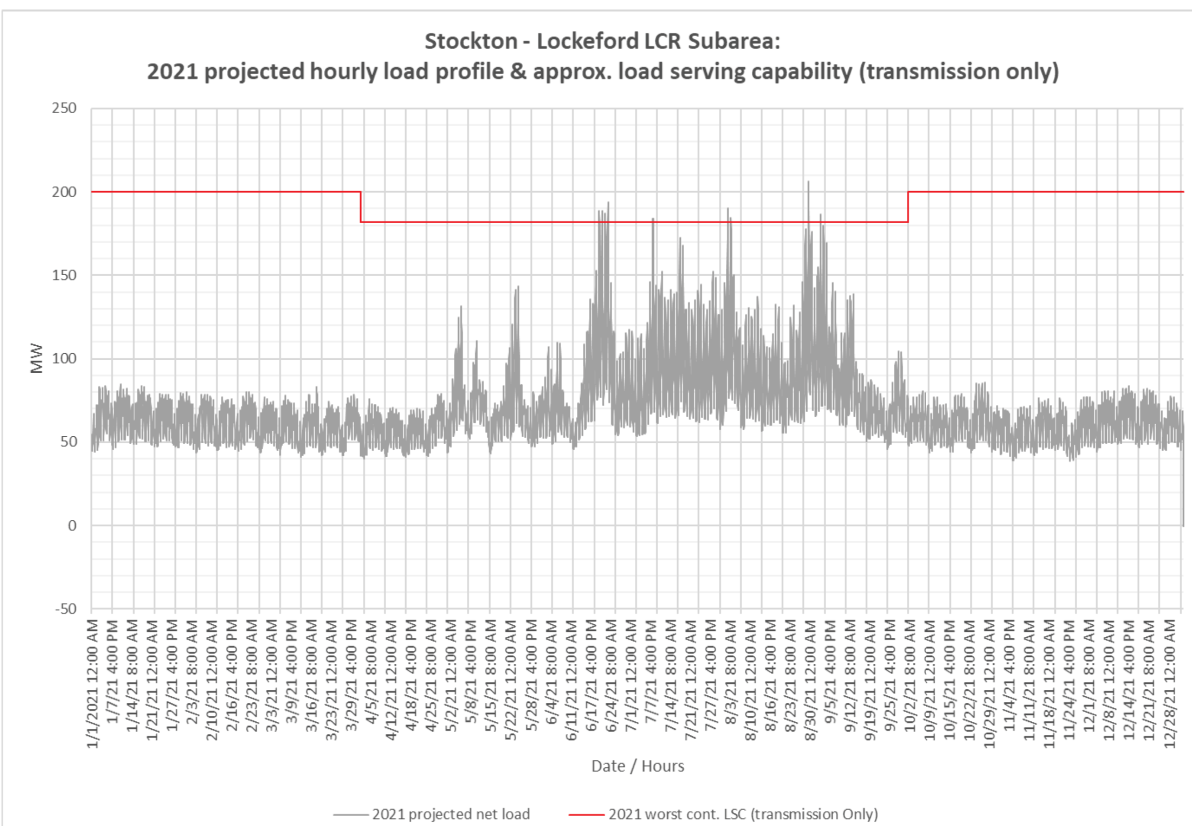


Figure 3.3-28 Lockeford LCR Sub-area 2021 Forecast Hourly Profiles



Lockeford LCR Sub-area Requirement

Table 3.3-25 identifies the sub-area requirements. The LCR requirement for Category P3 contingency is 36 MW including 12 MW of NQC and at peak deficiency.

Table 3.3-25 Lockeford LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P3	Lockeford-Lodi #2 60 kV	Lockeford-Industrial 60 kV & Lodi CT	36 (12)

Effectiveness factors:

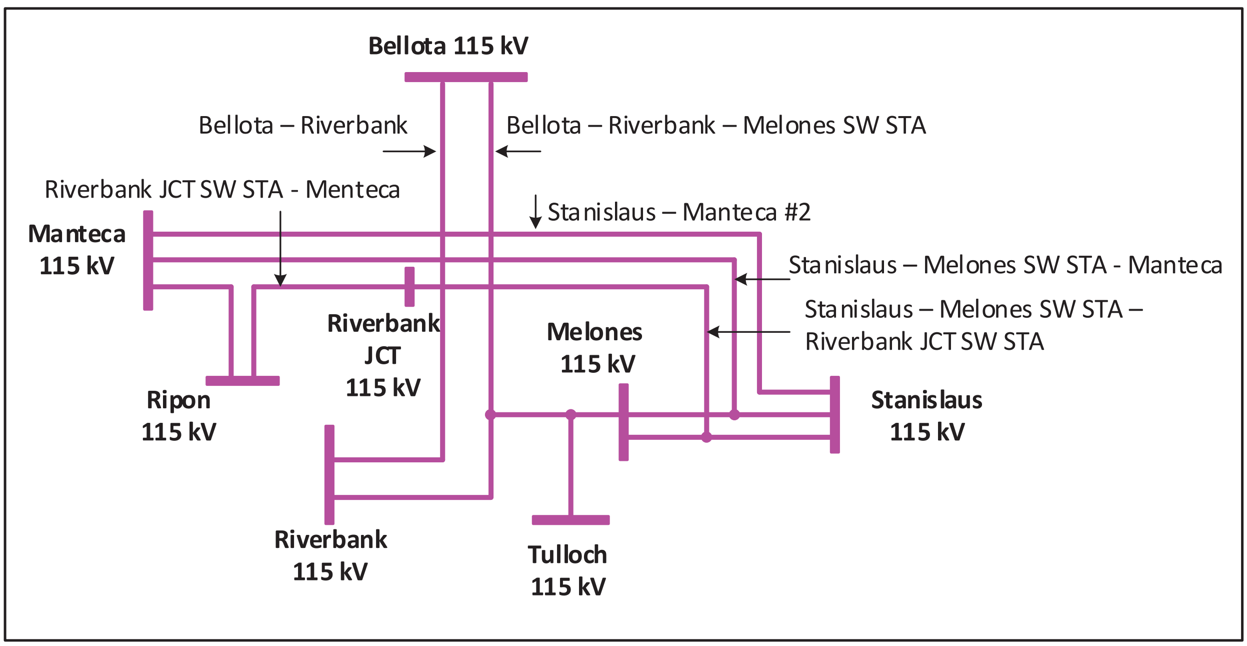
All units within this sub-area are needed therefore no effectiveness factor is required.

3.3.4.4 ***Stanislaus Sub-area***

Stanislaus is a sub-area within the Tesla – Bellota sub-area of the Stockton LCR area.

Stanislaus LCR Sub-area Diagram

Figure 3.3-29 Stanislaus LCR Sub-area



Stanislaus LCR Sub-area Load and Resources

The Stanislaus sub-area does not has a defined load pocket with the limits based upon power flow through the area. Table 3.3-26 provides the forecasted resources in the sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-26 Stanislaus LCR Sub-area 2021 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Stanislaus Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	117	117
	MUNI	94	94
	QF	0	0
	Solar	0	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	211	211

Stanislaus LCR Sub-area Hourly Profiles

The Stanislaus sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Stanislaus LCR Sub-area Requirement

Table 3.3-27 identifies the sub-area requirements. The LCR requirement for Category P3 contingency is 205 MW.

Table 3.3-27 Stanislaus LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P3	Ripon – Manteca 115 kV	Bellota-Riverbank-Melones 115 kV and Stanislaus PH	205

Effectiveness factors:

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

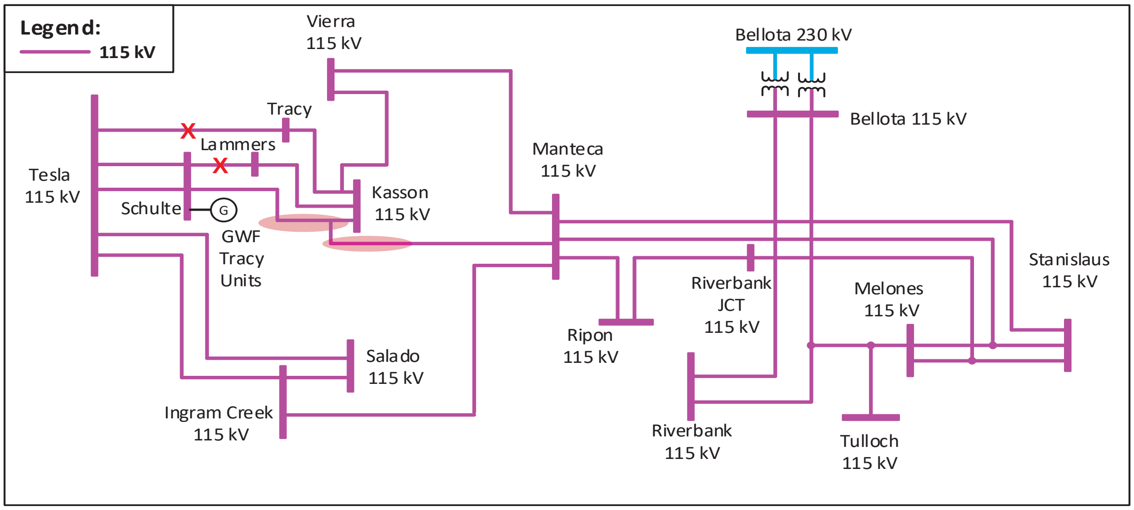
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7410 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.4.5 *Tesla-Bellota Sub-area*

Tesla-Bellota is a Sub-area of the Stockton LCR Area.

Tesla-Bellota LCR Sub-area Diagram

Figure 3.3-30 Tesla-Bellota LCR Sub-area



Tesla Bellota LCR Sub-area Load and Resources

Table 3.3-28 provides the forecasted load and resources. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-28 Tesla-Bellota LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	901	Market and Net Seller	445	445
AAEE	-3	MUNI	116	116
Behind the meter DG	0	QF	0	0
Net Load	898	Solar	12	0
Transmission Losses	21	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	919	Total	573	561

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

Tesla-Bellota LCR Sub-area Hourly Profiles

Figure 3.3-31 illustrates the forecast 2021 profile for the peak day for the Tesla-Bellota sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-32 illustrates the forecast 2021 hourly profile for Tesla-Bellota sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-31 Tesla-Bellota LCR Sub-area 2021 Peak Day Forecast Profiles

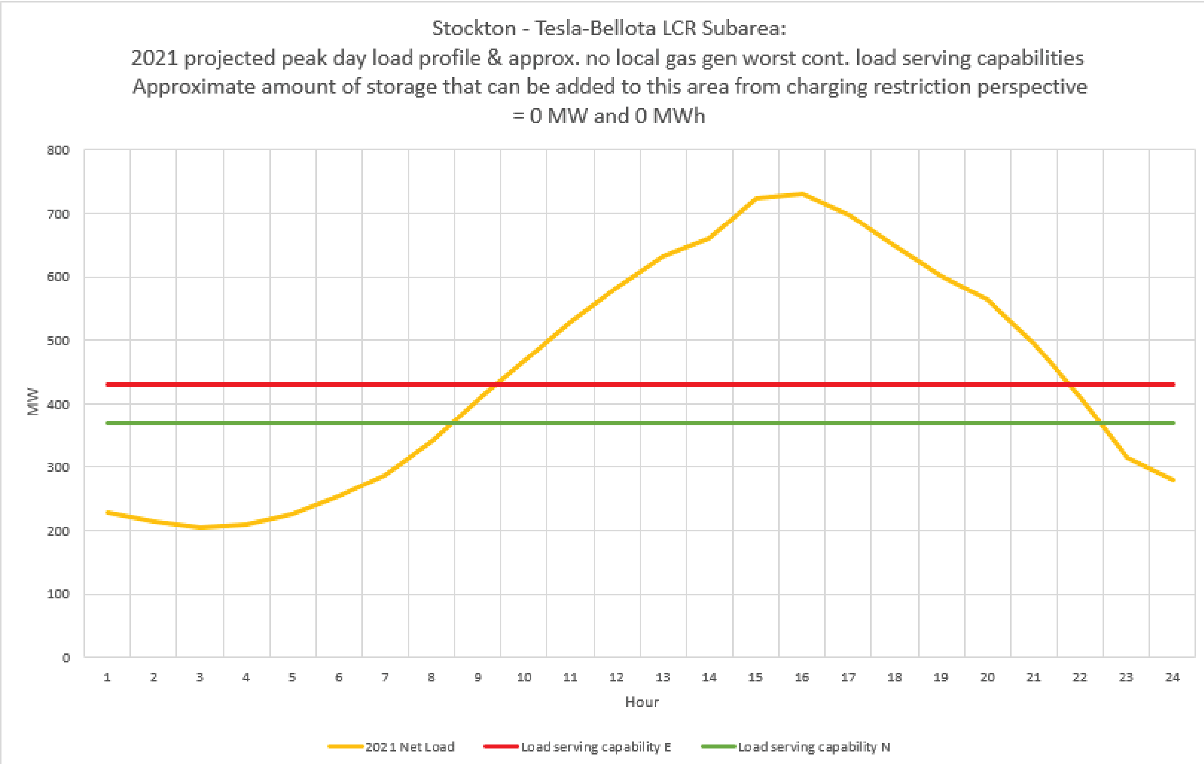
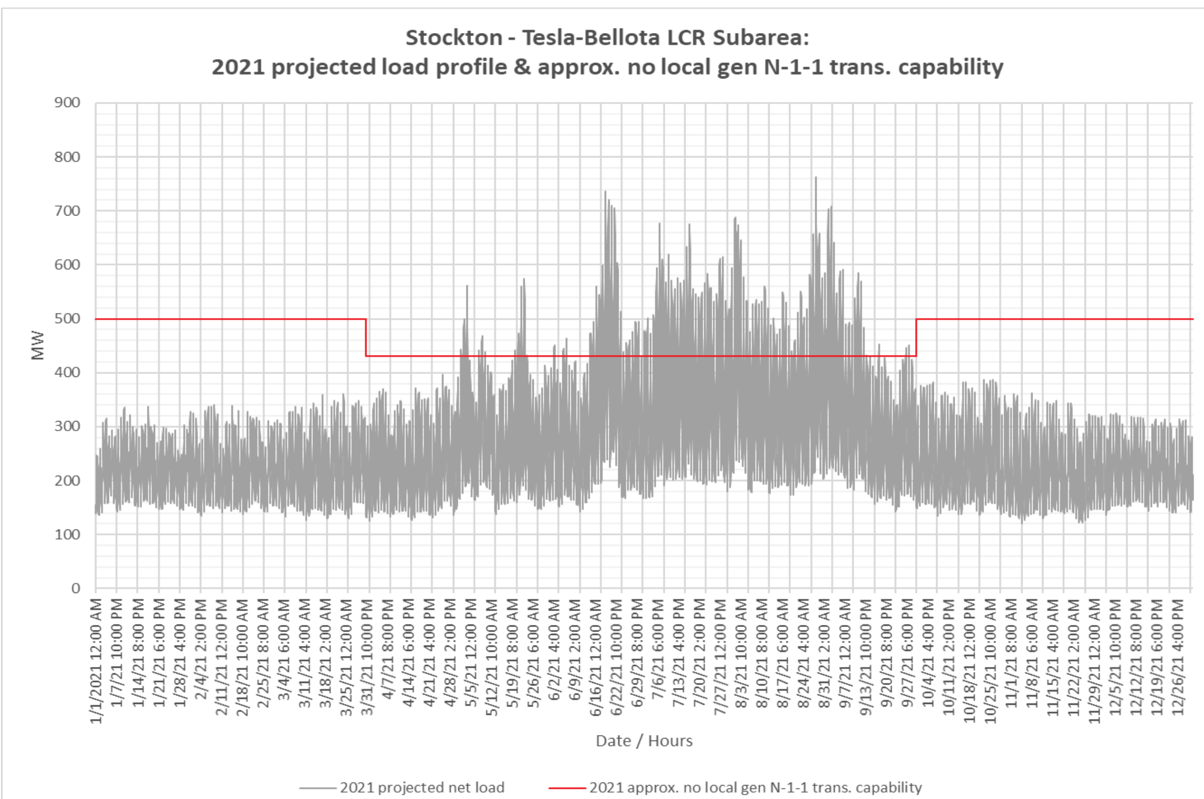


Figure 3.3-32 Tesla-Bellota LCR Sub-area 2021 Forecast Hourly Profiles



Tesla-Bellota LCR Sub-area Requirement

Table 3.3-29 identifies the sub-area requirements. The LCR requirement for Category P6 contingency is 1219 MW including a 646 MW NQC and 658 MW at peak deficiency.

Table 3.3-29 Tesla-Bellota LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P6	Schulte-Kasson-Manteca 115 kV	Schulte – Lammers 115 kV & Tesla – Tracy 115 kV	909 (646 NQC/ 658 Peak)
2021	First limit	P2-4	Stanislaus – Melones – Riverbank Jct 115 kV	Tesla 115 kV bus	960 (387 NQC/ 399 Peak)
Total LCR Need for Tesla – Bellota Sub-area in 2021					1219 (646 NQC/ 658 Peak)

Effectiveness factors:

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7410 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.4.6 *Stockton Overall*

Stockton LCR Area Overall Requirement

The requirement for this area is driven by the sum of requirements for the Tesla-Bellota and Lockeford sub-areas. Table 3.3-30 identifies the area requirements. The LCR requirement is 1255 MW with a 658 MW NQC deficiency or 670 MW at peak deficiency.

Table 3.3-30 Stockton LCR Area Overall Requirements

Year	LCR (MW) (Deficiency)
2021	1255 (658 NQC/ 670 Peak)

Changes compared to 2019 LCT study

The load forecast went down by 162 MW due to the elimination of the Weber sub-area else the load trend is up by 74 MW. The total LCR need has increased by 15 MW, however the existing capacity needed has been reduced by 33 MW, both due to change in LCR criteria.

3.3.5 Greater Bay Area

3.3.5.1 *Area Definition:*

The transmission tie lines into the Greater Bay Area are:

Lakeville-Sobrante 230 kV

Ignacio-Sobrante 230 kV

Parkway-Moraga 230 kV

Bahia-Moraga 230 kV

Lambie SW Sta-Vaca Dixon 230 kV

Peabody-Contra Costa P.P. 230 kV

Tesla-Kelso 230 kV

Tesla-Delta Switching Yard 230 kV

Tesla-Pittsburg #1 230 kV

Tesla-Pittsburg #2 230 kV

Tesla-Newark #1 230 kV

Tesla-Newark #2 230 kV

Tesla-Ravenswood 230 kV

Tesla-Metcalf 500 kV

Moss Landing-Metcalf 500 kV

Moss Landing-Metcalf #1 230 kV

Moss Landing-Metcalf #2 230 kV

Oakdale TID-Newark #1 115 kV

Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

Lakeville is out Sobrante is in

Ignacio is out Sobrante is in

Parkway is out Moraga is in

Bahia is out Moraga is in

Lambie SW Sta is in Vaca Dixon is out

Peabody is out Contra Costa P.P. is in

Tesla is out Kelso is in

Tesla is out Delta Switching Yard is in

Tesla is out Pittsburg is in

Tesla is out Pittsburg is in

Tesla is out Newark is in

Tesla is out Newark is in

Tesla is out Ravenswood is in

Tesla is out Metcalf is in

Moss Landing is out Metcalf is in

Moss Landing is out Metcalf is in

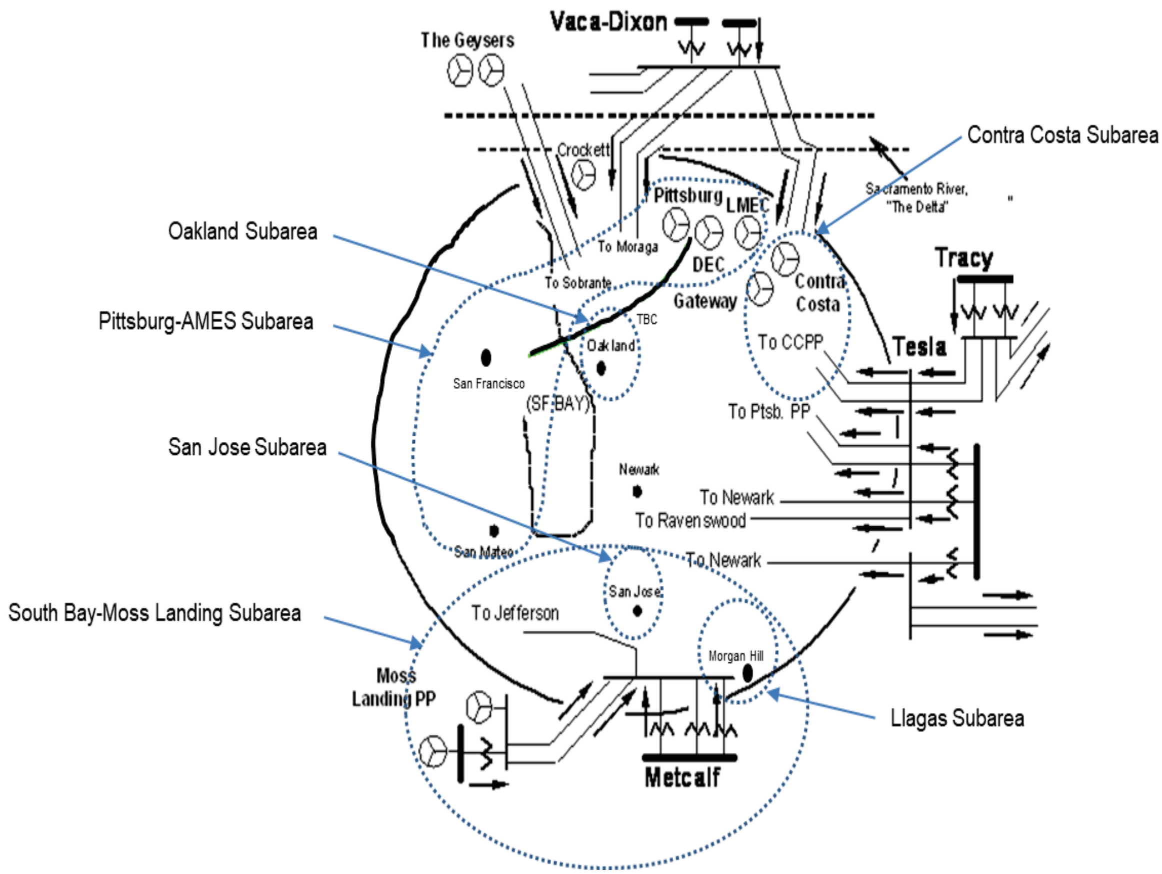
Moss Landing is out Metcalf is in

Oakdale TID is out Newark is in

Oakdale TID is out Newark is in

Greater Bay LCR Area Diagram

Figure 3.3-33 Greater Bay LCR Area



Greater Bay LCR Area Load and Resources

Table 3.3-31 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 17:50 PM.

At the local area peak time the estimated, ISO metered, solar output is 44.00%.

If required, all technology type resources, including solar, are dispatched at NQC.

Table 3.3-31 Greater Bay Area LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	10508	Market, Net Seller, Wind, Battery	6248	6248
AAEE	-57	MUNI	377	377
Behind the meter DG	-179	QF	227	227
Net Load	10272	Solar	8	8
Transmission Losses	244	Existing 20-minute Demand Response	0	0
Pumps	264	Future preferred resource and energy storage	558	558
Load + Losses + Pumps	10780	Total	7418	7418

Approved transmission projects modeled

Morgan Hill Area Reinforcement (revised scope)

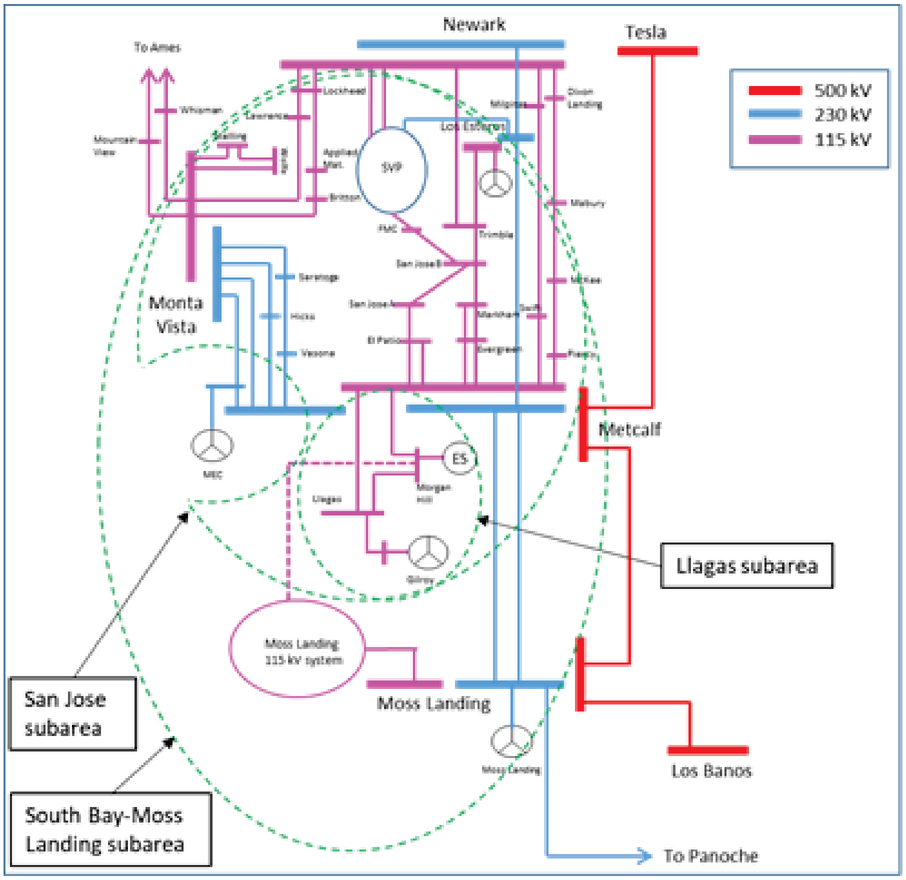
Vaca Dixon-Lakeville 230 kV Corridor Series Compensation

3.3.5.2 *Llagas Sub-area*

Llagas is a Sub-area of the Greater Bay LCR Area.

Llagas LCR Sub-area Diagram

Figure 3.3-34 Llagas LCR Sub-area



Llagas LCR Sub-area Load and Resources

Table 3.3-32 provides the forecasted load and resources. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-32 Llagas LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	207	Market	246	246
AAEE	-2	MUNI	0	0
Behind the meter DG	-6	QF	0	0
Net Load	199	LTPP Preferred Resources	0	0
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	199	Total	246	246

Llagas LCR Sub-area Hourly Profiles

Figure 3.3-35 illustrates the forecast 2021 profile for the peak day for the Llagas LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-36 illustrates the forecast 2021 hourly profile for Llagas LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-35 Llagas LCR Sub-area 2021 Peak Day Forecast Profiles

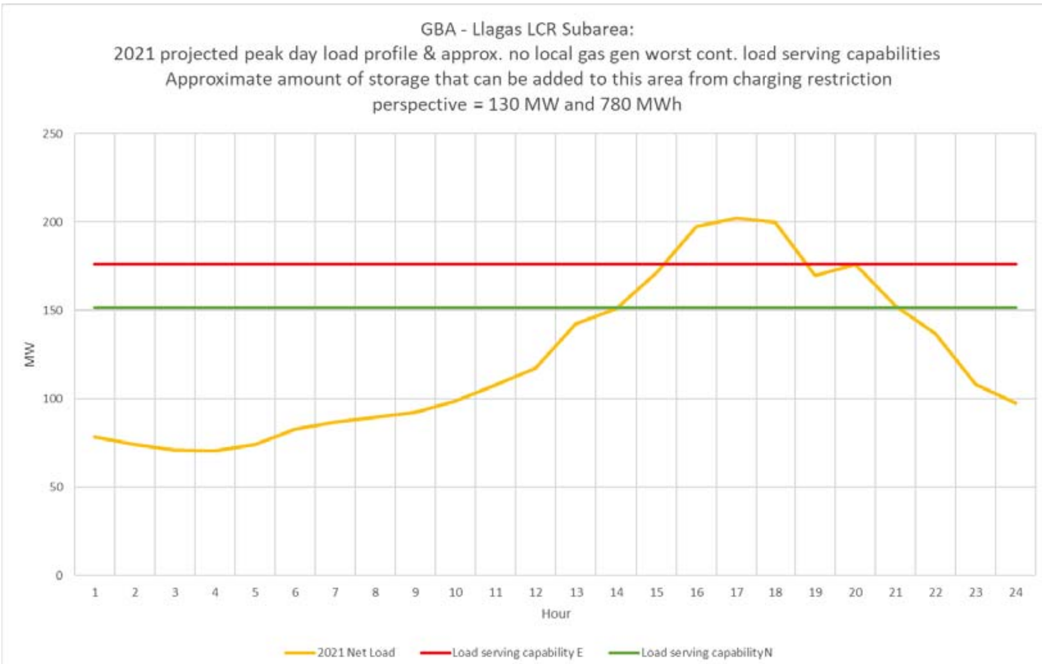
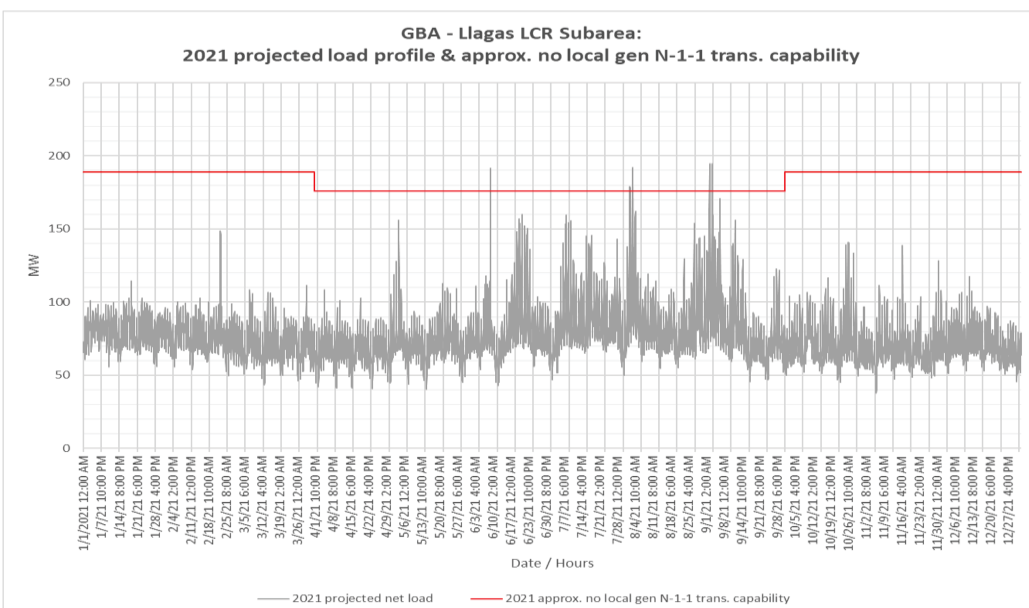


Figure 3.3-36 Llagas LCR Sub-area 2021 Forecast Hourly Profiles



Llagas LCR Sub-area Requirement

Table 3.3-33 identifies the sub-area requirements. The LCR requirement for the worst contingency is 31 MW.

Table 3.3-33 Llagas LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First limit	P6	Metcalf-Llagas 115 kV	Metcalf-Morgan Hill 115 kV & Morgan Hill-Green Valley 115 kV	31

Effectiveness factors:

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

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

3.3.5.3 *San Jose Sub-area*

San Jose is a Sub-area of the Greater Bay LCR Area.

San Jose LCR Sub-area Diagram

The San Jose LCR Sub-area is identified in Figure 3.3-34.

San Jose LCR Sub-area Load and Resources

Table 3.3-34 provides the forecast load and resources in San Jose LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-34 San Jose LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	2531	Market, Net Seller, Battery	575	575
AAEE	-16	MUNI	198	198
Behind the meter DG	-38	QF	0	0
Net Load	2477	LTPP Preferred Resources	75	75
Transmission Losses	66	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	2543	Total	848	848

San Jose LCR Sub-area Hourly Profiles

Figure 3.3-37 illustrates the forecast 2021 profile for the peak day for the San Jose LCR sub-area with the Category P2 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-38 illustrates the forecast 2021 hourly profile for San Jose LCR sub-area with the Category P2 emergency load serving capability without local gas resources.

Figure 3.3-37 San Jose LCR Sub-area 2021 Peak Day Forecast Profiles

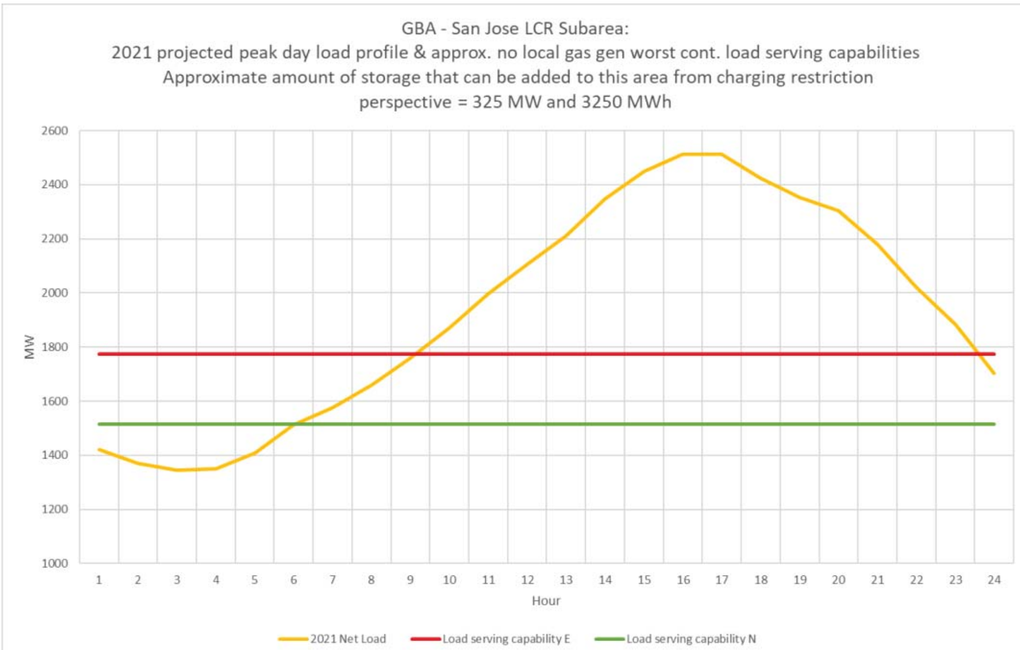
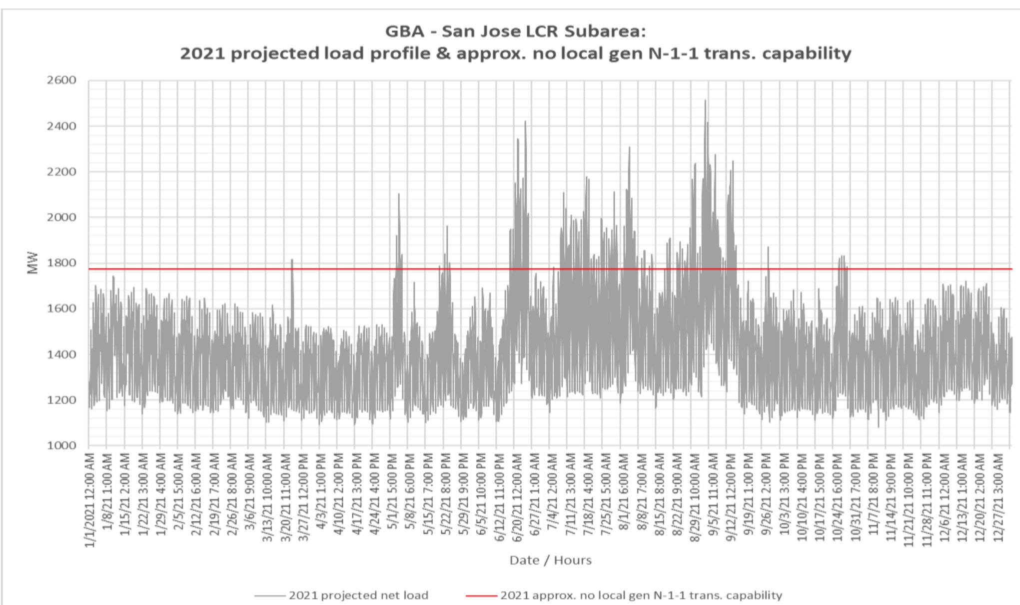


Figure 3.3-38 San Jose LCR Sub-area 2021 Forecast Hourly Profiles



San Jose LCR Sub-area Requirement

Table 3.3-35 identifies the sub-area LCR requirements. The LCR requirement for the worst contingency is 793 MW.

Table 3.3-35 San Jose LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First limit	P2	Metcalf 230/115 kV transformer # 1 or # 3	METCALF 230kV - Section 2D & 2E	793

Effectiveness factors:

Effective factors for generators in the San Jose LCR sub-area are in Attachment B table titled San Jose.

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

3.3.5.4 *South Bay-Moss Landing Sub-area*

South Bay-Moss Landing is a Sub-area of the Greater Bay LCR Area.

South Bay-Moss Landing LCR Sub-area Diagram

The South Bay-Moss Landing LCR sub-area is identified in Figure 3.3-34.

South Bay-Moss Landing LCR Sub-area Load and Resources

Table 3.3-36 provides the forecast load and resources in South Bay-Moss Landing LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-36 South Bay-Moss Landing LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4139	Market, Net Seller, Battery	2165	2165
AAEE	-26	MUNI	198	198
Behind the meter DG	-76	QF	0	0
Net Load	4037	LTPP Preferred Resources	558	558
Transmission Losses	108	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	4145	Total	2921	2921

South Bay-Moss Landing LCR Sub-area Hourly Profiles

Figure 3.3-39 illustrates the forecasted 2021 profile for the peak day for the South Bay-Moss Landing LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.3-40 illustrates the forecast 2021 hourly profile for South Bay-Moss Landing LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-39 South Bay-Moss Landing LCR Sub-area 2021 Peak Day Forecast Profiles

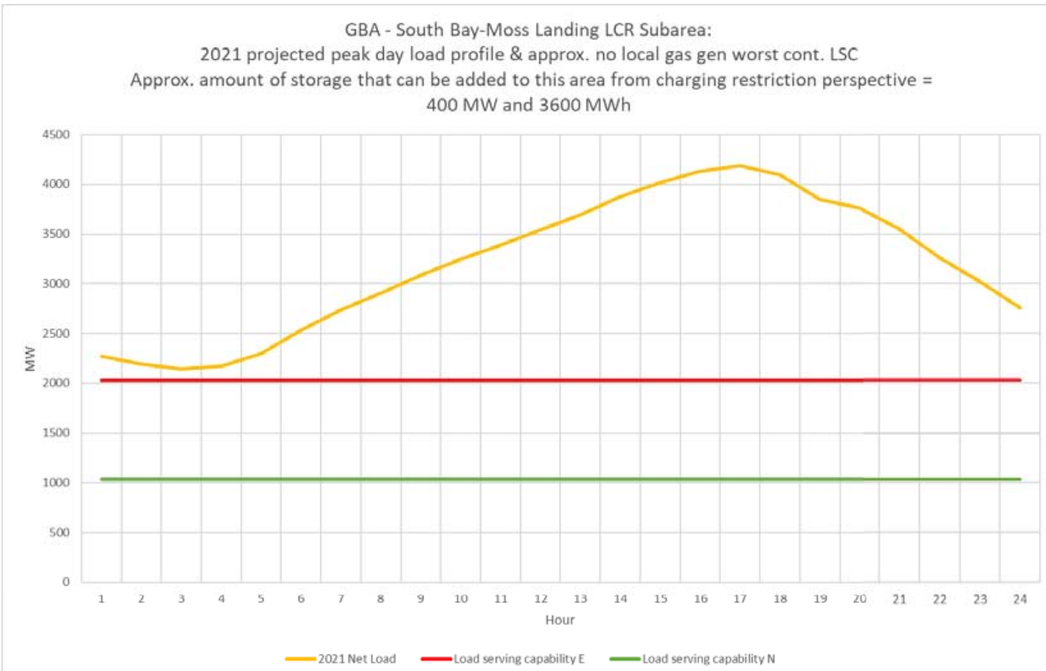
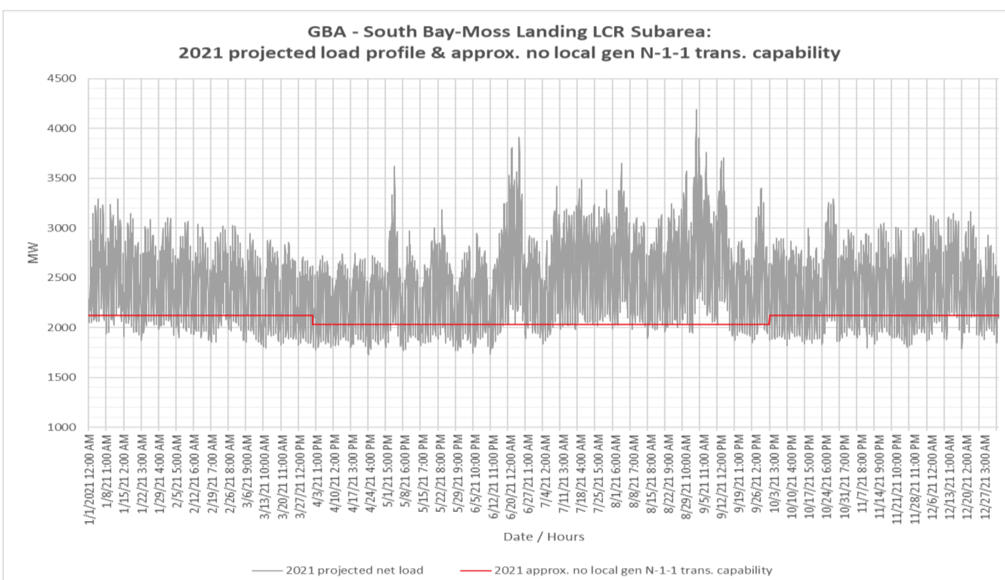


Figure 3.3-40 South Bay-Moss Landing LCR Sub-area 2021 Forecast Hourly Profiles



South Bay-Moss Landing LCR Sub- Requirement

Table 3.3-37 identifies the sub-area LCR requirements. The LCR Requirement for the worst contingency is 1833 MW.

Table 3.3-37 South Bay-Moss Landing LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First Limit	P6	Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	1833

Effectiveness factors:

Effective factors for generators in the South Bay-Moss Landing LCR sub-area are in Attachment B table titled South Bay-Moss Landing.

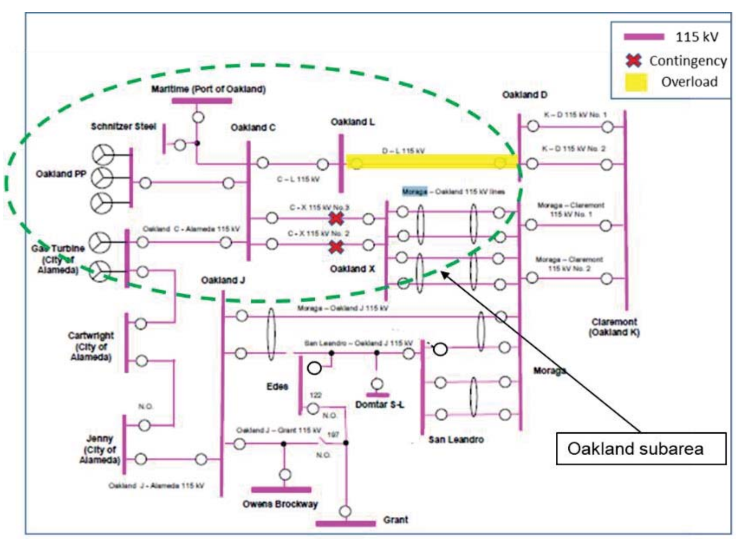
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.5 *Oakland Sub-area*

Oakland is a Sub-area of the Greater Bay LCR Area.

Oakland LCR Sub-area Diagram

Figure 3.3-41 Oakland LCR Sub-area



Oakland LCR Sub-area Load and Resources

Table 3.3-38 provides the forecast load and resources in Oakland LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-38 Oakland LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	221	Market	110	110
AAEE	-1	MUNI	48	48
Behind the meter DG	-2	QF	0	0
Net Load	218	LTPP Preferred Resources	0	0
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	218	Total	158	158

Oakland LCR Sub-area Hourly Profiles

Figure 3.3-42 illustrates the forecast 2021 profile for the peak day for the Oakland LCR sub-area with the Category P2 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-43 illustrates the forecast 2021 hourly profile for Oakland LCR sub-area with the Category P2 emergency load serving capability without local gas resources.

Figure 3.3-42 Oakland LCR Sub-area 2021 Peak Day Forecast Profiles

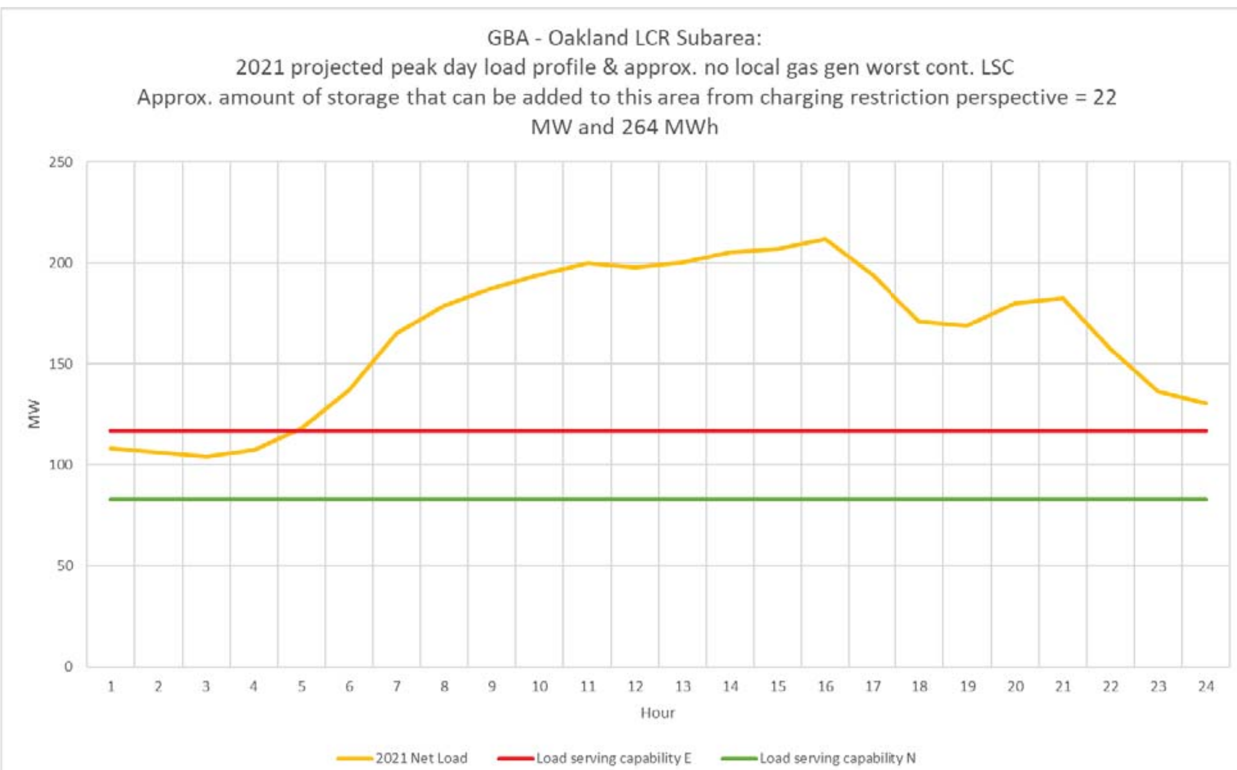
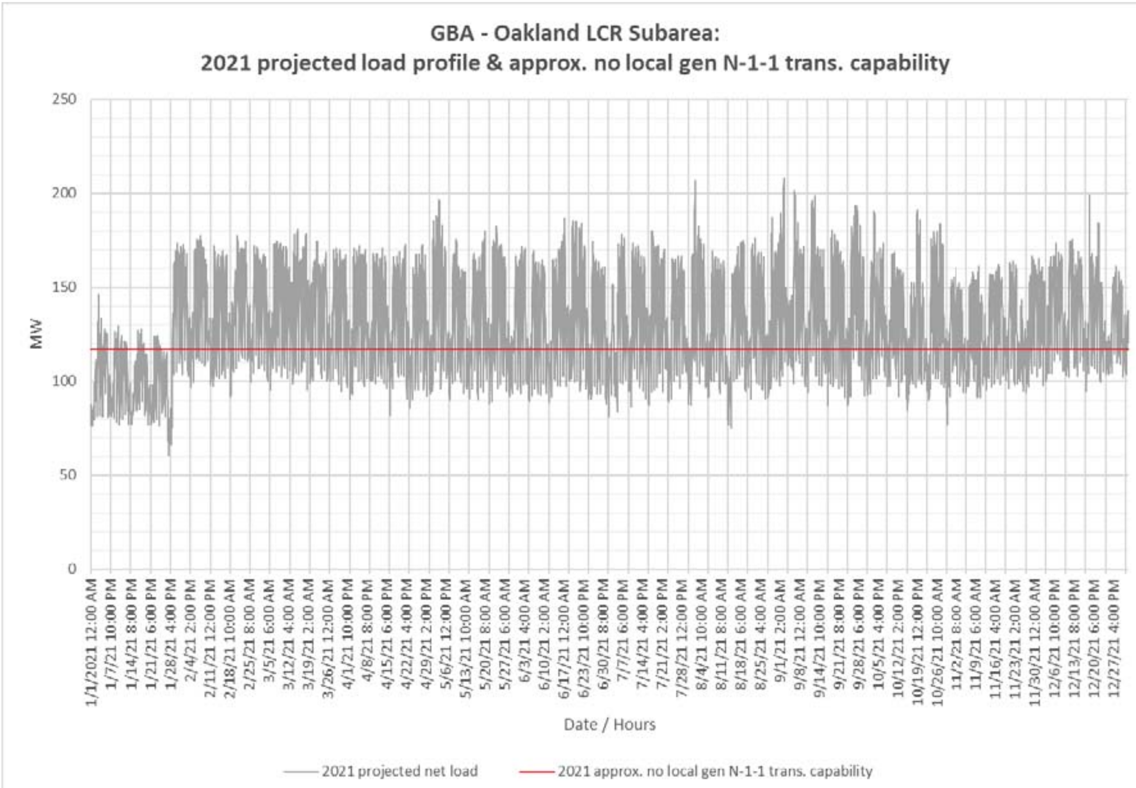


Figure 3.3-43 Oakland LCR Sub-area 2021 Forecast Hourly Profiles



Oakland LCR Sub-area Requirement

Table 3.3-39 identifies the sub-area requirements. The LCR Requirement for the worst contingency is 99 MW.

Table 3.3-39 Oakland LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First limit	P2	Moraga-Oakland X #3 or #4 115 kV line	Moraga 115kV - Section 1D & 2D	99

Effectiveness factors:

All units within the Oakland Sub-area have the same effectiveness factor.

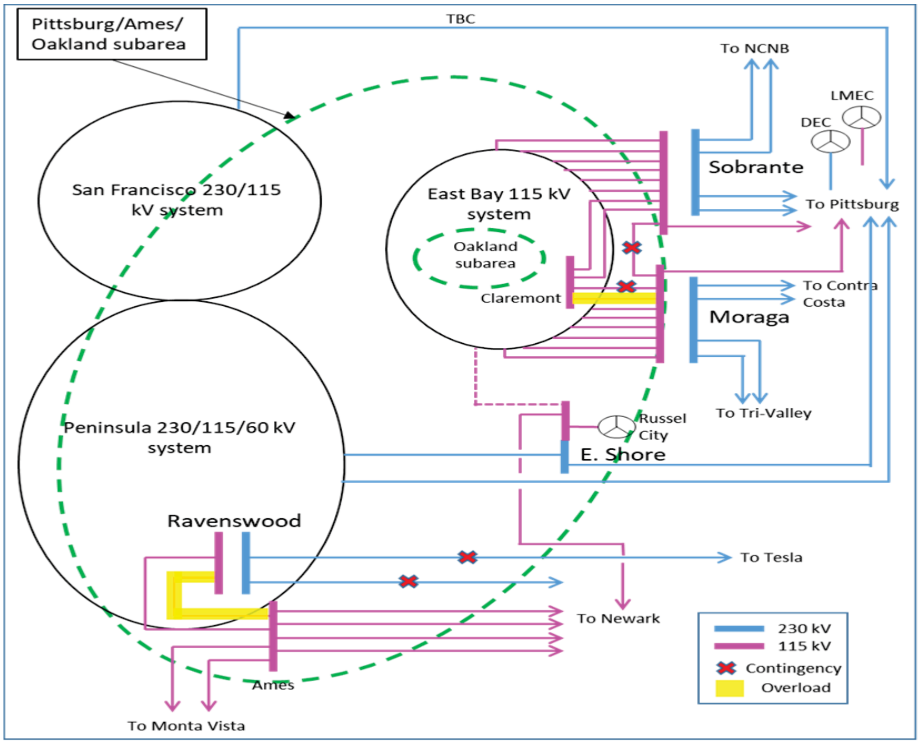
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.6 *Ames-Pittsburg-Oakland Sub-areas Combined*

Ames-Pittsburg-Oakland is a Sub-area of the Greater Bay LCR Area.

Ames-Pittsburg-Oakland LCR Sub-area Diagram

Figure 3.3-44 Ames-Pittsburg-Oakland LCR Sub-area



Ames-Pittsburg-Oakland LCR Sub-area Load and Resources

Table 3.3-40 provides the forecast load and resources in Ames-Pittsburg-Oakland LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-40 Ames-Pittsburg-Oakland LCR Sub-area 2021 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Ames-Pittsburg-Oakland Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller	2152	2152
	MUNI	48	48
	QF	225	225
	Solar	5	5
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	2430	2430

Ames-Pittsburg-Oakland LCR Sub-area Hourly Profiles

The Ames-Pittsburg-Oakland sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Ames-Pittsburg-Oakland LCR Sub-area Requirement

Table 3.3-41 identifies the sub-area LCR requirements. The LCR Requirement for the worst contingency is 1614 MW.

Table 3.3-41 Ames-Pittsburg-Oakland LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2020	First limit	P6	Ames-Ravenswood #1 115 kV line	Newark-Ravenswood 230 kV & Tesla-Ravenswood 230 kV	1967
		P2	Moraga-Claremont #2 115 kV line	Moraga 115kV - Section 2D & 2E	

Effectiveness factors:

Effective factors for generators in the Ames-Pittsburg-Oakland LCR sub-area are in Attachment B table titled Ames/Pittsburg/Oakland.

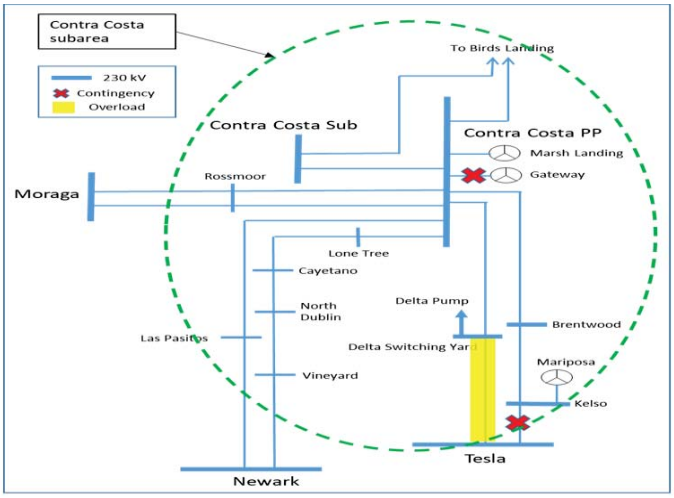
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.7 *Contra Costa Sub-area*

Contra Costa is a Sub-area of the Greater Bay LCR Area.

Contra Costa LCR Sub-area Diagram

Figure 3.3-45 Contra Costa LCR Sub-area



Contra Costa LCR Sub-area Load and Resources

Table 3.3-42 provides the forecast load and resources in Contra Costa LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-42 Contra Costa LCR Sub-area 2021 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Contra Costa Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller, Wind	1669	1669
	MUNI	127	127
	QF	0	0
	Wind	244	244
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	2040	2040

Contra Costa LCR Sub-area Hourly Profiles

The Contra Costa sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Contra Costa LCR Sub-area Requirement

Table 3.3-43 identifies the sub-area LCR requirements. The LCR requirement for the worst contingency is 1155 MW.

Table 3.3-43 Contra Costa LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First limit	P3	Delta Switching Yard-Tesla 230 kV	Kelso-Tesla 230 kV line and Gateway unit	1119

Effectiveness factors:

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

3.3.5.8 *Bay Area overall*

Bay Area LCR Area Hourly Profiles

Figure 3.3-46 illustrates the forecast 2021 profile for the peak day for the Bay Area LCR area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-47 illustrates the forecast 2021 hourly profile for Bay Area LCR area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-46 Bay Area LCR Area 2021 Peak Day Forecast Profiles

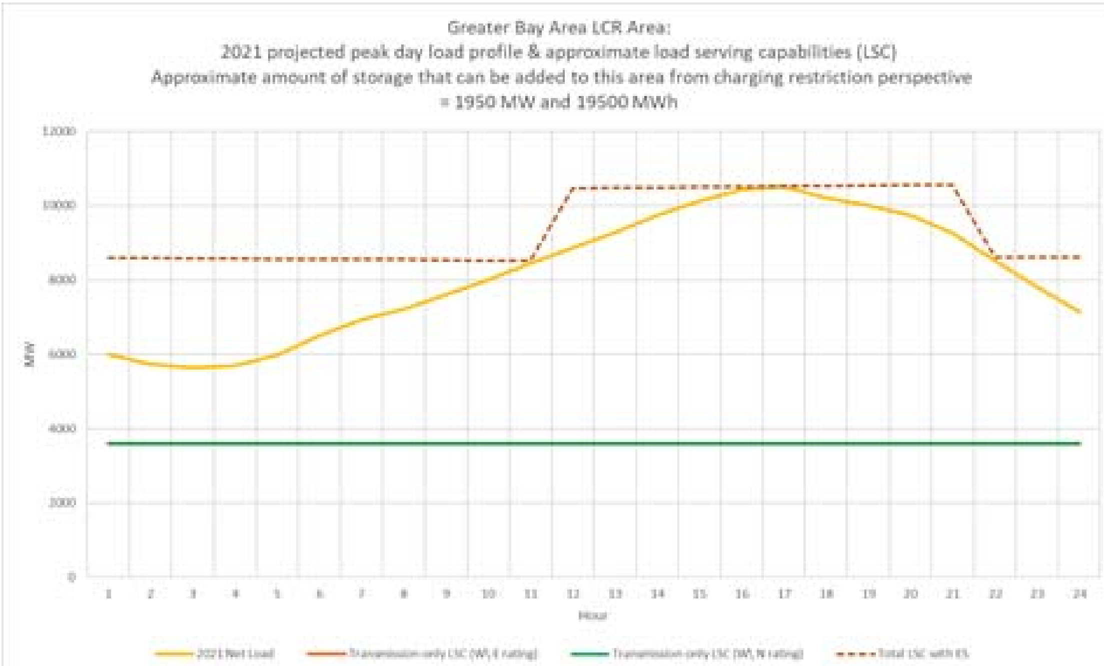
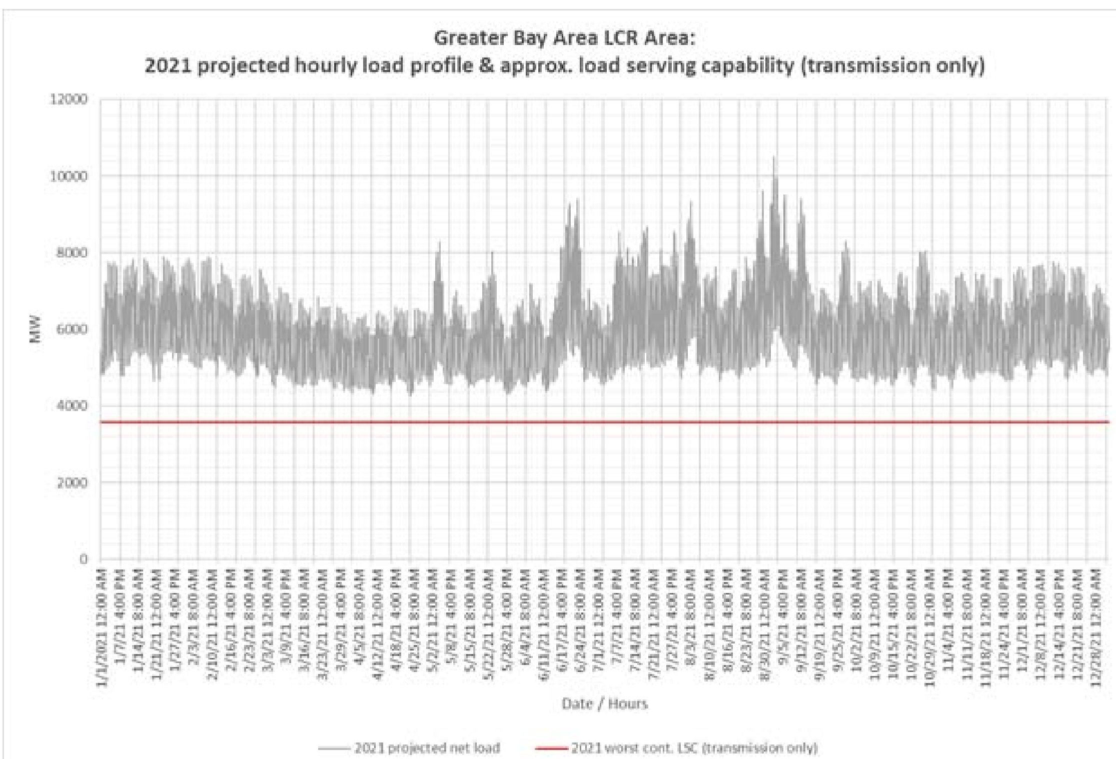


Figure 3.3-47 Bay Area LCR Area 2021 Forecast Hourly Profiles



Greater Bay LCR Area Overall Requirement

Table 3.3-44 identifies the area LCR requirements. The LCR requirement for the worst contingency is 6353 MW.

Table 3.3-44 Bay Area LCR Overall area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First limit	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	6353

Effectiveness factors:

Effective factors for generators in the Greater Bay Area LCR sub-area are in Attachment B table titled Greater Bay Area.

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

Changes compared to 2020 requirements

Compared to 2020 load forecast went up by 292 MW and total LCR need went up by 1803 MW mainly due to LCR criteria change.

3.3.6 Greater Fresno Area

3.3.6.1 *Area Definition:*

The transmission facilities coming into the Greater Fresno area are:

Gates-Mustang #1 230 kV

Gates-Mustang #2 230 kV

Gates #5 230/70 kV Transformer Bank

Mercy Spring 230 /70 Bank # 1

Los Banos #3 230/70 Transformer Bank

Los Banos #4 230/70 Transformer Bank

Warnerville-Wilson 230kV

Melones-North Merced 230 kV line

Panoche-Tranquility #1 230 kV

Panoche-Tranquility #2 230 kV

Panoche #1 230/115 kV Transformer Bank

Panoche #2 230/115 kV Transformer Bank

Corcoran-Smyrna 115kV

Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

Gates is out Mustang is in

Gates is out Mustang is in

Gates 230 is out Gates 70 is in

Mercy Springs 230 is out Mercy Springs 70 is in

Los Banos 230 is out Los Banos 70 is in

Los Banos 230 is out Los Banos 70 is in

Warnerville is out Wilson is in

Melones is out North Merced is in

Panoche is out Tranquility #1 is in

Panoche is out Tranquility #2 is in

Panoche 230 is out Panoche 115 is in

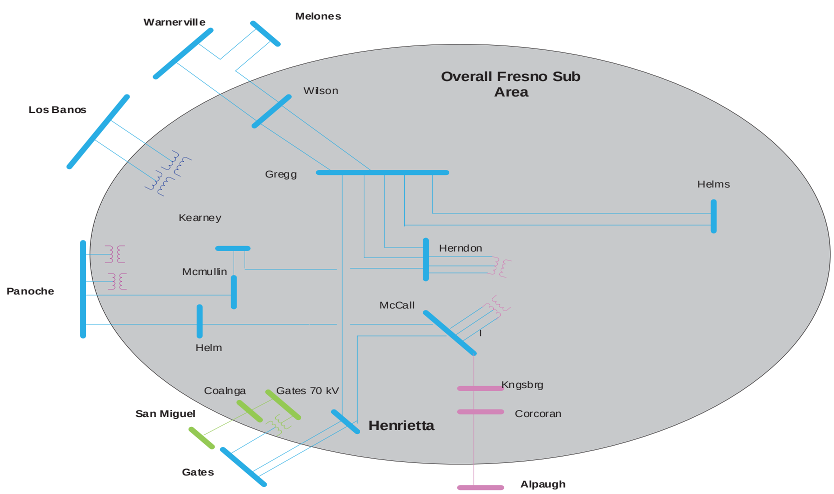
Panoche 230 is out Panoche 115 is in

Corcoran is in Smyrna is out

Coalinga is in San Miguel is out

Fresno LCR Area Diagram

Figure 3.3-48 Fresno LCR Area



Fresno LCR Area Load and Resources

Table 3.3-45 provides the forecast load and resources in Fresno LCR Area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 18:40 PM.

At the local area peak time the estimated, ISO metered, solar output is 12.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-45 Fresno LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	3099	Market, Net Seller, Battery	2815	2815
AAEE	-12	MUNI	212	212
Behind the meter DG	-4	QF	4	4
Net Load	3083	Solar	361	160
Transmission Losses	106	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	3189	Total	3392	3191

Approved transmission projects modeled

Wilson-Le Grand 115 kV Line Reconductoring (Apr 2020)

Oro Loma 70 kV Area Reinforcement (May 2020)

Herndon-Bullard 230kV Reconductoring Project (Jan 2021)

Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade (Jan 2021)

Northern Fresno 115 kV Reinforcement (Revised scope – Mar 2021)

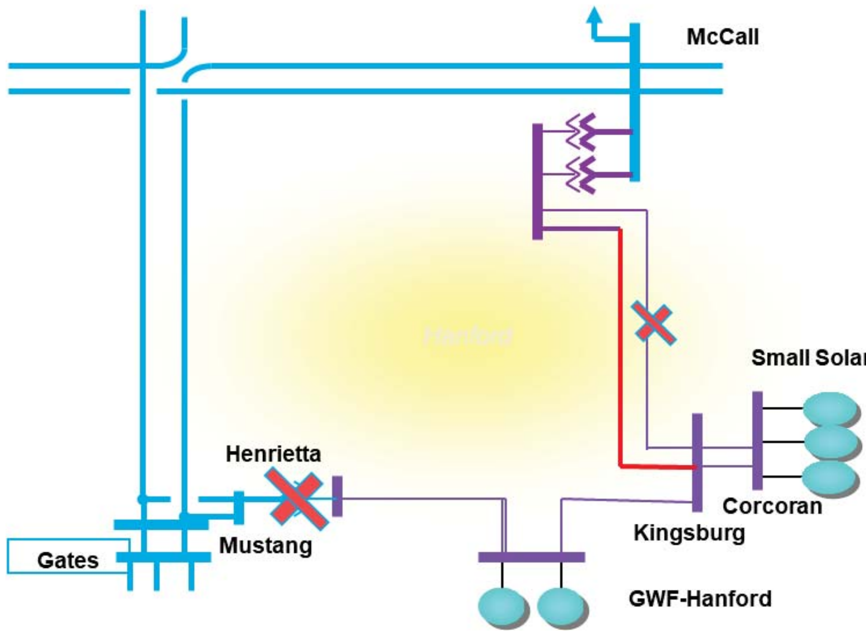
Panoche – Oro Loma 115 kV Line Reconductoring (Apr 2021)

3.3.6.2 *Hanford Sub-area*

Hanford is a Sub-area of the Fresno LCR Area.

Hanford LCR Sub-area Diagram

Figure 3.3-49 Hanford LCR Sub-area



Hanford LCR Sub-area Load and Resources

Table 3.3-46 provides the forecast load and resources in Hanford LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-46 Hanford LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	207	Market, Net Seller	125	125
AAEE	-1	MUNI	0	0
Behind the meter DG	-3	QF	0	0
Net Load	203	Solar	25	11
Transmission Losses	6	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	209	Total	150	136

Hanford LCR Sub-area Hourly Profiles

Figure 3.3-50 illustrates the forecast 2021 profile for the peak day for the Hanford sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-51 illustrates the forecast 2021 hourly profile for

Hanford sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-50 Hanford LCR Sub-area 2021 Peak Day Forecast Profiles

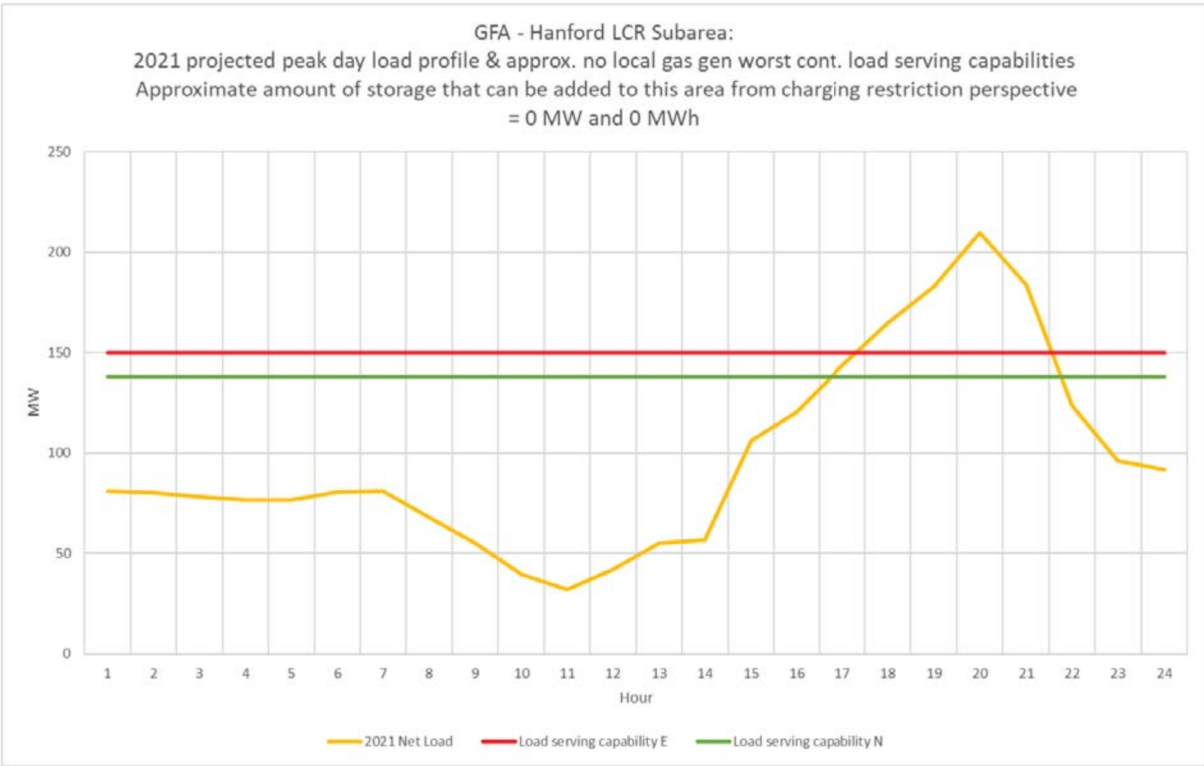
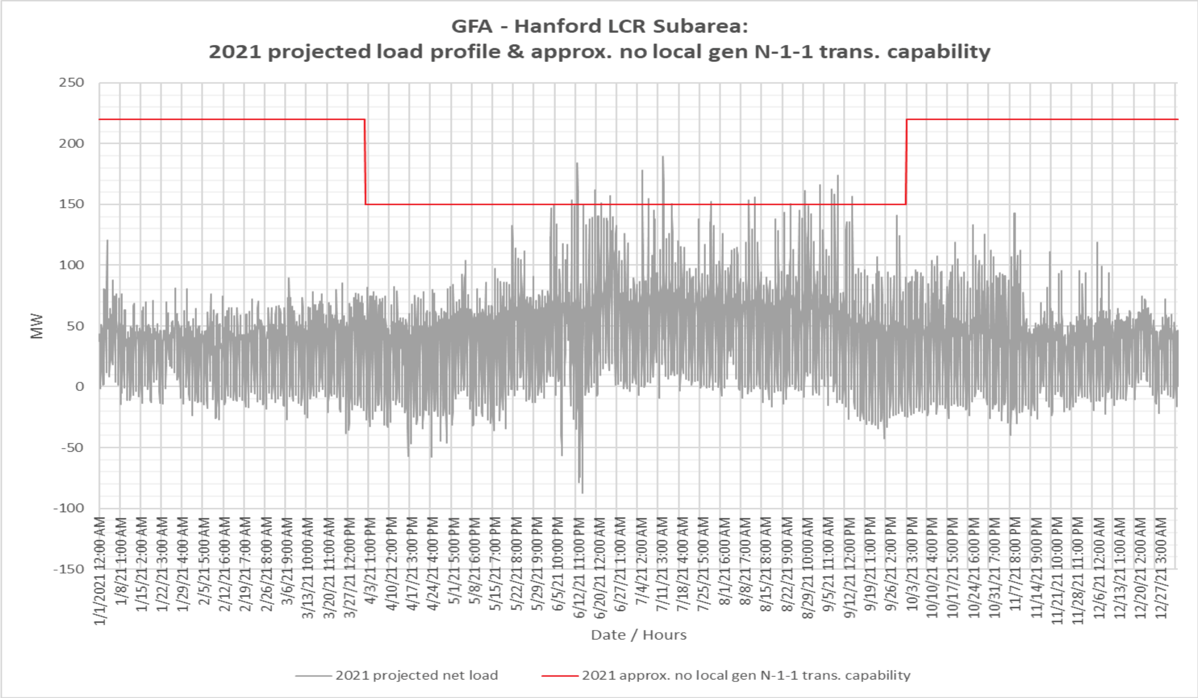


Figure 3.3-51 Hanford LCR Sub-area 2021 Forecast Hourly Profiles



Hanford LCR Sub-area Requirement

Table 3.3-47 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 58 MW.

Table 3.3-47 Hanford LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	McCall-Kingsburg #2 115 kV	McCall-Kingsburg #1 115 kV line and Henrietta 230/115 kV TB#3	58

Effectiveness factors:

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

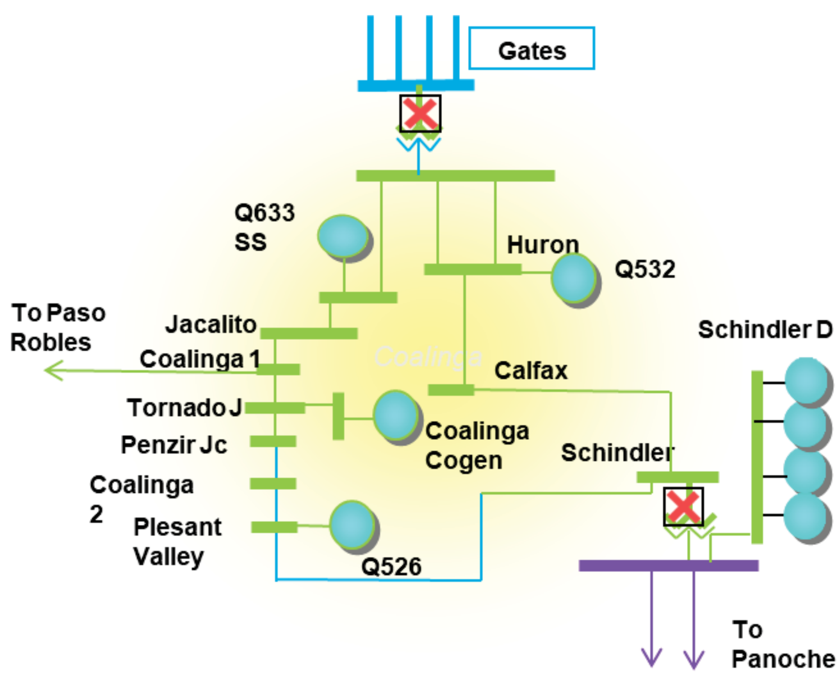
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.3 *Coalinga Sub-area*

Coalinga is a Sub-area of the Fresno LCR Area.

Coalinga LCR Sub-area Diagram

Figure 3.3-52 Coalinga LCR Sub-area



Coalinga LCR Sub-area Load and Resources

Table 3.3-48 provides the forecast load and resources in Coalinga LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-48 Coalinga LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	92	Market, Net Seller	0	0
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	3	3
Net Load	91	Solar	13	6
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	93	Total	16	9

Coalinga LCR Sub-area Hourly Profiles

Figure 3.3-53 illustrates the forecast 2021 profile for the peak day for the Coalinga sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-54 illustrates the forecast 2021 hourly profile for Coalinga sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-53 Coalinga LCR Sub-area 2021 Peak Day Forecast Profiles

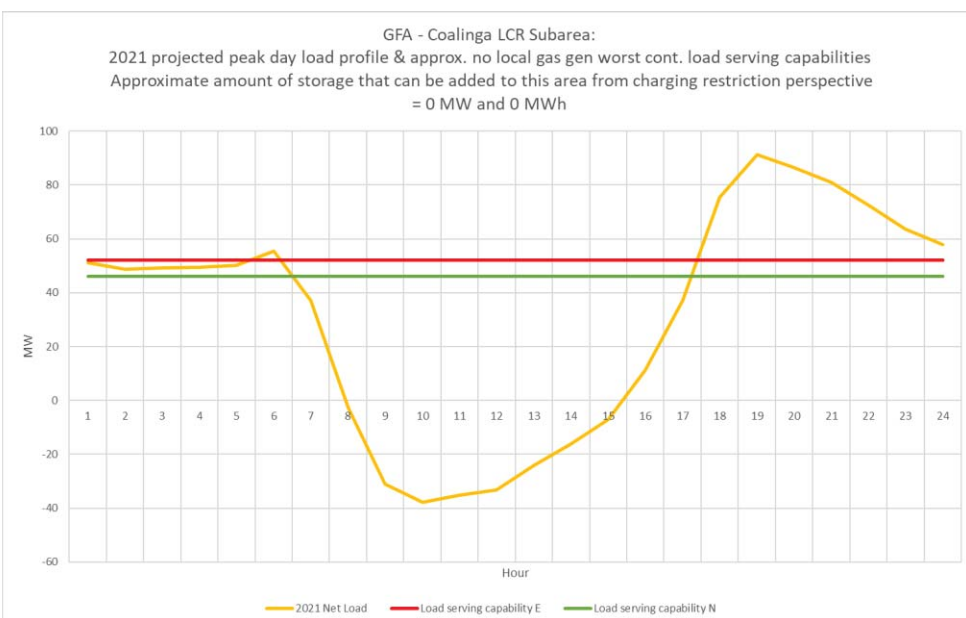
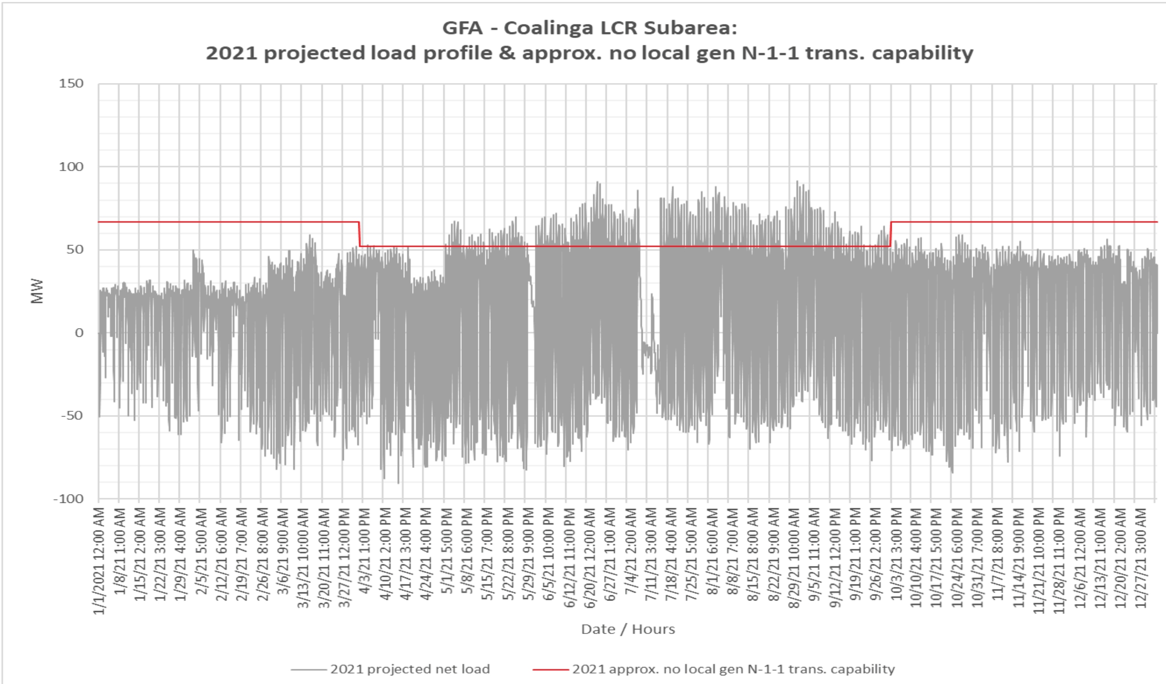


Figure 3.3-54 Coalinga LCR Sub-area 2021 Forecast Hourly Profiles



Coalinga LCR Sub-area Requirement

Table 3.3-49 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 57 MW including a 48 MW at peak deficiency and 41 MW NQC deficiency.

Table 3.3-49 Coalinga LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	San-Miguel-Coalinga 70 kV Line and Voltage Instability	T-1/T-1: Gates 230/70 kV TB #5 and Schindler 115/70 kV TB#1	57 (48 at Peak & 41 NQC)

Effectiveness factors:

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

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

3.3.6.4 *Borden Sub-area*

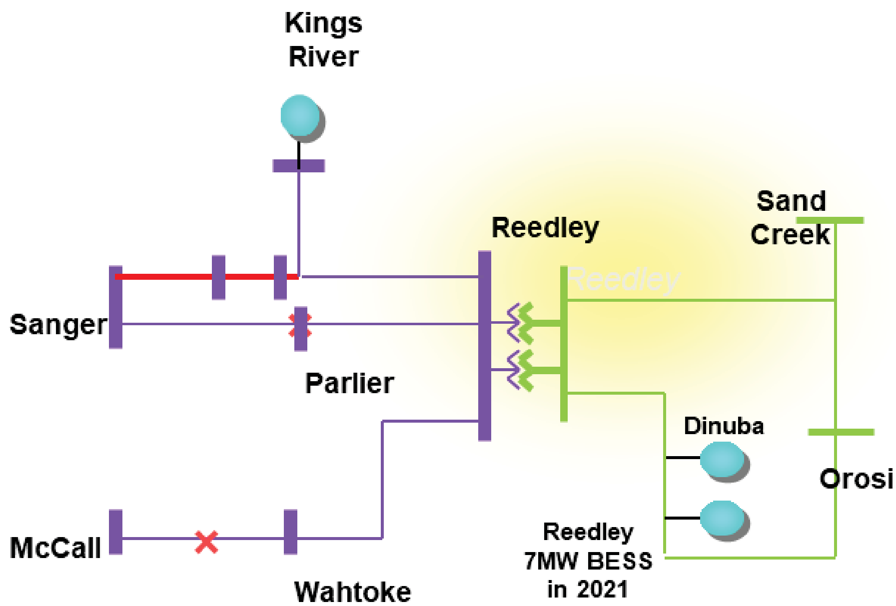
Borden sub-area has no requirements in year 2021.

3.3.6.5 *Reedley Sub-area*

Reedley is a Sub-area of the Fresno LCR Area.

Reedley LCR Sub-area Diagram

Figure 3.3-55 Reedley LCR Sub-area



Reedley LCR Sub-area Load and Resources

Table 3.3-50 provides the forecast load and resources in Reedley LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-50 Reedley LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	207	Market, Net Seller	51	51
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	206	LTPP Preferred Resources	0	0
Transmission Losses	58	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	264	Total	51	51

Reedley LCR Sub-area Hourly Profiles

Figure 3.3-56 illustrates the forecast 2021 profile for the peak day for the Reedley sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-57 illustrates the forecast 2021 hourly profile for

Reedley sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-56 Reedley LCR Sub-area 2021 Peak Day Forecast Profiles

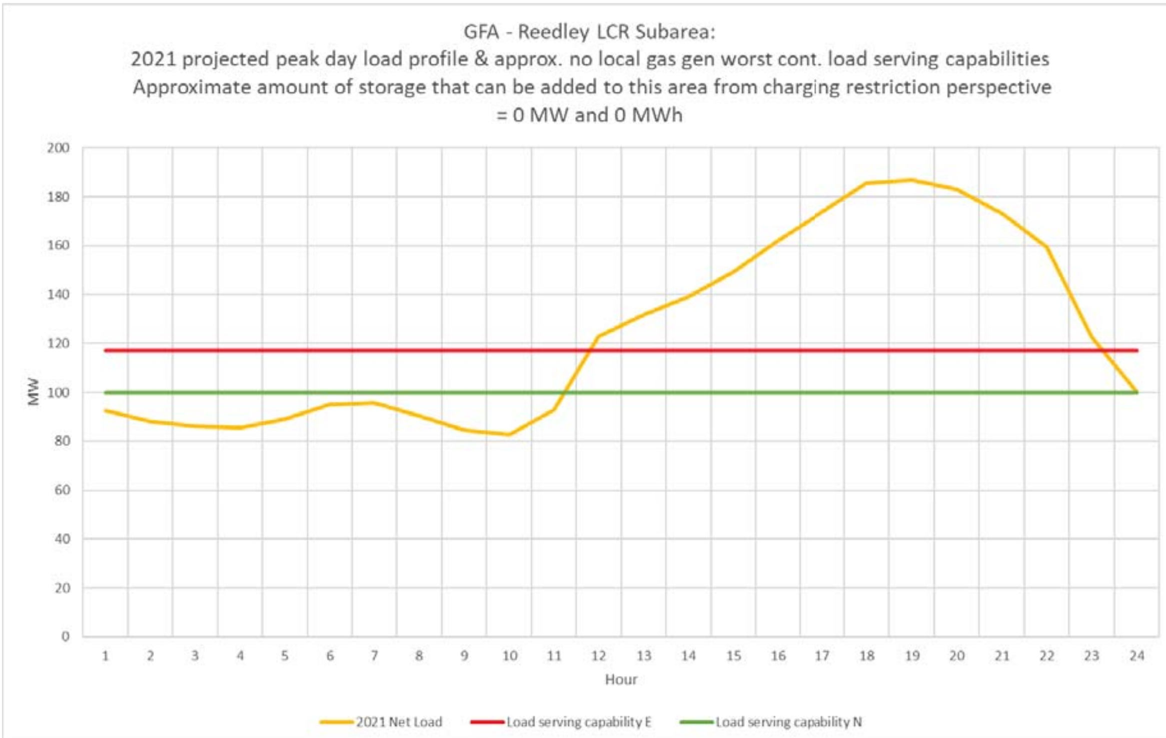
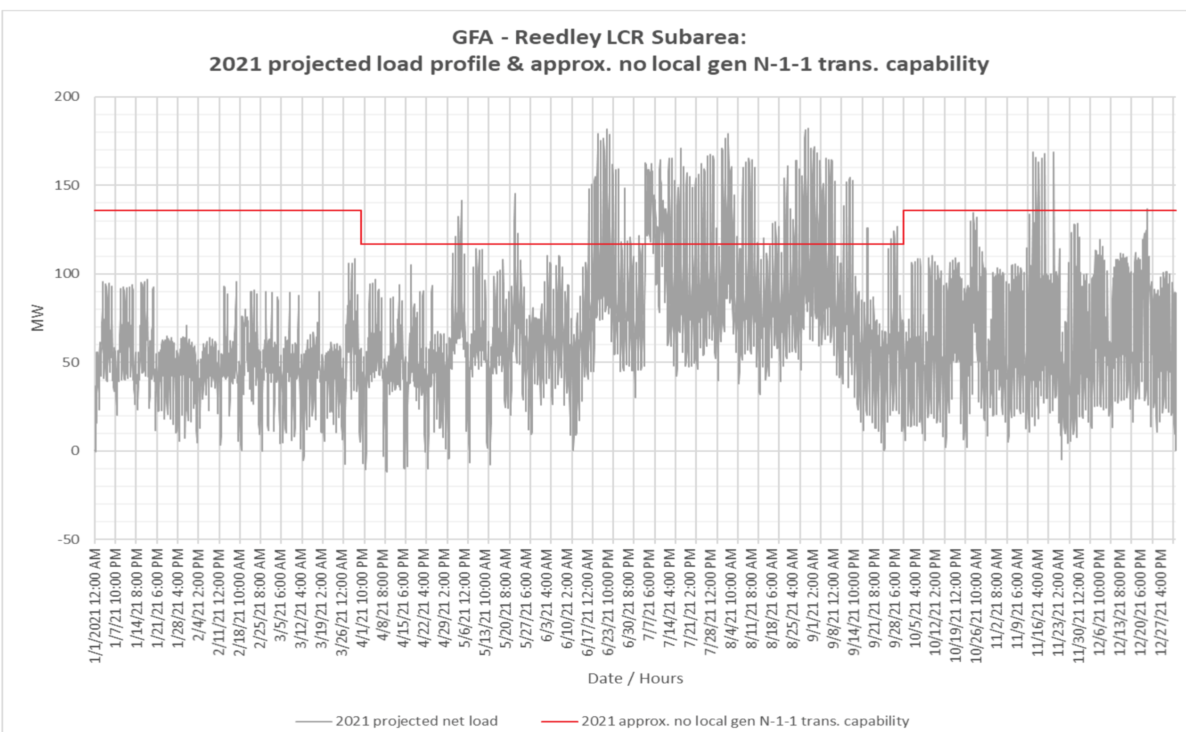


Figure 3.3-57 Reedley LCR Sub-area 2021 Forecast Hourly Profiles



Reedley LCR Sub-area Requirement

Table 3.3-51 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 82 MW with a 31 MW deficiency.

Table 3.3-51 Reedley LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Kings River-Sanger-Reedley 115 kV line with Wahtoke load online	McCall-Reedley 115 kV & Sanger-Reedley 115 kV	82 (31)

Effectiveness factors:

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

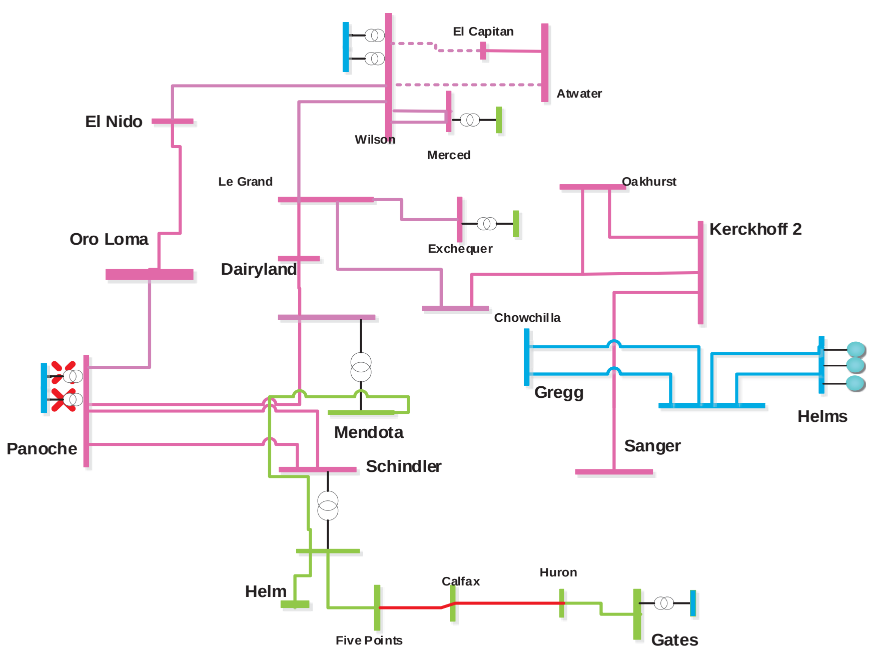
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.6 *Panoche Sub-area*

Panoche is a Sub-area of the Fresno LCR Area.

Panoche LCR Sub-area Diagram

Figure 3.3-58 Panoche LCR Sub-area



Panoche LCR Sub-area Load and Resources

Table 3.3-52 provides the forecast load and resources in Panoche LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-52 Panoche LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	415	Market, Net Seller	282	282
AAEE	-2	MUNI	100	100
Behind the meter DG	-1	QF	3	3
Net Load	412	Solar	89	40
Transmission Losses	12	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	424	Total	474	425

Panoche LCR Sub-area Hourly Profiles

Figure 3.3-59 illustrates the forecast 2021 profile for the peak day for the Panoche sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-60 illustrates the forecast 2021 hourly profile for Panoche sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-59 Panoche LCR Sub-area 2021 Peak Day Forecast Profiles

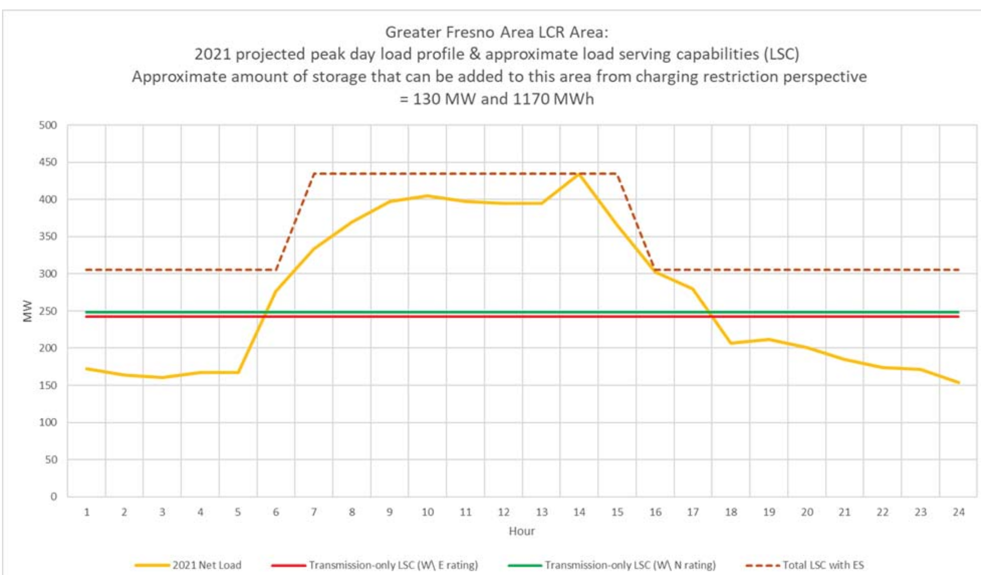
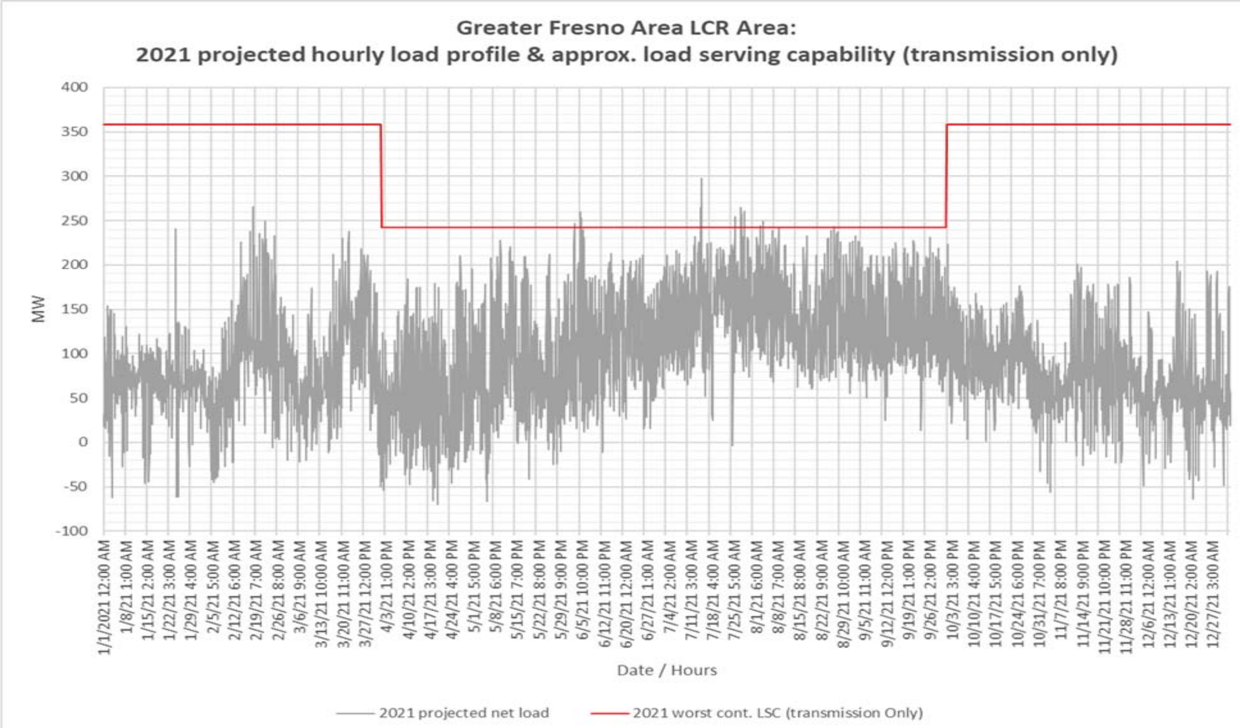


Figure 3.3-60 Panoche LCR Sub-area 2021 Forecast Hourly Profiles



Panoche LCR Sub-area Requirement

Table 3.3-53 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 198 MW.

Table 3.3-53 Panoche LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P6	Five Points-Huron-Gates 70 kV line	Panoche 230/115 kV TB #2 and Panoche 230/115 kV TB #	198

Effectiveness factors:

Effective factors for generators in the Panoche LCR sub-area are in Attachment B table title Panoche.

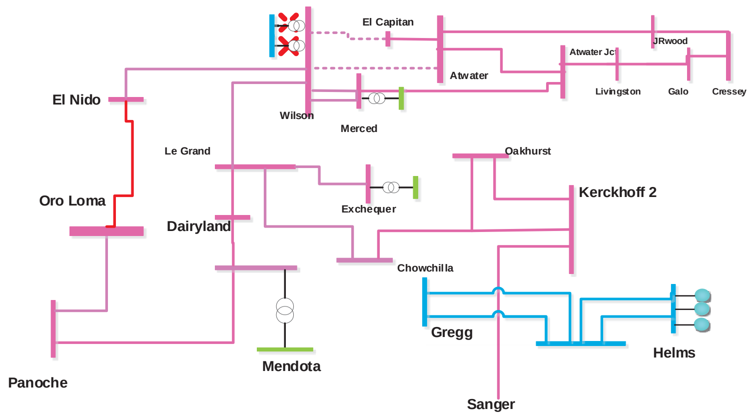
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.7 *Wilson 115 kV Sub-area*

Wilson 115 kV is a Sub-area of the Fresno LCR Area.

Wilson LCR Sub-area Diagram

Figure 3.3-61 Wilson LCR Sub-area



Wilson LCR Sub-area Load and Resources

The Wilson sub-area does not has a defined load pocket with the limits based upon power flow through the area. Table 3.3-56 provides the forecasted resources in the sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-56 Wilson LCR Sub-area 2021 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Wilson sub-area does not have a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	260	260
	MUNI	100	100
	QF	0	0
	Solar	54	24
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	414	384

Wilson LCR Sub-area Hourly Profiles

The Wilson 115 kV sub-area is a flow-through sub-area therefore hourly profiles are not provided.

Wilson LCR Sub-area Requirement

Table 3.3-54 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 416 MW with a 63 MW deficiency at Peak.

Table 3.3-54 Wilson LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Wilson-Oro Loma 115 kV Line (El Nido-Oro Loma 115 kV)	Wilson 230/115kV TB #1 and Wilson 230/115kV TB #2	416 (2 NQC/32 Peak)

Effectiveness factors:

Effective factors for generators in the Wilson 115 kV LCR sub-area are in Attachment B table titled Wilson 115 kV.

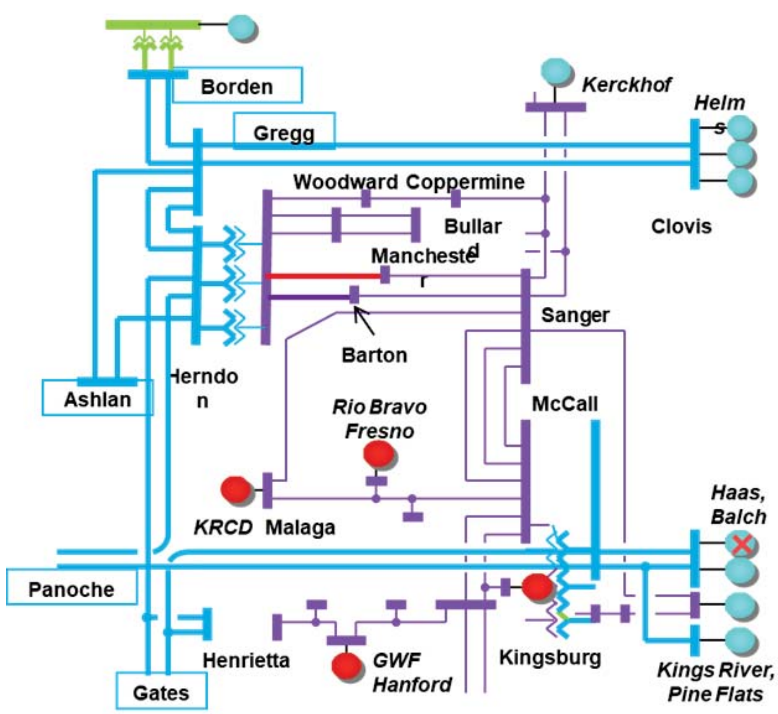
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.8 *Herndon Sub-area*

Herndon is a Sub-area of the Fresno LCR Area.

Herndon LCR Sub-area Diagram

Figure 3.3-62 Herndon LCR Sub-area



Herndon LCR Sub-area Load and Resources

Table 3.3-55 provides the forecast load and resources in Herndon LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-55 Herndon LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1471	Market, Net Seller	997	997
AAEE	-6	MUNI	98	98
Behind the meter DG	-3	QF	1	1
Net Load	1462	Solar	63	28
Transmission Losses	24	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	1486	Total	1159	1124

Herndon LCR Sub-area Hourly Profiles

Figure 3.3-63 illustrates the forecast 2021 profile for the peak day for the Herndon sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-64 illustrates the forecast 2021 hourly profile for Herndon sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-63 Herndon LCR Sub-area 2021 Peak Day Forecast Profiles

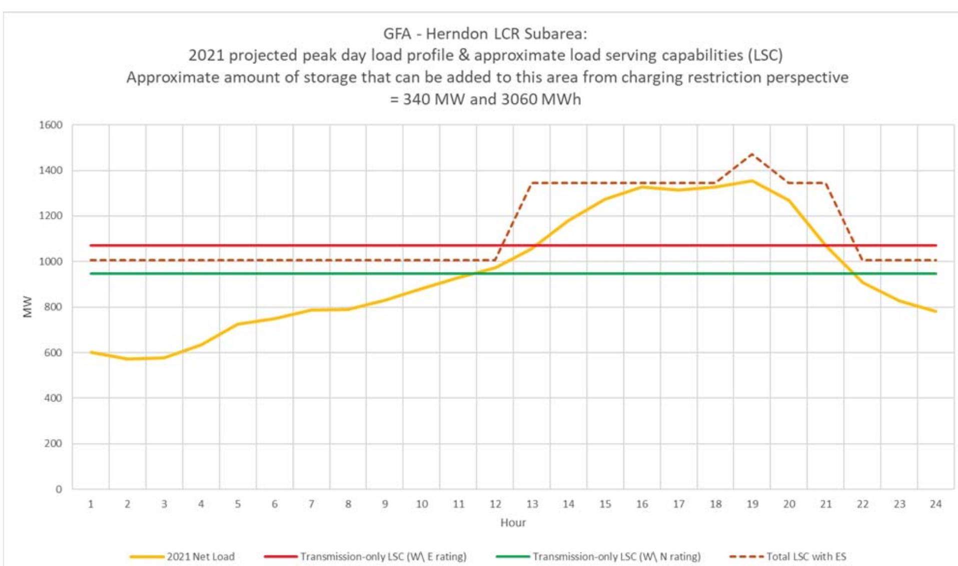
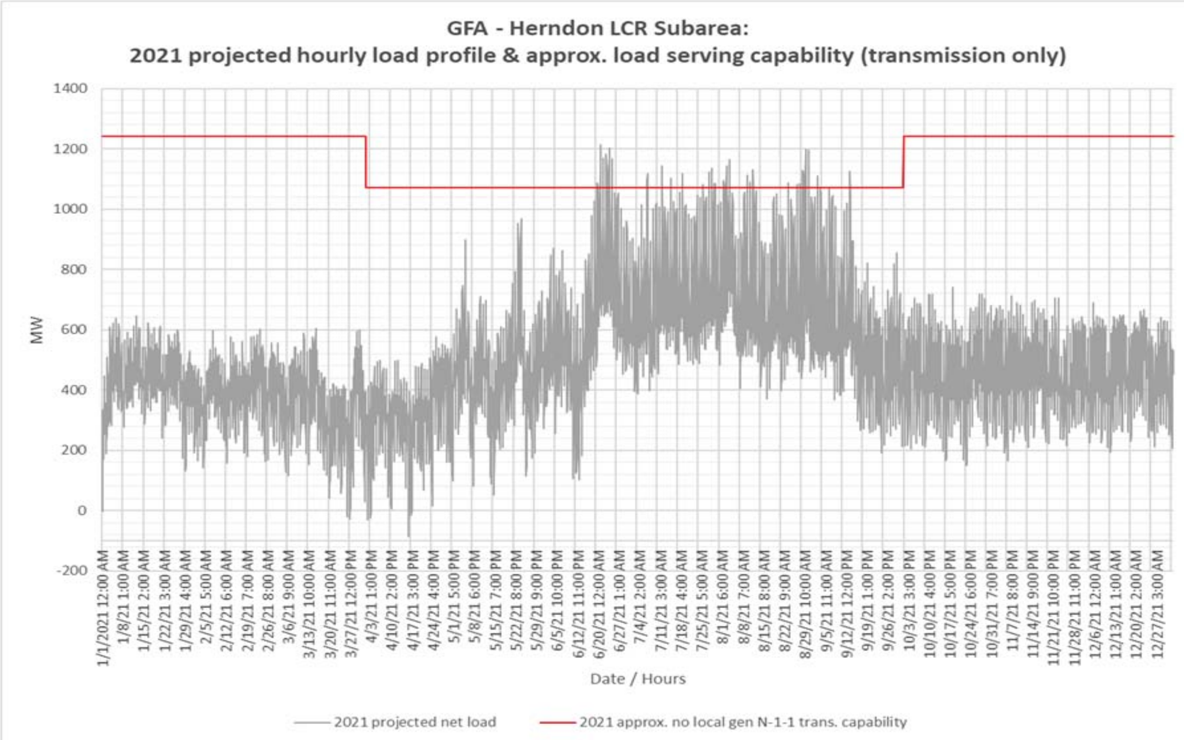


Figure 3.3-64 Herndon LCR Sub-area 2021 Forecast Hourly Profiles



Herndon LCR Sub-area Requirement

Table 3.3-56 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 334 MW.

Table 3.3-56 Herndon LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P6	Herndon-Manchester 115 kV	Herndon-Woodward 115 kV line & Herndon-Barton 115 kV line	334

Effectiveness factors:

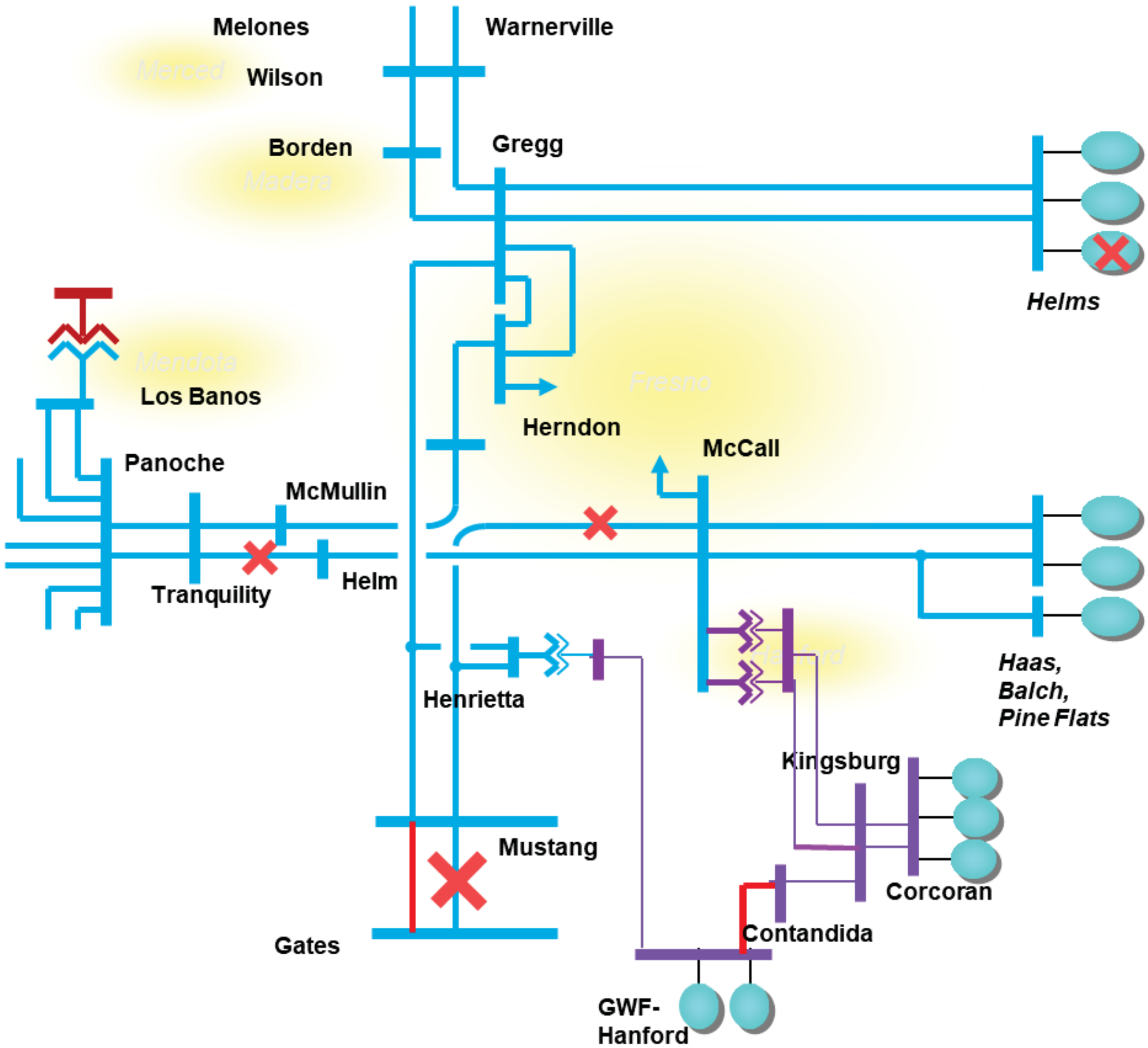
Effective factors for generators in the Herndon LCR Sub-area are in Attachment B table titled Herndon.

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

3.3.6.9 *Fresno Overall area*

Fresno LCR area Diagram

Figure 3.3-65 Fresno LCR area



Fresno Overall LCR area Load and Resources

Table 3.3-45 provides the forecast load and resources in Fresno LCR area in 2021. The list of generators within the LCR area are provided in Attachment A.

Fresno Overall LCR area Hourly Profiles

Figure 3.3-66 illustrates the forecast 2021 profile for the peak day for the Fresno Overall sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-67 illustrates the forecast 2021 hourly profile for Fresno Overall sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-66 Fresno LCR area 2021 Peak Day Forecast Profiles

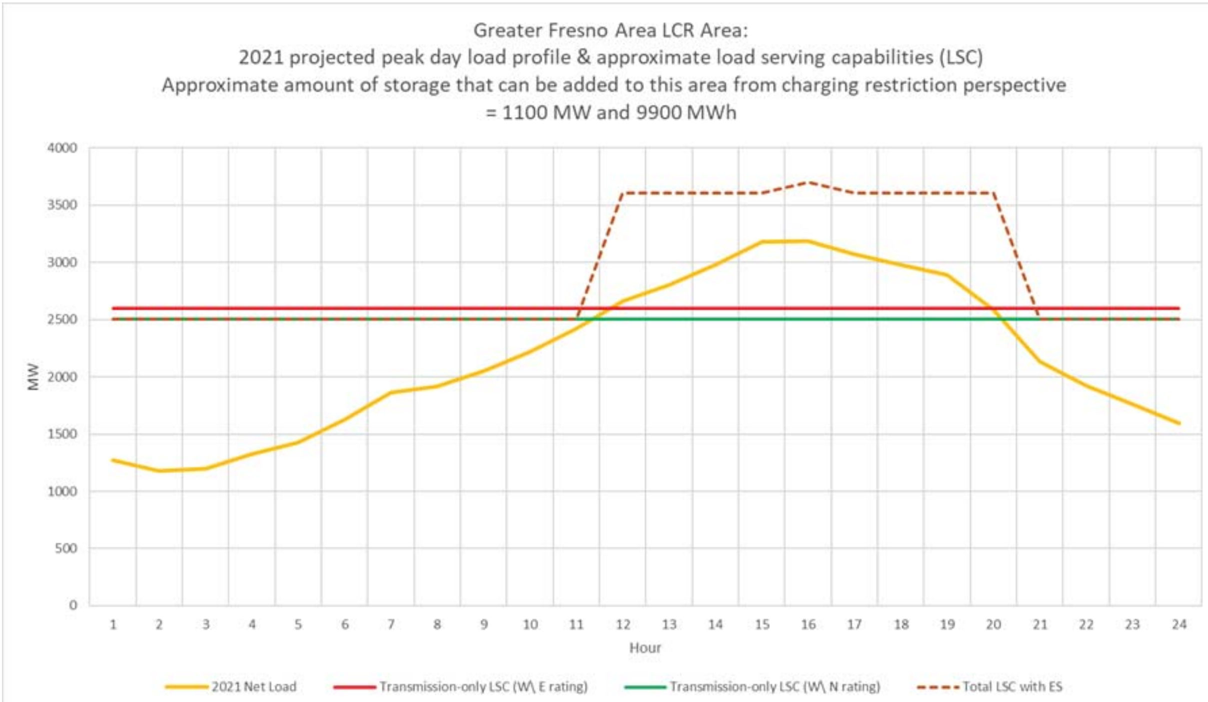
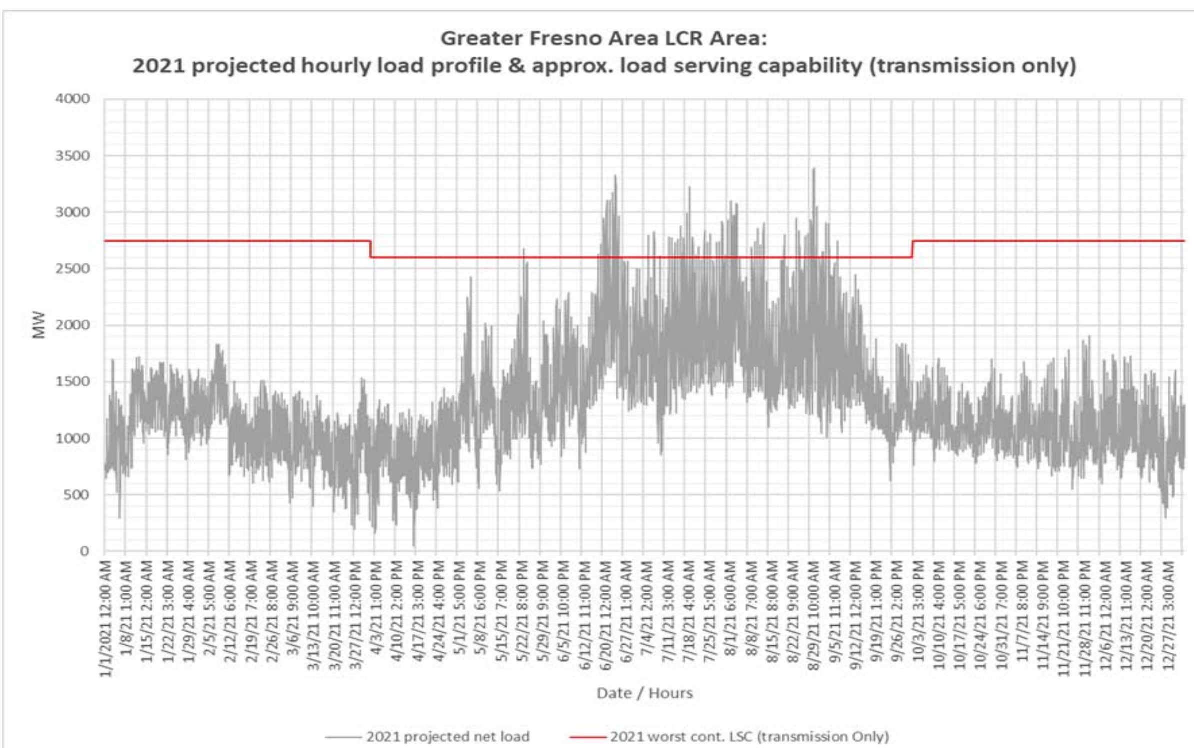


Figure 3.3-67 Fresno LCR area 2021 Forecast Hourly Profiles



Fresno Overall LCR Area Requirement

Table 3.3-57 identifies the area LCR requirements. The LCR Requirement for a Category P6 contingency is 1694 MW.

Table 3.3-57 Fresno Overall LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First limit	P6	GWF-Contandida 115 kV Line	Panoche-Helm 230 kV Line and Gates-McCall 230 kV Line	1694

Effectiveness factors:

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

Changes compared to 2020 requirements

Compared with 2020 the load forecast decreased by 89 MW and the LCR need remained the same due to change in limiting constraint.

3.3.7 Kern Area

3.3.7.1 *Area Definition:*

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

Midway-Kern PP #1 230 kV Line

Midway-Kern PP #3 230 kV Line

Midway-Kern PP #4 230 kV Line

Wheeler Ridge #4 230/70 kV Transformer Bank

Wheeler Ridge #5 230/70 kV Transformer Bank

Famoso-Lerdo 115 kV Line (Normal Open)

Wasco-Famoso 70 kV Line (Normal Open)

Copus-Old River 70 kV Line (Normal Open)

Copus-Old River 70 kV Line (Normal Open)

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

Midway 230 kV is out and Bakersfield 230 kV is in

Midway 230 kV is out and Stockdale 230 kV is in

Midway 230 kV is out Kern PP 230 kV is in

Wheeler Ridge 230 kV is out and Wheeler Ridge 70 kV is in

Wheeler Ridge 230 kV is out and Wheeler Ridge 70 kV is in

Famoso 115 kV is out Cawelo 115 kV is in

Wasco 70 kV is out Mc Farland 70 kV is in

Copus 70 kV is out, South Kern Solar 70 kV is in

Lakeview 70 kV is out, San Emidio Junction 70 kV is in

Kern LCR Area Diagram

Figure 3.3-68 Kern LCR Area

Kern LCR Area Load and Resources

Table 3.3-58 provides the forecast load and resources in Kern LCR Area in 2021. The list of generators within the LCR area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 19:20 PM.

At the local area peak time the estimated, ISO metered, solar output is 0.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-58 Kern LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1278	Market, Net Seller	330	330
AAEE	-5	MUNI	0	0
Behind the meter DG	0	QF	5	5
Net Load	1273	Solar	78	0
Transmission Losses	12	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	1285	Total	413	335

Approved transmission projects modeled

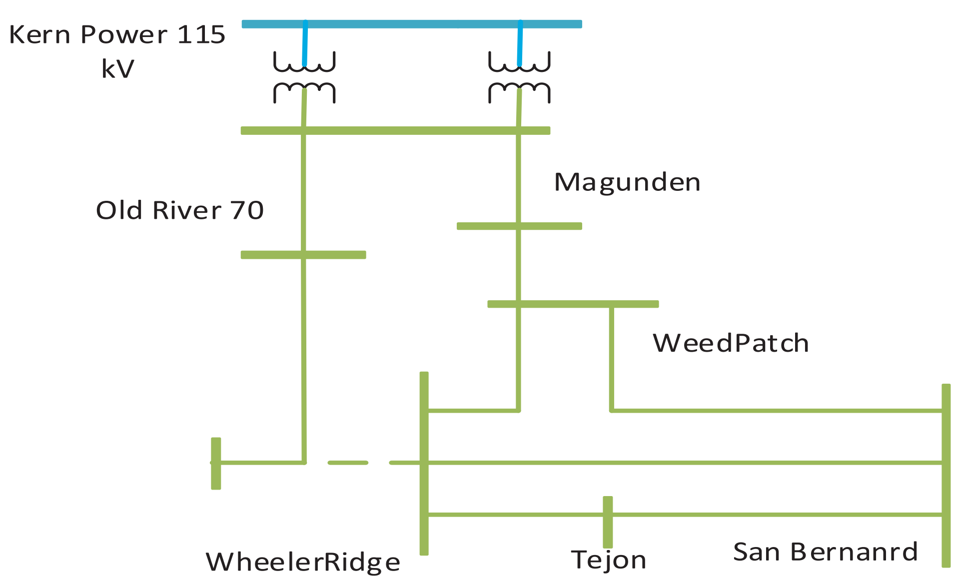
Kern PP 230 kV area reinforcement project.

3.3.7.2 *Kern 70 kV Sub-area*

Kern 70 kV is a Sub-area of the Kern LCR Area.

Kern 70 kV LCR Sub-area Diagram

Figure 3.3-69 Kern 70 kV LCR Sub-area



Kern 70 kV LCR Sub-area Load and Resources

Table 3.3-59 provides the forecast load and resources in Kern 70 kV LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-59 Kern 70 kV LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	224	Market, Net Seller	4	4
AAEE	0.7	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	223	Solar	13	0
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	225	Total	17	4

Kern 70 kV LCR Sub-area Hourly Profiles

Figure 3.3-70 illustrates the forecast 2021 profile for the peak day for the Kern-Kern PWR 70 kV LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective.Figure 3.3-71 illustrates the forecast 2021 hourly profile for Kern-Kern PWR 70 kV LCR sub-area with the Category P6 emergency load serving capability without local gas resources

Figure 3.3-70 Kern 70 kV LCR Sub-area 2021 Peak Day Forecast Profiles

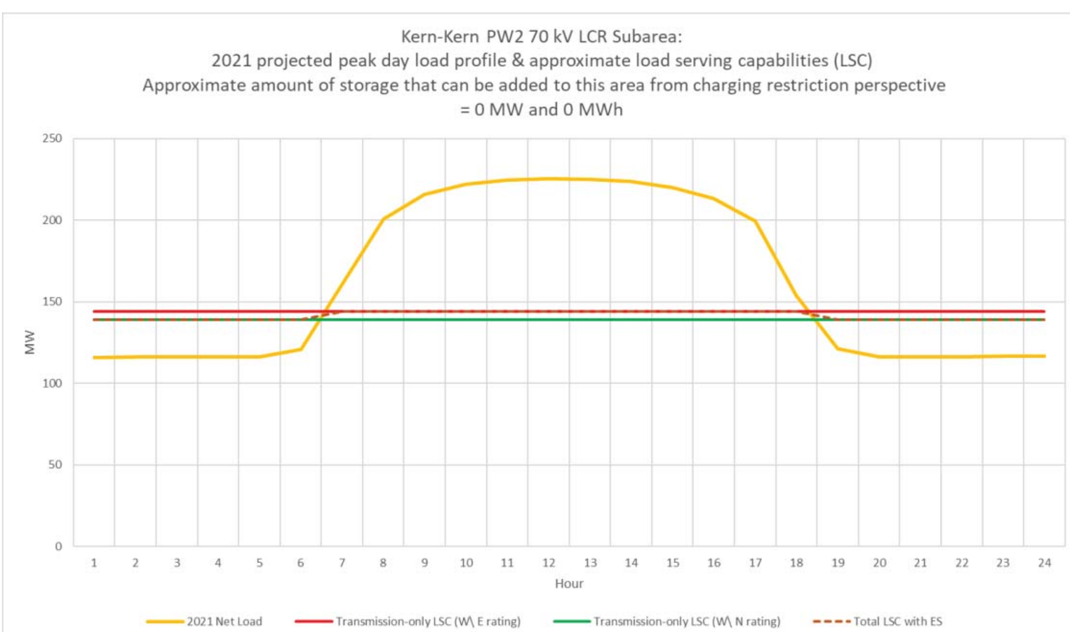
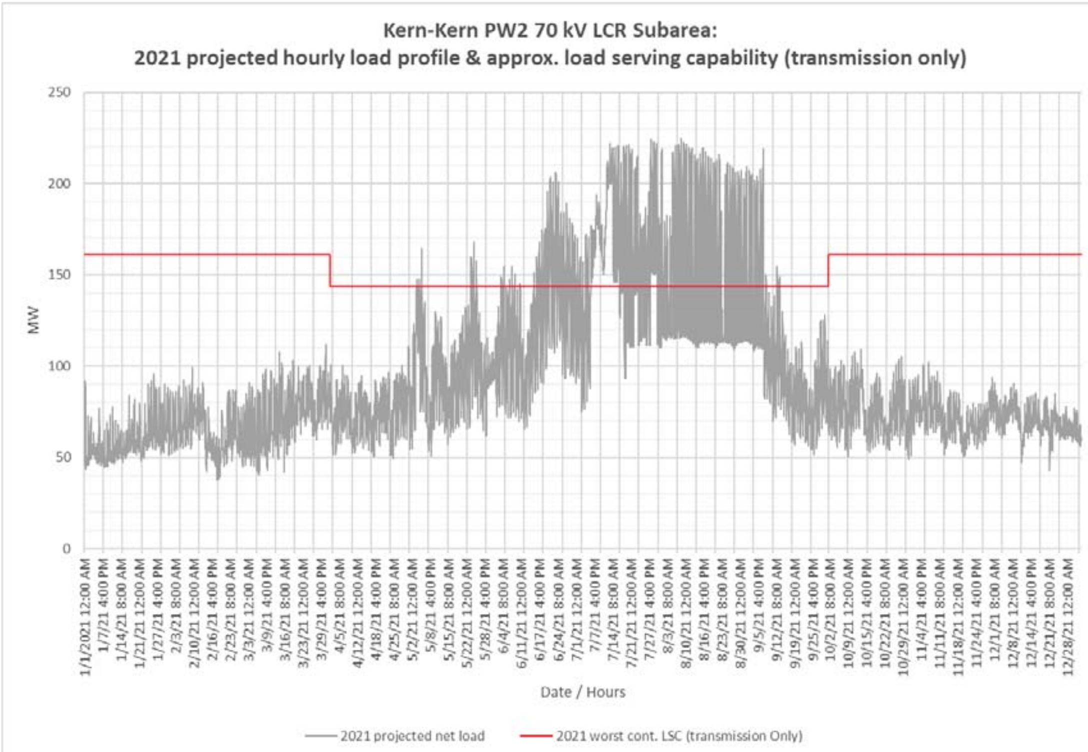


Figure 3.3-71 Kern 70 kV LCR Sub-area 2021 Forecast Hourly Profiles



Kern 70 kV LCR Sub-area Requirement

Table 3.3-60 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 80 MW including a 63 MW NQC deficiency or 76 MW at peak deficiency.

Table 3.3-60 Kern 70 kV LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	P6	Weedpatch to Weedpatch SF 70 kV	Kern PW1 115/70 kV T/F & Kern PW2 115/70 kV T/F	80 (63 NQC/76 Peak)

Effectiveness factors:

All units within the Kern 70 kV Sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.3 *Kern PWR-Tevis Sub Area*

Kern PWR-Tevis is a new Sub-area of the Kern LCR Area.

Kern PWR-Tevis Sub-area Diagram

Please see Figure 3.3-68 for Kern PWR-Tevis sub-area diagram

Kern PWR-Tevis Sub-area Load and Resources

Table 3.3-61 provides the forecast load and resources in Kern PWR-Tevis sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-61 Kern PWR-Tevis LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	198	Market, Net Seller	0	0
AAEE	0	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	197	Solar	52	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	198	Total	52	0

Kern PWR-Tevis Sub-area Sub-area Hourly Profiles

The profile for this sub area was not created as this is a new pocket and gets eliminated in the 2025 LCR study because of approved transmission projects in the area.

Kern PWR-Tevis LCR Sub-area Requirement

Table 3.3-62 identifies the sub-area LCR requirements. The LCR requirement for Category P2 contingency is 55 MW including a 3 MW NQC deficiency or 55 MW at peak deficiency.

Table 3.3-62 Kern PWR-Tevis LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	P2	Kern-Lamont 115 kV Lines (Kern-Tevis Jct 2/Tevis J1)	KERN PWR 115kV - Section 1E & 1D	55 (3 NQC/ 55 Peak)

Effectiveness factors:

All units within the Kern PWR-Tevis sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.4 *Westpark Sub-area*

Westpark is a Sub-area of the Kern LCR Area.

Westpark LCR Sub-area Diagram

Please see Figure 3.3-68 for Westpark sub-area diagram.

Westpark LCR Sub-area Load and Resources

Table 3.3-63 provides the forecast load and resources in Westpark LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-63 Westpark LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	163	Market, Net Seller	44	44
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	162	LTPP Preferred Resources	0	0
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	162	Total	44	44

Westpark LCR Sub-area Hourly Profiles

Figure 3.3-72 illustrates the forecast 2021 profile for the peak day for the Westpark LCR sub-area with the Category P3 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-73 illustrates the forecast 2021 hourly profile for Westpark LCR sub-area with the Category P3 emergency load serving capability without local gas resources

Figure 3.3-72 Westpark LCR Sub-area 2021 Peak Day Forecast Profiles

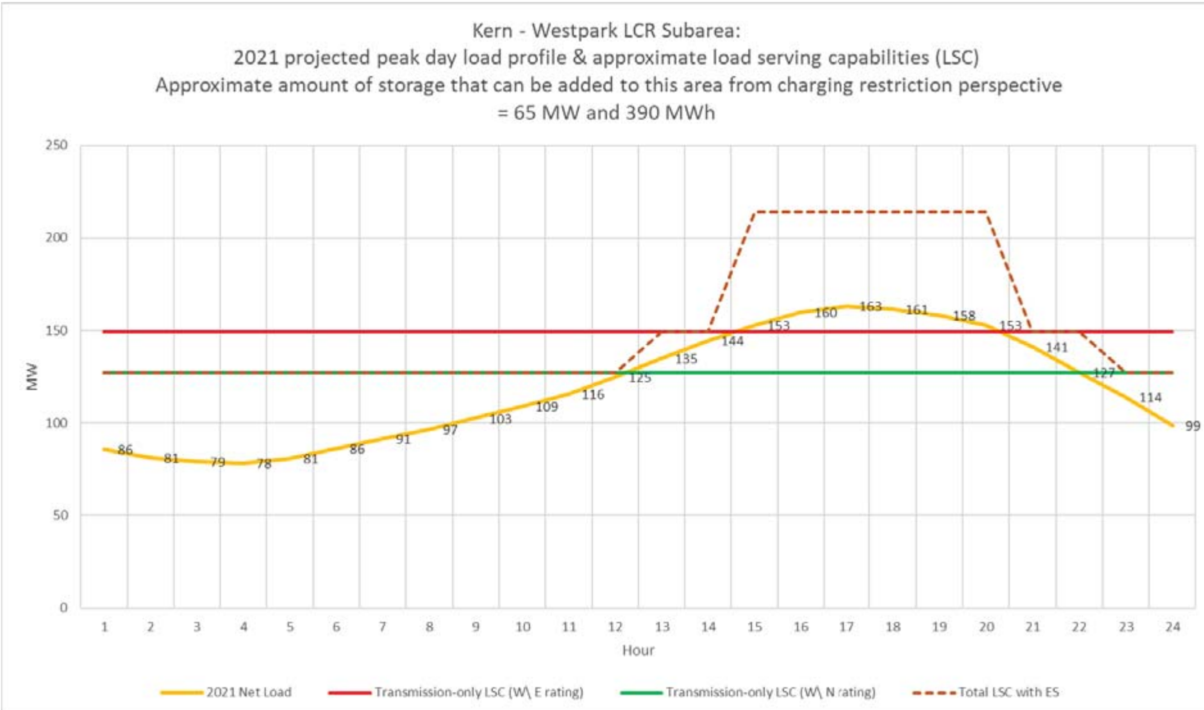
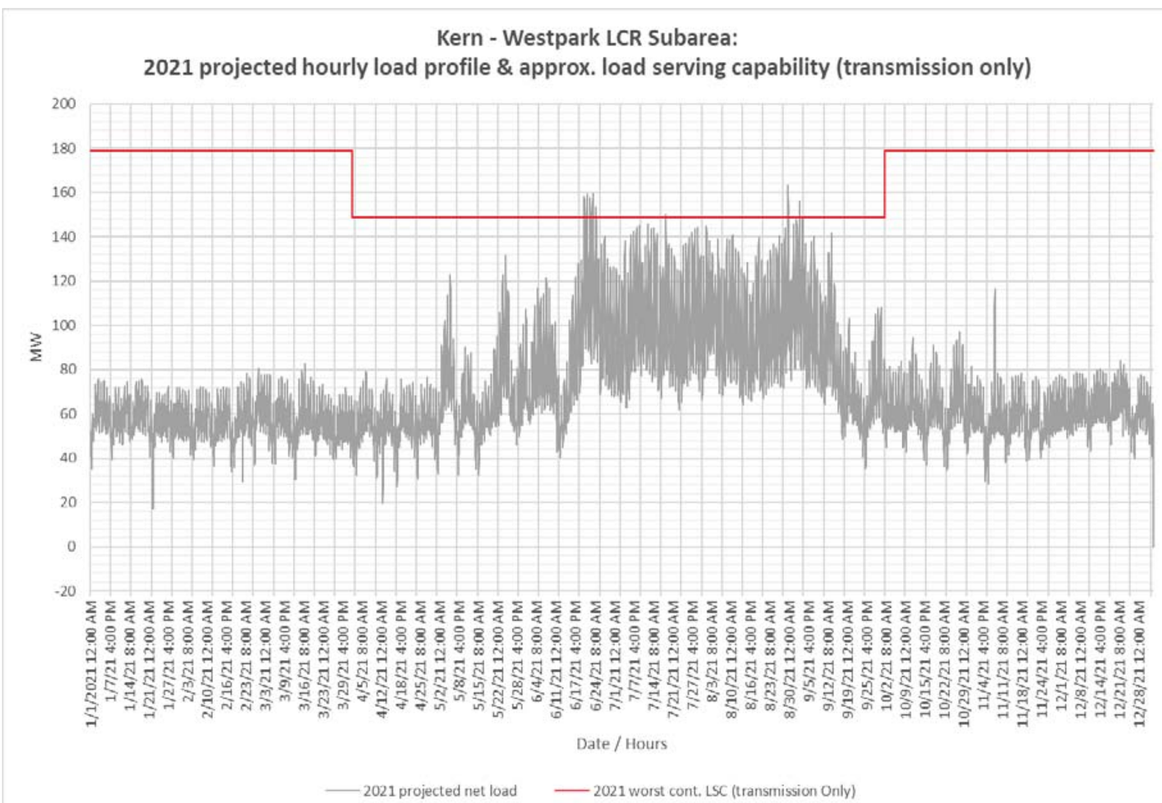


Figure 3.3-73 Westpark LCR Sub-area 2021 Forecast Hourly Profiles



Westpark LCR Sub-area Requirement

Table 3.3-64 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 58 MW including a 14 MW peak deficiency.

Table 3.3-64 Westpark LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	P3	Kern-West Park #2 115 kV	Kern-West Park #1 115 kV and PSE-Bear Generation	58 (14)

Effectiveness factors:

All units within the Westpark Sub-area have the same effectiveness factor.

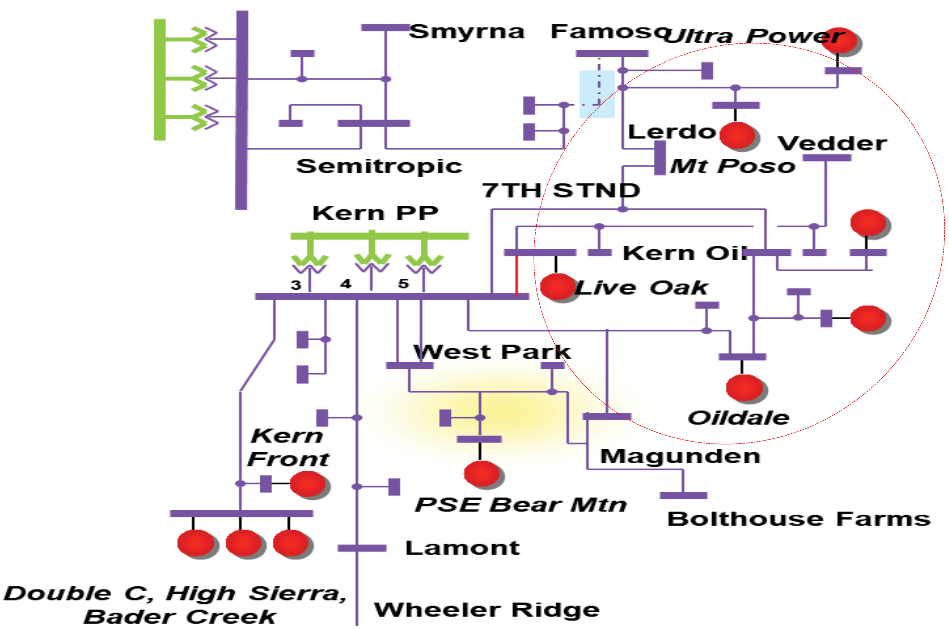
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.5 *Kern Oil Sub-area*

Kern Oil is a Sub-area of the Kern LCR Area.

Kern Oil LCR Sub-area Diagram

Figure 3.3-74 Kern Oil LCR Sub-area



Kern Oil LCR Sub-area Load and Resources

Table 3.3-65 provides the forecast load and resources in Kern Oil LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-65 Kern Oil LCR Sub-area 2021 Forecast Load and Resources

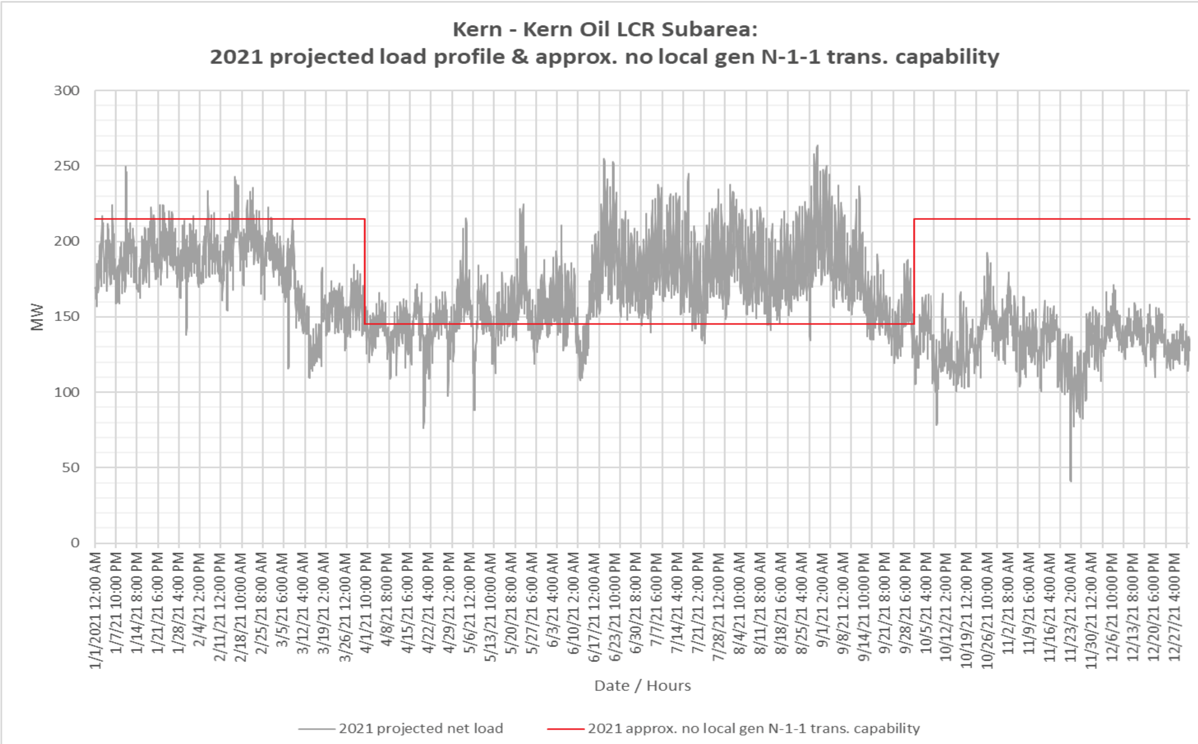
Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	289	Market, Net Seller	95	95
AAEE	-2	MUNI	0	0
Behind the meter DG	0	QF	5	5
Net Load	287	Solar	7	0
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	289	Total	107	100

Kern Oil LCR Sub-area Hourly Profiles

Figure 3.3-75 illustrates the forecast 2021 profile for the peak day for the Kern Oil LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-76 illustrates the forecast 2021 hourly profile for Kern Oil LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.3-75 Kern Oil LCR Sub-area 2021 Peak Day Forecast Profiles

Figure 3.3-76 Kern Oil LCR Sub-area 2021 Forecast Hourly Profiles



Kern Oil LCR Sub-area Requirement

Table 3.3-66 identifies the sub-area LCR requirements. The LCR requirement for Category P2 contingency is 155 MW including a 48 MW NQC deficiency or 55 MW at peak deficiency.

Table 3.3-66 Kern Oil LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	P2	Kern PP-7th Standard 115 kV Line	KERN PWR 115kV Section 2E	155 (48 NQC/55 Peak)

Effectiveness factors:

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.6 *South Kern PP Sub-area*

South Kern PP is Sub-area of the Kern LCR Area.

South Kern PP LCR Sub-area Diagram

Figure 3.3-77 South Kern PP LCR Sub-area

South Kern PP LCR Sub-area Load and Resources

Refer to Table 3.3-58 Kern Area Load and Resources table.

South Kern PP LCR Sub-area Hourly Profiles

Figure 3.3-78 illustrates the forecast 2021 profile for the peak day for the South Kern PP LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-79 illustrates the forecast 2021 hourly profile for South Kern PP LCR sub-area with the Category P7 emergency load serving capability without local gas resources.

Figure 3.3-78 South Kern PP LCR Sub-area 2021 Peak Day Forecast Profiles

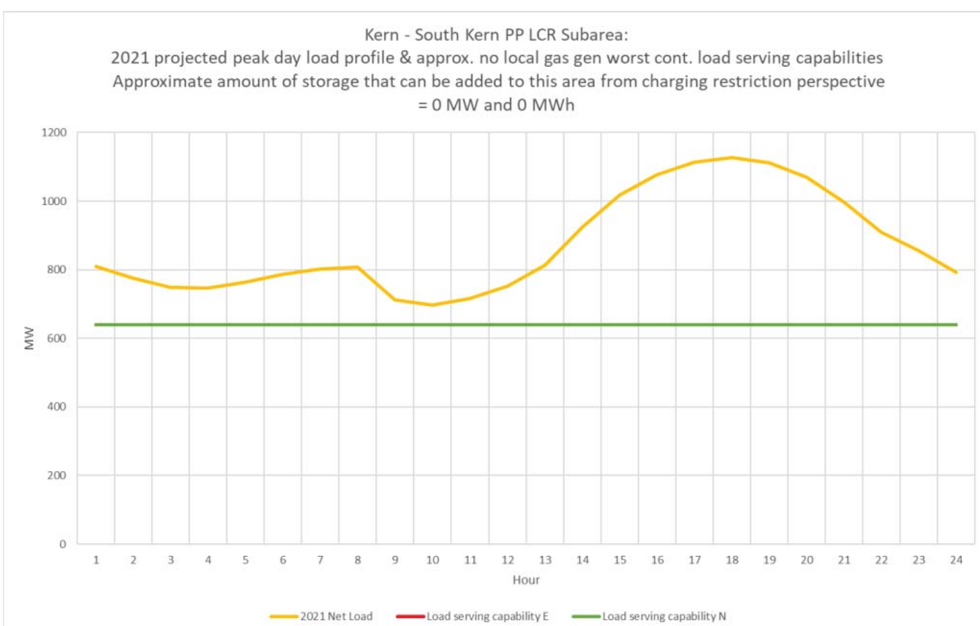
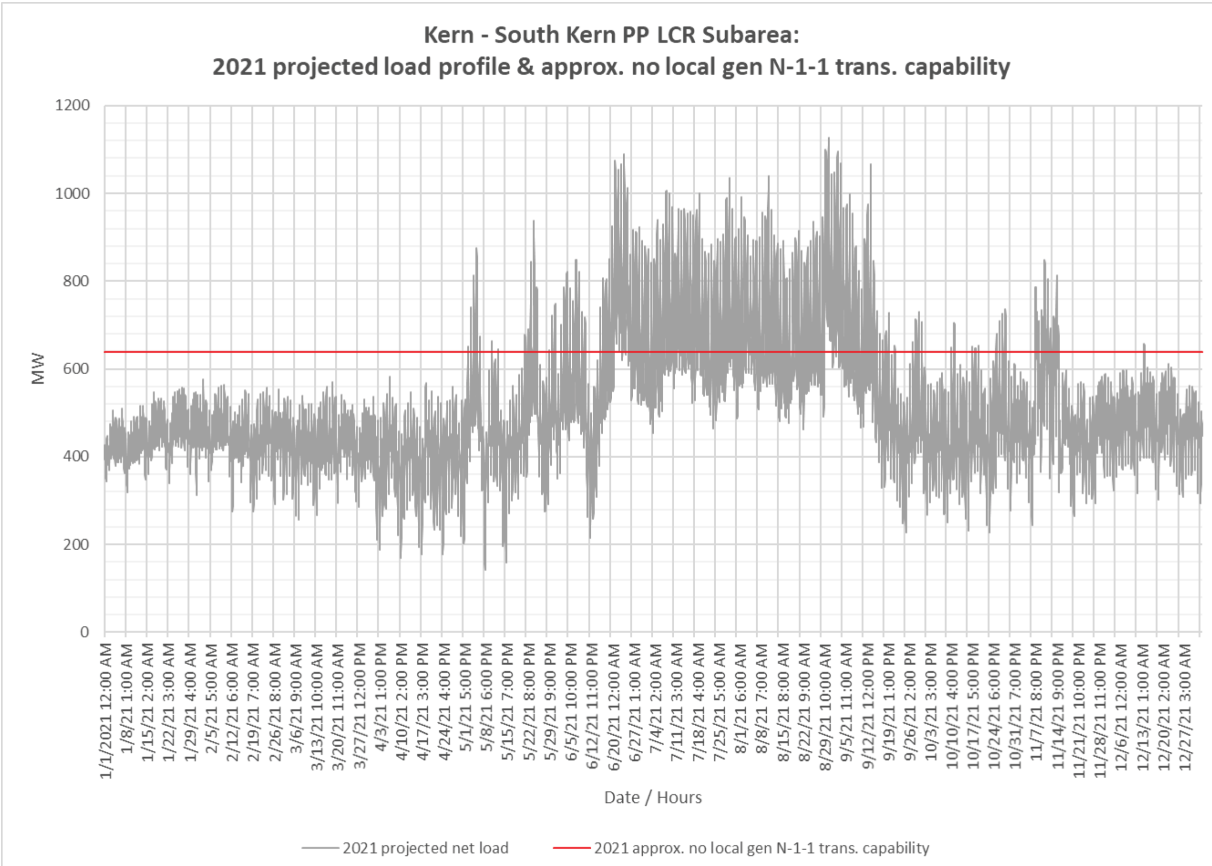


Figure 3.3-79 South Kern PP LCR Sub-area 2021 Forecast Hourly Profiles



South Kern PP LCR Sub-area Requirement

Table 3.3-67 identifies the sub-area LCR requirements. The LCR requirement for Category P7 contingency is 632 MW including a 219 MW NQC deficiency or 297 MW at peak deficiency.

Table 3.3-67 South Kern PP LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	P7	Midway-Kern #1 230 kV Line (Kern PP-Stockdale Jct 1)	Midway-Kern PP # 2 & # 3 230 kV Lines	632 (219 NQC/ 297 Peak)

Effectiveness factors:

All units within the South Kern PP sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.7 *Kern Area Overall Requirements*

Kern LCR Area Overall Requirement

Table 3.3-68 identifies the limiting facility and contingency that establishes the Kern Area 2021 LCR requirements. The LCR requirement for Category P7 (Multiple Contingency) is 632 MW including a 219 MW NQC deficiency or a 297 MW deficiency.

Table 3.3-68 Kern Overall LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	P7	Aggregate of Sub-areas.		632 (219 NQC/297 Peak)

Kern Overall LCR Area Hourly Profile

Refer to South Kern PP LCR area profiles.

Changes compared to 2020 requirements

Compared with 2020 the load forecast increased by 116 MW and the LCR requirement has increased by 40 MW. The capacity needed from existing resources has gone down by 54 MW due to decrease in NQC values.

3.3.8 Big Creek/Ventura Area

3.3.8.1 *Area Definition:*

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

Antelope #1 500/230 kV Transformer

Antelope #2 500/230 kV Transformer

Sylmar - Pardee 230 kV #1 and #2 Lines

Vincent - Pardee 230 kV #2 Line

Vincent - Santa Clara 230 kV Line

The substations that delineate the Big Creek/Ventura Area are:

Antelope 500 kV is out Antelope 230 kV is in

Antelope 500 kV is out Antelope 230 kV is in

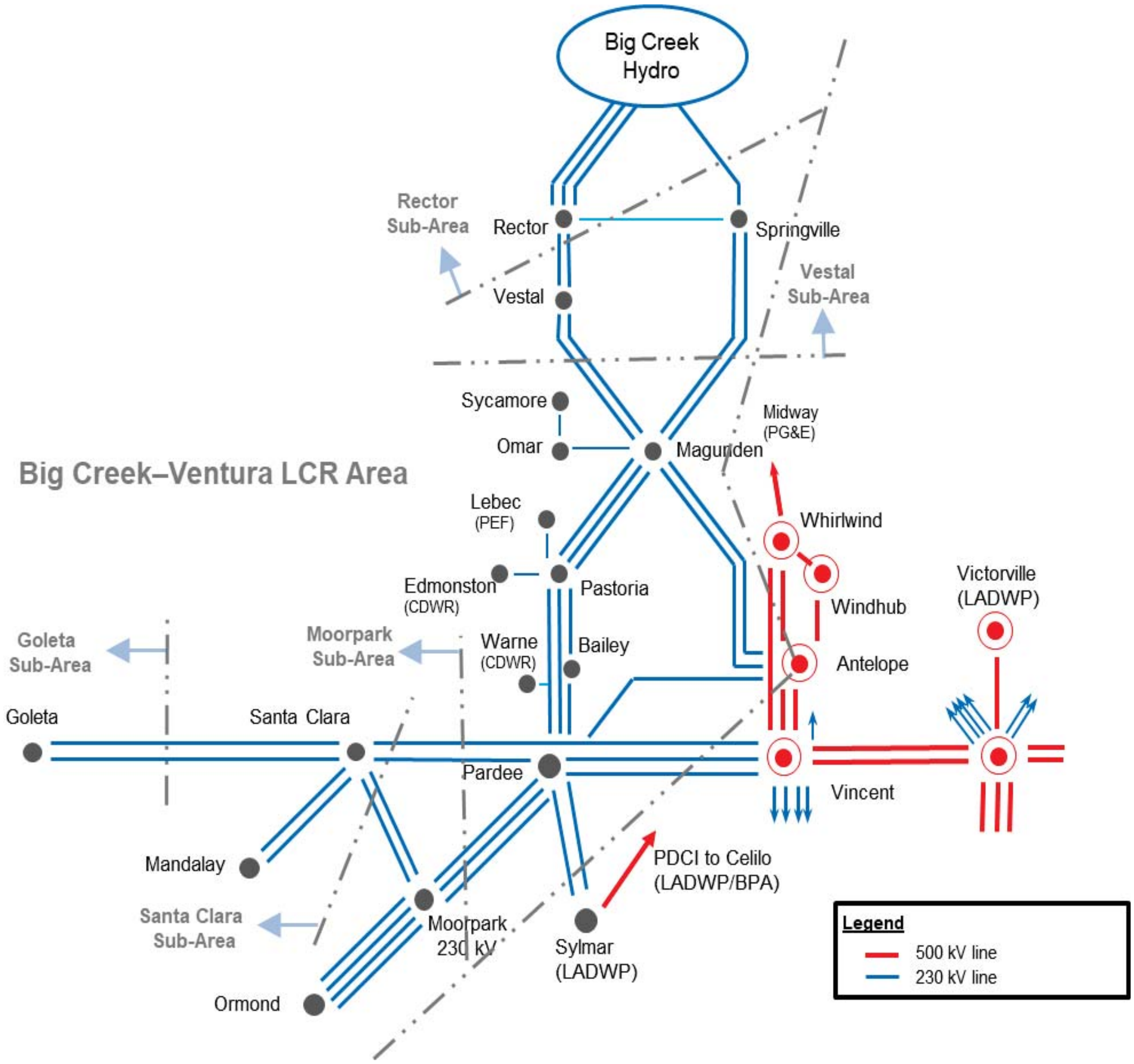
Sylmar is out Pardee is in

Vincent is out Pardee is in

Vincent is out Santa Clara is in

Big Creek/Ventura LCR Area Diagram

Figure 3.3-80 Big Creek/Ventura LCR Area



Big Creek/Ventura LCR Area Load and Resources

Table 3.3-69 provides the forecast load and resources in the Big Creek/Ventura LCR Area in 2021. The list of generators within the LCR area are provided in Attachment A and does not include new LTPP preferred resources or existing DR.

In year 2021 the estimated time of local area peak is 5:00 PM.

At the local area peak time the estimated, ISO-metered solar output is about 22.0%; therefore solar resources are dispatched at NQC.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-69 Big Creek/Ventura LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4435	Market, Net Seller	4147	4147
AAEE	-30	MUNI	312	312
Behind the meter DG	-294	QF	112	112
Net Load	4111	Solar	250	250
Transmission Losses	65	LTPP Preferred Resources (Battery)	207	207
Pumps	275	Existing 20-minute Demand Response	100	100
Load + Losses + Pumps	4451	Total	5128	5128

Approved transmission projects modeled:

Big Creek Corridor Rating Increase Project (completed).

Pardee-Moorpark No. 4 230 kV Transmission Project (ISD-12/31/2020)

3.3.8.2 *Rector Sub-area*

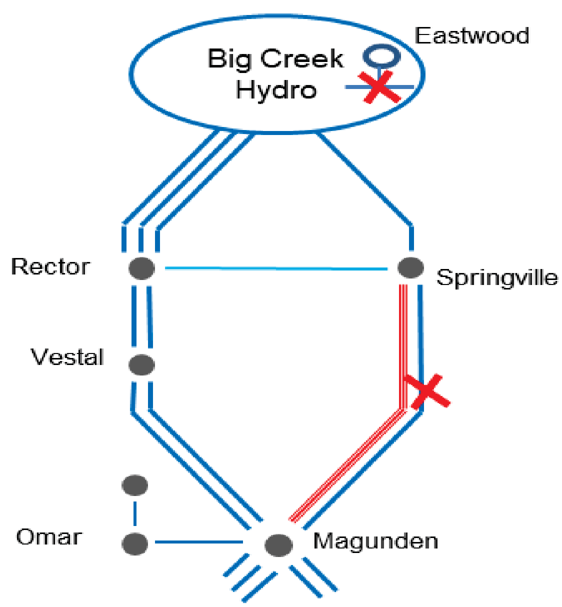
LCR need is satisfied by the need in the larger Vestal sub-area.

3.3.8.3 *Vestal Sub-area*

Vestal is a Sub-area of the Big Creek/Ventura LCR Area.

Vestal LCR Sub-area Diagram

Figure 3.3-81 Vestal LCR Sub-area



Vestal LCR Sub-area Load and Resources

Table 3.3-70 provides the forecast load and resources in Vestal LCR Sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

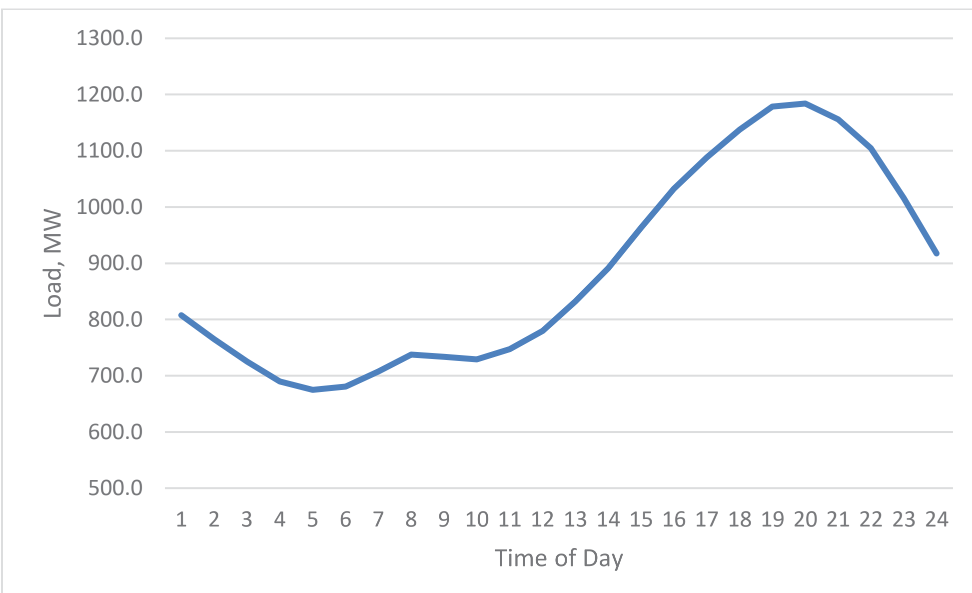
Table 3.3-70 Vestal LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	N/A	Market, Net Seller	1055	1055
AAEE	N/A	MUNI	0	0
Behind the meter DG	N/A	QF	22	22
Net Load	1184	Solar	9	9
Transmission Losses	27	LTPP Preferred Resources	0	0
Pumps	0	Existing 20-minute Demand Response	41	41
Load + Losses + Pumps	1211	Total	1127	1127

Vestal LCR Sub-area Hourly Profiles

Figure 3.3-82 illustrates the forecast 2021 profile for the summer peak day in the Vestal LCR sub-area.

Figure 3.3-82 Vestal LCR Sub-area 2021 Peak Day Forecast Profiles



Vestal LCR Sub-area Requirement

Table 3.3-71 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 304 MW.

Table 3.3-71 Vestal LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P3	Magunden-Springville #2 230 kV	Magunden-Springville #1 230 kV with Eastwood out of service	304

Effectiveness factors:

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

3.3.8.4 *Goleta Sub-area*

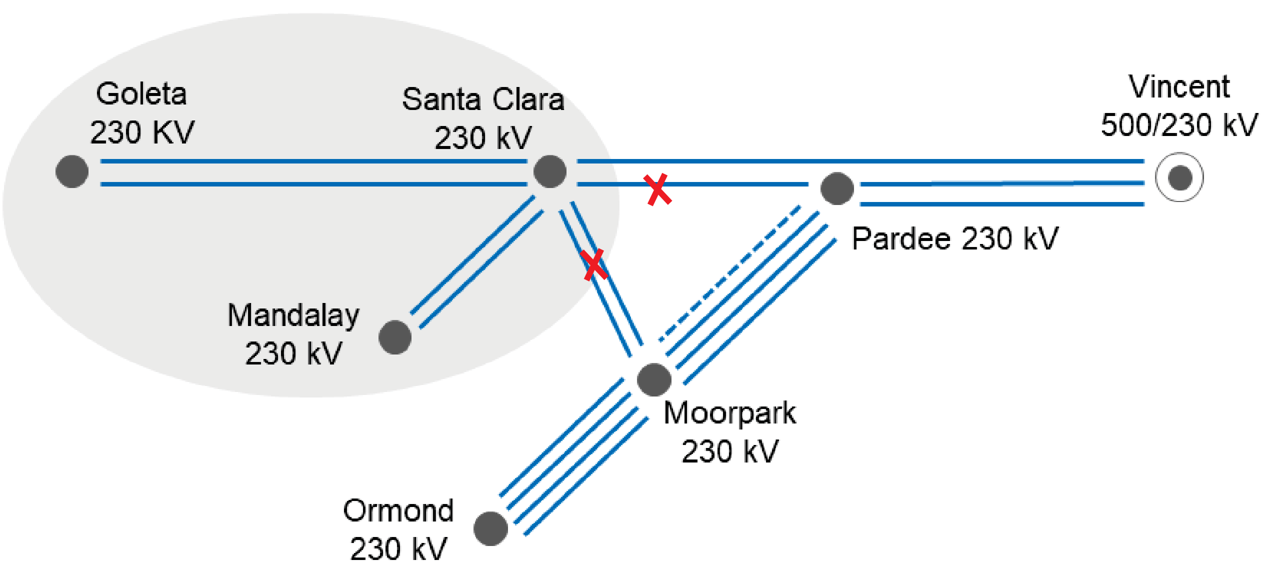
LCR need is satisfied by the need in the larger Santa Clara sub-area.

3.3.8.5 *Santa Clara Sub-area*

Santa Clara is a Sub-area of the Big Creek/Ventura LCR Area.

Santa Clara LCR Sub-area Diagram

Figure 3.3-83 Santa Clara LCR Sub-area



Santa Clara LCR Sub-area Load and Resources

Table 3.3-72 provides the forecast load and resources in Santa Clara LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

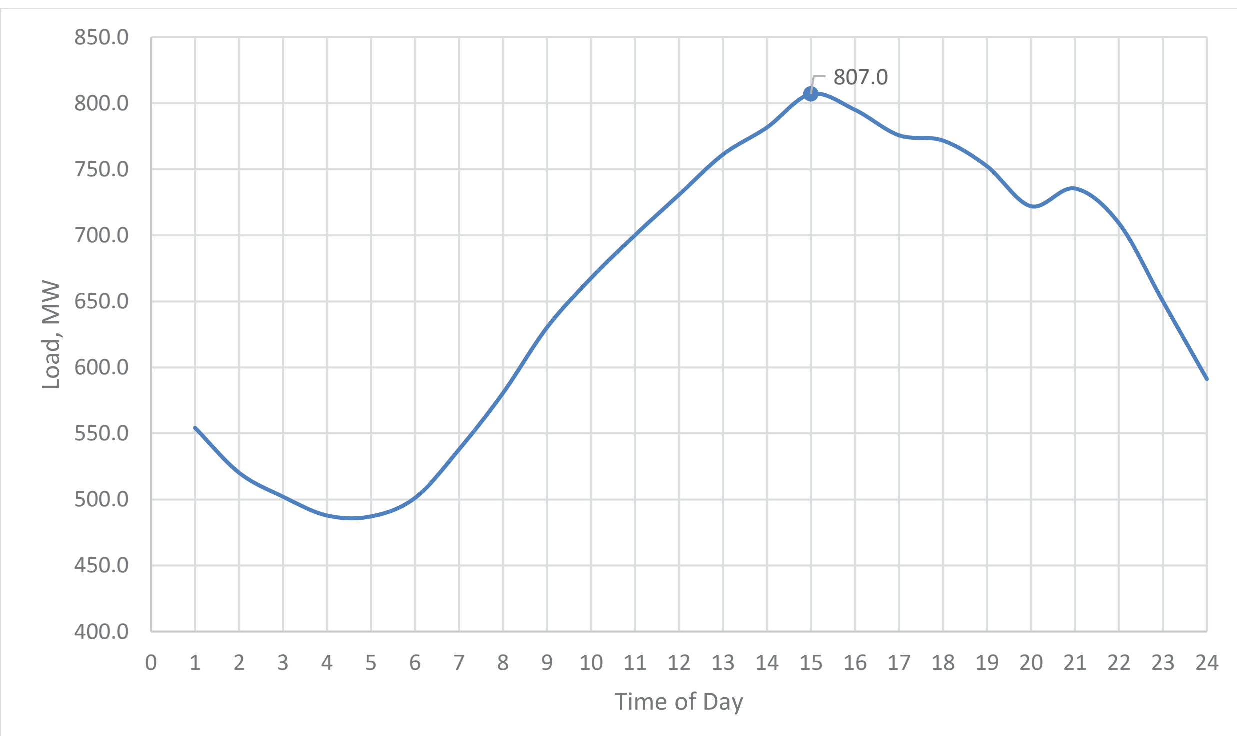
Table 3.3-72 Santa Clara LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	N/A	Market, Net Seller, Solar	156	156
AAEE	N/A	MUNI	0	0
Behind the meter DG	N/A	QF	84	84
Net Load	807	LTPP Preferred Resources (Battery)	195	195
Transmission Losses	2	Existing Demand Response	7	7
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	809	Total	442	442

Santa Clara LCR Sub-area Hourly Profiles

Figure 3.3-84 illustrates the forecast 2021 profile for the summer peak day in the Santa Clara LCR sub-area.

Figure 3.3-84 Santa Clara LCR Sub-area 2021 Peak Day Forecast Profiles



Santa Clara LCR Sub-area Requirement

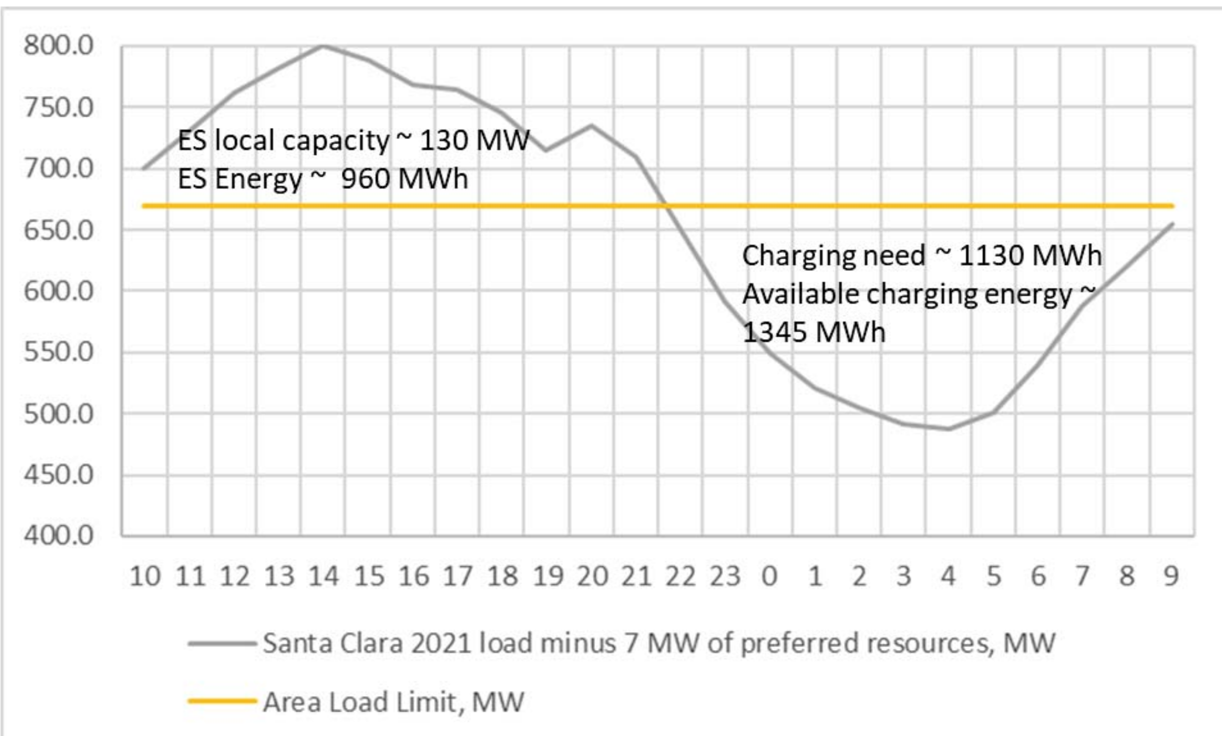
Table 3.3-73 identifies the sub-area requirements. The LCR requirement for Category P1 followed by P7 contingency is 229 MW.

Table 3.3-73 Santa Clara LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P1 + P7	Voltage collapse	Pardee - Santa Clara 230 kV followed by Moorpark - Santa Clara #1 & #2 230 kV	229

The area could be energy deficient if the resources selected to meet the LCR do not include sufficient conventional generation. Figure 3.3-98 shows an estimate of the maximum amount of energy storage that can count for local capacity in the area to avoid charging limitations.

Figure 3.3-85 Santa Clara Sub-area Stoage Analyisis



Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7550 and 7680 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.8.6 *Moorpark Sub-area*

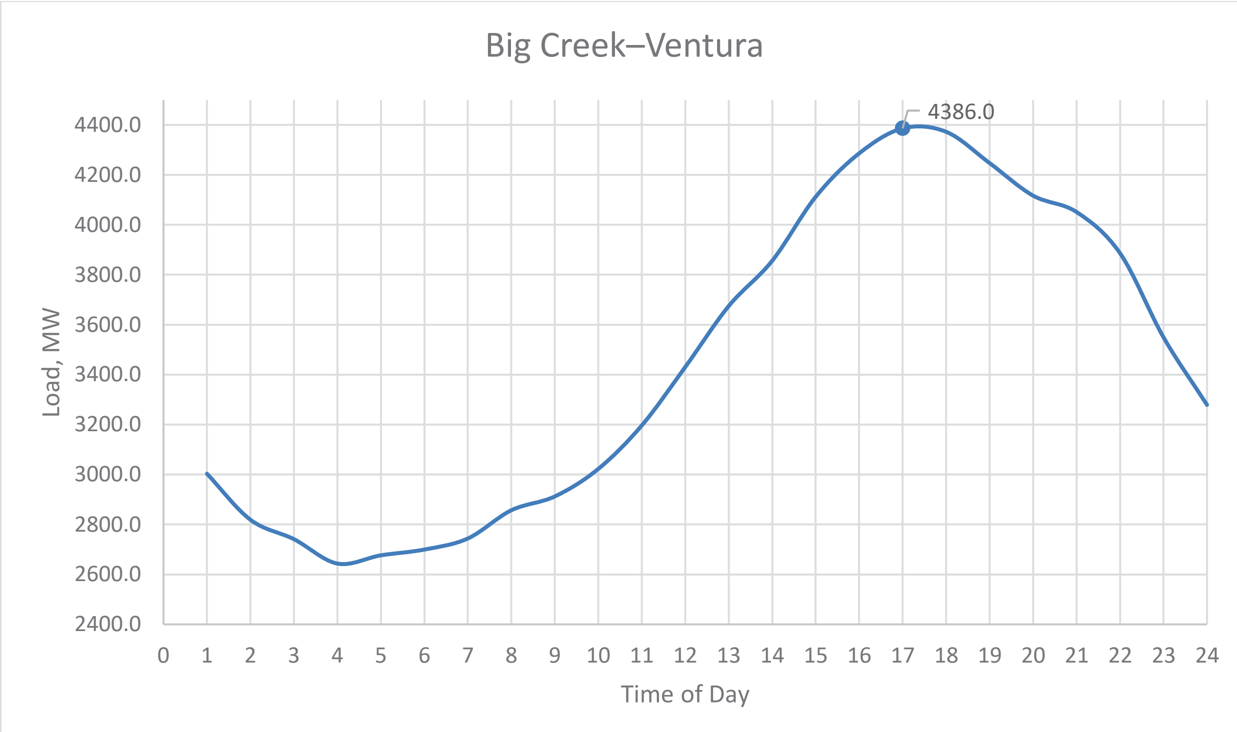
Moorpark sub-area has been eliminated due to the Pardee-Moorpark No. 4 230 kV Transmission Project.

3.3.8.7 *Big Creek/Ventura Overall*

Big Creek/Ventura LCR Sub-area Hourly Profiles

Figure 3.3-86 illustrates the forecast 2021 profile for the summer peak day in the Big Creek/Ventura LCR area.

Figure 3.3-86 Big Creek/Ventura LCR area 2021 Peak Day Forecast Profiles



Big Creek/Ventura LCR area Requirement

Table 3.3-74 identifies the area LCR requirements. The LCR requirement for Category P6 contingency is 2296 MW.

Table 3.3-74 Big Creek/Ventura LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	2296

Please see the 2025 LCR study report for the results of the analysis to estimate the maximum amount of energy storage that can be added in the Big Creek–Ventura area to displace gas-fired local capacity.

Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7500, 7510, 7550 and 7680 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to 2019 LCT study

Compared with the results for 2020, the load forecast is down by 570 MW and the LCR has decreased by 114 MW due to the decrease in the load forecast.

3.3.9 LA Basin Area

3.3.9.1 *Area Definition:*

The transmission tie lines into the LA Basin Area are:

San Onofre - San Luis Rey #1, #2, and #3 230 kV Lines

San Onofre - Talega #1 & #2 230 kV Lines

Lugo - Mira Loma #2 & #3 500 kV Lines

Lugo - Rancho Vista #1 500 kV Line

Vincent – Mira Loma 500 kV Line

Sylmar - Eagle Rock 230 kV Line

Sylmar - Gould 230 kV Line

Vincent - Mesa #1 & #2 230 kV Lines

Vincent - Rio Hondo #1 & #2 230 kV Lines

Devers - Red Bluff 500 kV #1 and #2 Lines

Mirage – Coachella Valley # 1 230 kV Line

Mirage - Ramon # 1 230 kV Line

Mirage - Julian Hinds 230 kV Line

The substations that delineate the LA Basin Area are:

San Onofre is in San Luis Rey is out

San Onofre is in Talega is out

Mira Loma is in Lugo is out

Rancho Vista is in Lugo is out

Eagle Rock is in Sylmar is out

Gould is in Sylmar is out

Mira Loma is in Vincent is out

Mesa is in Vincent is out

Rio Hondo is in Vincent is out

Devers is in Red Bluff is out

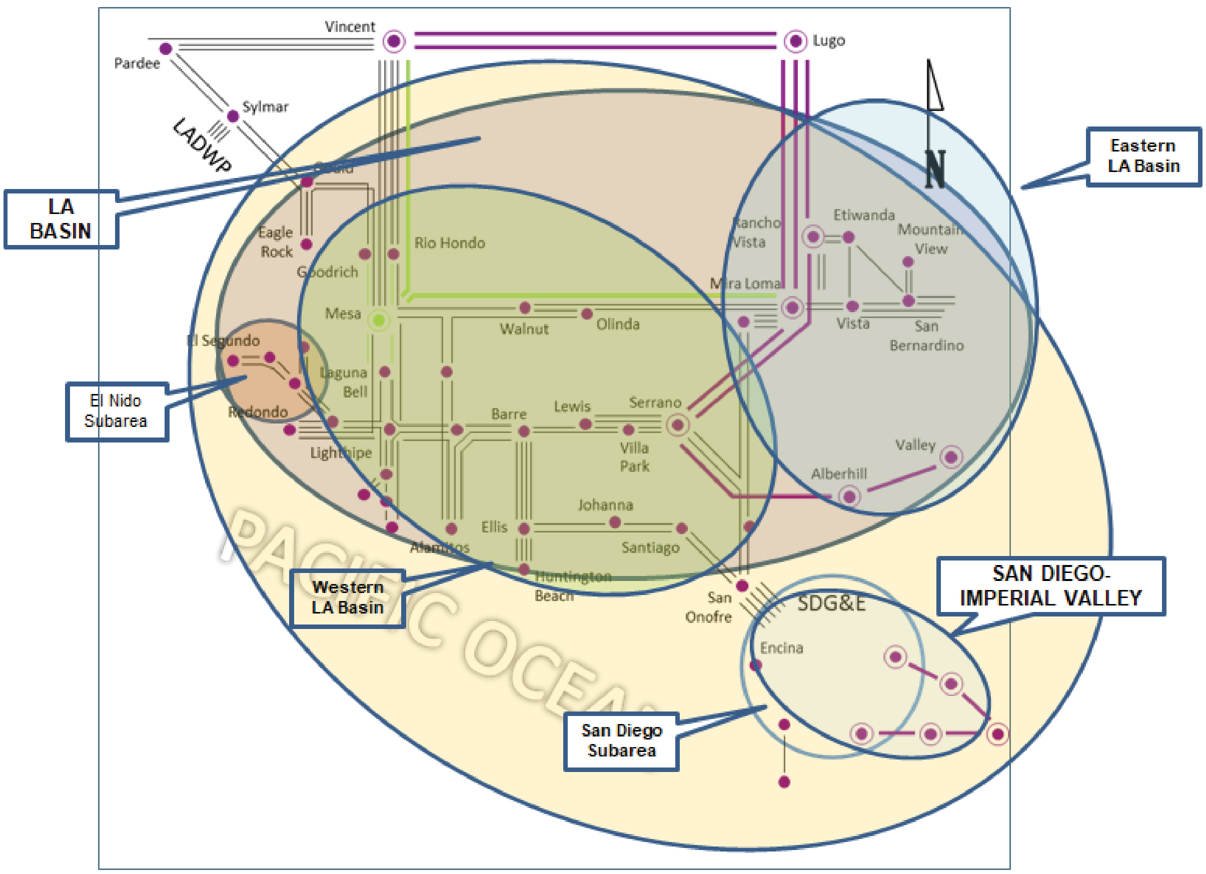
Mirage is in Coachella Valley is out

Mirage is in Ramon is out

Mirage is in Julian Hinds is out

LA Basin LCR Area Diagram

Figure 3.3-87 LA Basin LCR Area



LA Basin LCR Area Load and Resources

Table 3.3-75 provides the forecast load and resources in the LA Basin LCR Area in 2021. The list of generators within the LCR area are provided in Attachment A and does not include new LTPP preferred resources or DR.

In year 2021 the estimated time of local area peak is 5:00 PM (PDT) based on the CEC hourly forecast for the 2020-2030 California Energy Demand Revised Forecast.

At the local area peak time the estimated, ISO metered, solar output is 14%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-75 LA Basin LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	20234	Market, Net Seller, Wind, Battery	7838	7838
AAEE + AAPV	-158	MUNI	1056	1056
Behind the meter DG	-1450	QF	141	141
Net Load	18626	LTPP Preferred Resources (BTM BESS, EE, DR, PV)	331	331
Transmission Losses	284	Existing Demand Response	287	287
Pumps	20	Solar	11	11
Load + Losses + Pumps	18930	Total	9664	9664

Approved new transmission and resource projects modeled:

Mesa Loop-In Project (230 kV portion)

Alamitos repowering

Huntington Beach repowering

Stanton Energy Reliability Center (98 MW)

Alamitos battery energy storage system (100 MW/400MWh)

3.3.9.2 *El Nido Sub-area*

El Nido is a Sub-area of the LA Basin LCR Area.

El Nido LCR Sub-area Diagram

Please refer to Figure 3.3-87 above.

El Nido LCR Sub-area Load and Resources

Table 3.3-76 provides the forecast load and resources in El Nido LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-76 El Nido LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1049	Market, Net Seller	534	534
AAEE	-13	MUNI	3	3
Behind the meter DG	-31	QF	0	0
Net Load	1005	LTPP Preferred Resources	23	23
Transmission Losses	2	Existing Demand Response	9	9
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	1007	Total	569	569

El Nido LCR Sub-area Hourly Profiles

Figure 3.3-88 illustrates the forecast 2021 profile for the summer peak day in the El Nido LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources.

Figure 3.3-89 and Figure 3.3-90 illustrate that load serving capability is higher by retaining some local gas generation in the sub-area, some amount of energy storage for the overall area can be accommodated and is limted by the charging capability under the extended transmission contingency condition. For this case, an estimated 250 MW and 2000 MWh of energy storage can be accommodated from the charging limitation perspective as shown on Figure 3.3-90.

Figure 3.3-88 El Nido LCR Sub-area 2021 Peak Day Forecast Profiles

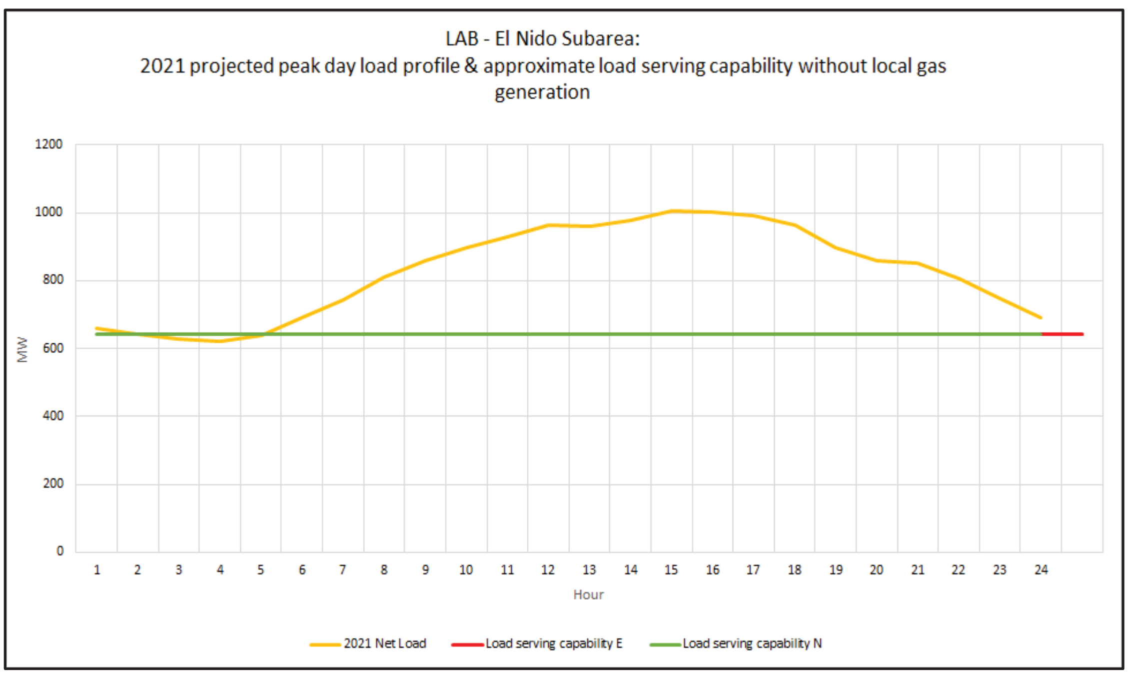


Figure 3.3-89 El Nido LCR Sub-area 2021 Peak Day Forecast Profiles with Higher Load Serving Capability

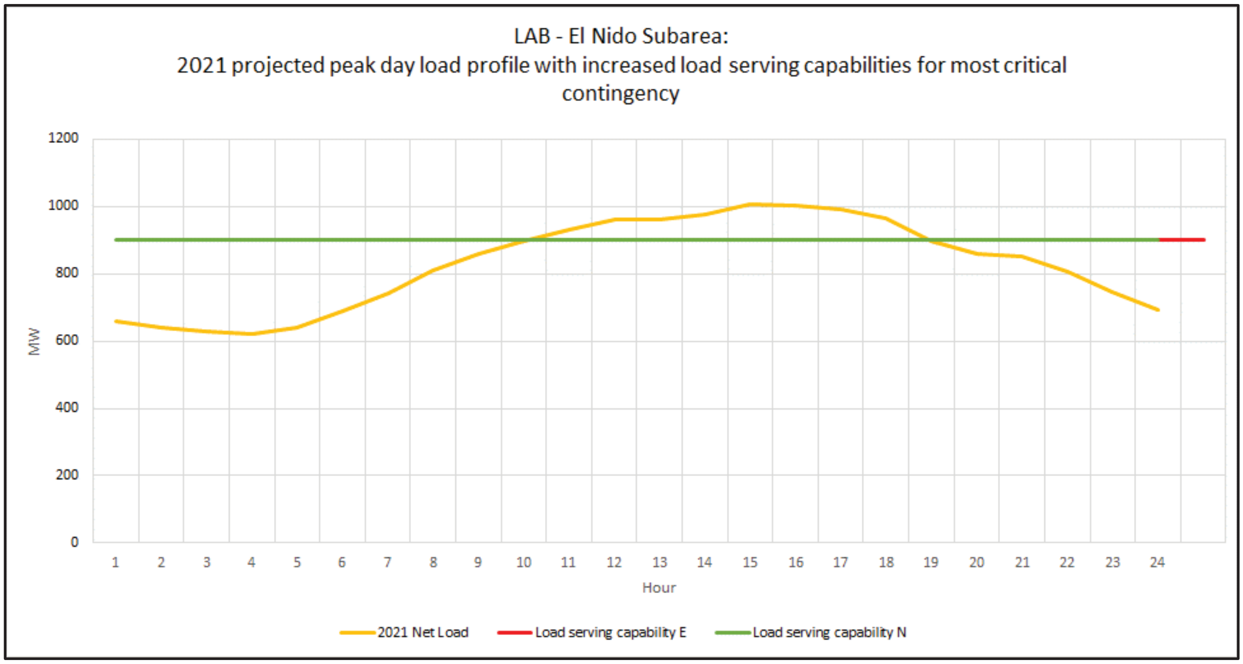
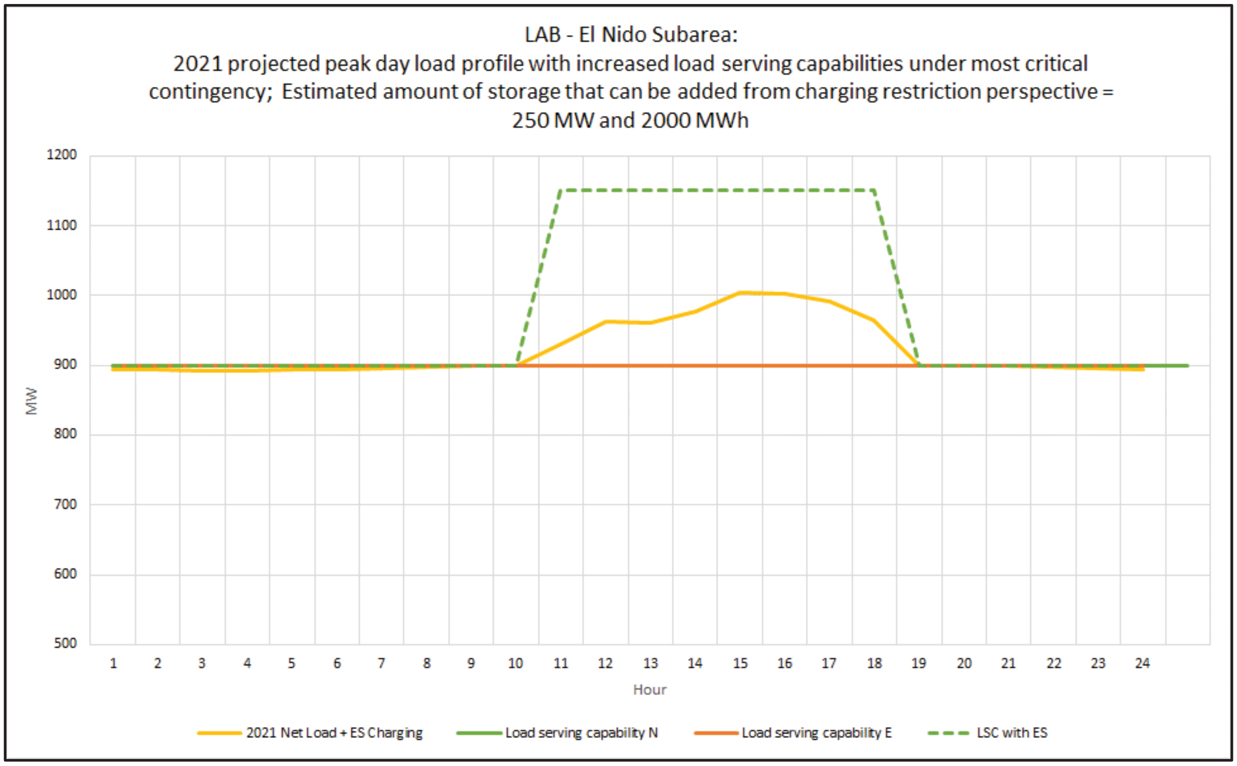


Figure 3.3-90 El Nido LCR Sub-area 2021 Estimated Amount of Storage that Can Be Added With Higher Load Serving Capability



El Nido LCR Sub-area Requirement

Table 3.3-77 identifies the sub-area requirements. The LCR requirement for Category P7 contingency is 229 MW. The LCR need increases over 2020 requirements due to reallocation of higher substation loads in the El Nido subarea.

Table 3.3-77 El Nido LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P7	La Fresa - La Cienega 230 kV	La Fresa – El Nido #3 & 4 230 kV lines	394

Effectiveness factors:

All units within the El Nido Sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7630 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.9.3 *Western LA Basin Sub-area*

Western LA Basin is a sub-area of the LA Basin LCR Area.

Western LA Basin LCR Sub-area Diagram

Please refer to Figure 3.3-87 above.

Western LA Basin LCR Sub-area Load and Resources

Table 3.3-78 provides the forecast load and resources in Western LA Basin LCR Sub-area in 2021. The list of generators within the LCR Sub-area are provided in Attachment A.

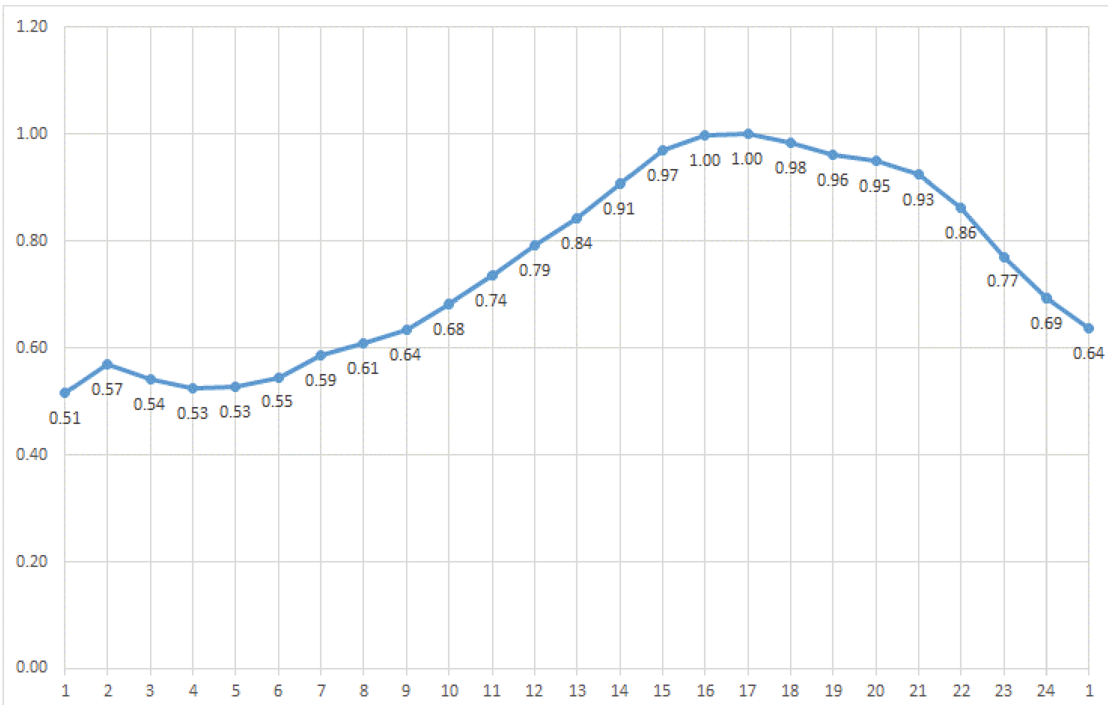
Table 3.3-78 Western LA Basin Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	11833	Market, Net Seller, Battery, Solar	5456	5456
AAEE	-135	MUNI	584	584
Behind the meter DG	-464	QF	58	58
Net Load	11234	LTPP Preferred Resources	317	317
Transmission Losses	169	Existing Demand Response	161	161
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	11403	Total	6576	6576

Western LA Basin LCR Sub-area Hourly Profiles

Figure 3.3-91 illustrates the forecast 2021 profile for the summer peak day in the Western LA Basin LCR sub-area. Due to the interaction between Western and Eastern LA Basin, as well as with the San Diego-Imperial Valley areas, the load profile with load serving capability, and the energy storage addition based on its charging capability are evaluated and included for the overall LA Basin.

Figure 3.3-91 Western LA Basin LCR Sub-area 2021 Peak Day Forecast Profiles



Western LA Basin LCR Sub-area Requirement

Table 3.3-79 identifies the Western LA Basin 2021 LCR sub-area requirements. The 2021 LCR need is lower than 2020 LCR need due to the Mesa 230 kV loop-in portion of the Mesa Loop-In Project is completed, bringing new power sources to Mesa substation. The 230 kV bus tie breaker is operated in the closed position (while 500kV portion is constructed) to help mitigate loading concern. As well as the CEC's demand forecast for Cities of Vernon and Anaheim being lower compared to 2020 LCR study.

Table 3.3-79 Western LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P3	Barre-Lewis 230 kV line	G-1 of new Huntington Beach combined cycle plant, system readjusted, followed by Barre-Villa Park 230 kV line outage	3303

Sensitvity of LCR needs with the Use of Proposed OTC Extension Units:

The ISO evaluated for the sensitivity assessment the LCR need for the western LA Basin without the use of the proposed OTC extension units to determine the additional requirements due to the use of less effective generating units. The assessment resulted in an additional 54 MW of LCR need, for a total of 3249 MW for the western LA Basin subarea.

Effectiveness factors:

See Attachment B - Table titled 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 other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area 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, these effectiveness factors may not be the best indicator towards informed procurement.

3.3.9.4 *West of Devers Sub-area*

West of Devers is a Sub-area of the LA Basin LCR Area. The 2020 LCT study identified that the West of Devers sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.3.9.5 *Valley-Devers Sub-area*

Valley-Devers is a Sub-area of the LA Basin LCR Area. The 2020 LCT study identified that the Valley-Devers sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.3.9.6 *Valley Sub-area*

Valley is a Sub-area of the LA Basin LCR Area. The 2020 LCT study identified that the Valley sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.3.9.7 *Eastern LA Basin Sub-area*

Eastern LA Basin is a sub-area of the LA Basin LCR Area.

Eastern LA Basin LCR Sub-area Diagram

Please refer to Figure 3.3-87 above.

Eastern LA Basin LCR Sub-area Load and Resources

Table 3.3-80 provides the forecast load and resources in Eastern LA Basin LCR sub-area in 2020. The list of generators within the LCR sub-area are provided in Attachment A.

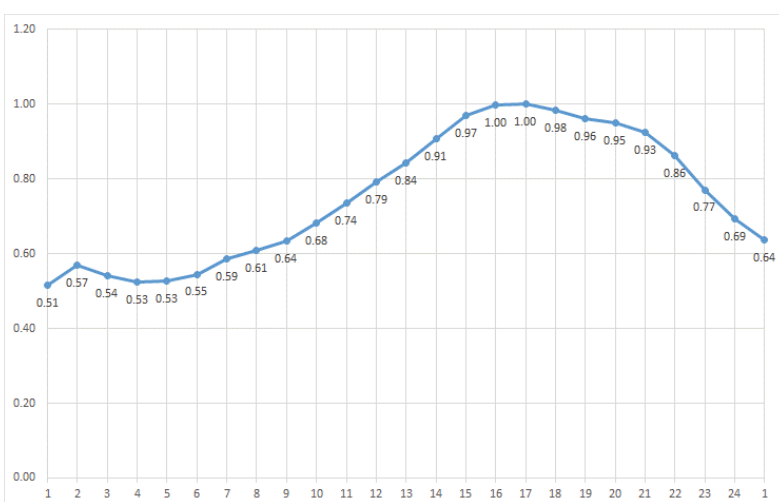
Table 3.3-80 Eastern LA Basin Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	7945	Market, Net Seller, battery, Wind	2384	2384
AAEE	-61	MUNI	472	472
Behind the meter DG	-493	QF	83	83
Net Load	7391	LTPP Preferred Resources	0	0
Transmission Losses	111	Existing Demand Response	126	126
Pumps	20	Solar	9	9
Load + Losses + Pumps	7522	Total	3074	3074

Eastern LA Basin LCR Sub-area Hourly Profiles

Figure 3.3-92 illustrates the forecast 2021 profile for the summer peak day in the Eastern LA Basin LCR sub-area. Due to the interaction between Western and Eastern LA Basin, as well as with the San Diego-Imperial Valley areas, the load profile with load serving capability, and the energy storage addition based on its charging capability are evaluated and included for the overall LA Basin.

Figure 3.3-92 Eastern LA Basin LCR Sub-area 2021 Peak Day Forecast Profiles



Eastern LA Basin LCR Sub-area Requirement

Table 3.3-81 identifies the sub-area LCR requirements. The LCR need for the Eastern LA Basin is higher than the 2020 LCR need due to reallocation of CEC forecast among bus loads at some locations in the Eastern LA Basin and because imports are higher due to lower availability of internal generation (lower NQC values) for solar and wind generation in SCE and SDG&E areas).

Table 3.3-81 Eastern LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P1+P7	Post-transient voltage stability	Serrano - Valley 500 kV line, followed by Devers – Red Bluff 500 kV #1 and 2 lines	2867

Effectiveness factors:

All units within the Eastern LA Basin Sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7580, 7590, 7630 and 7750 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.9.8 *LA Basin Overall*

LA Basin LCR Sub-area Hourly Profiles

Figure 3.3-93 illustrates the forecast 2021 profile for the summer peak day in the LA Basin LCR area with the Category P1 normal and emergengy load serving capabilities without local gas resources.

Figure 3.3-94 and Figure 3.3-95 illustrate that load serving capability is higher by retaining some local gas generation that was procured as part of long term procurement plan and those with long-term contract for the LA Basin, some amount of energy storage for the overall area can be accommodated and is limted by the charging capability under the extended transmission contingency condition. Table 3.3-82 provides a summary of the estimated amount of energy storage that can be accommodated from the charging limitation perspective for the sub-areas and the overall LCR area.

Figure 3.3-93 LA Basin LCR area 2021 Peak Day Forecast Profiles and Load Serving Capability Without Local Gas Generation

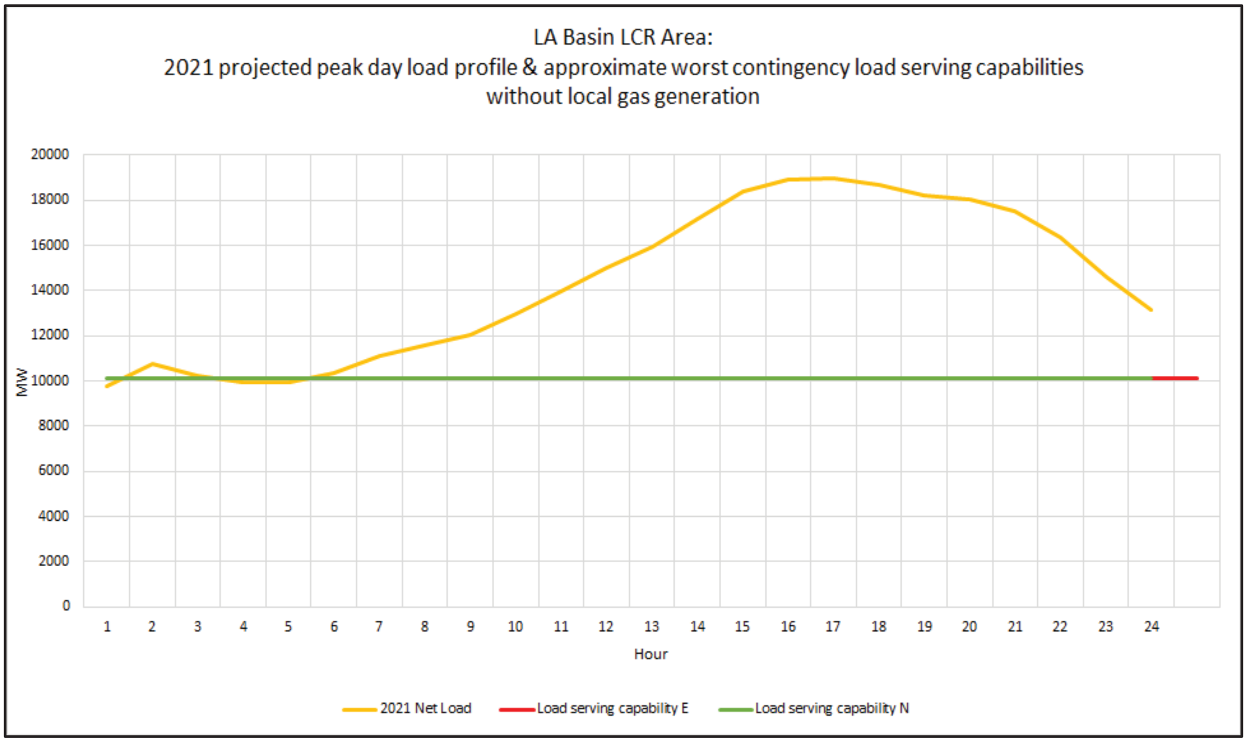


Figure 3.3-94 LA Basin 2021 Peak Day Forecast Profiles with Higher Load Serving Capability

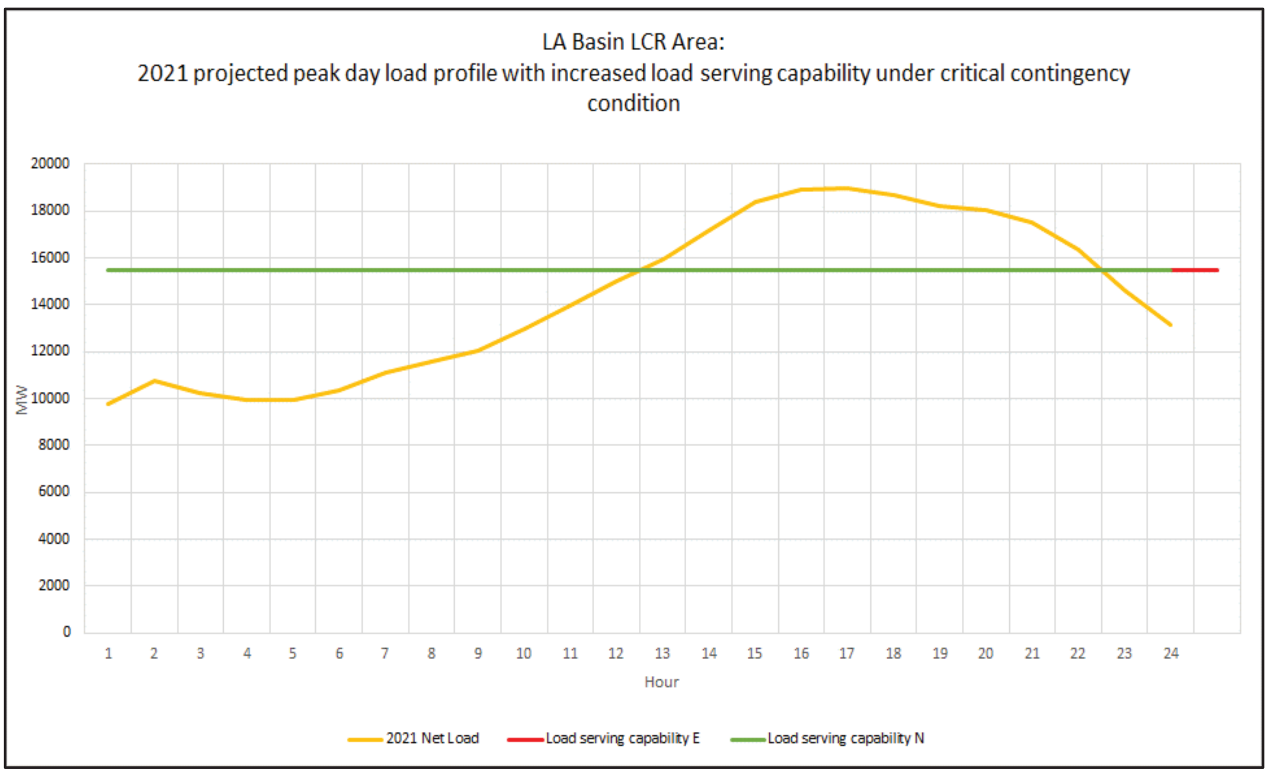
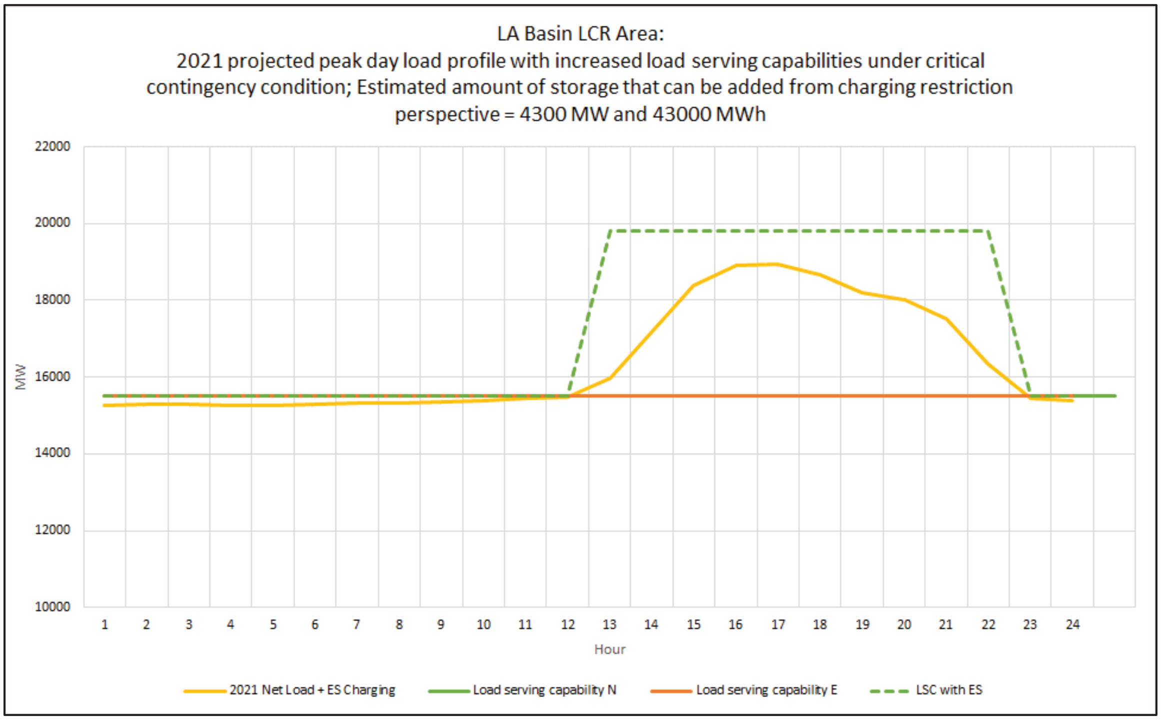


Figure 3.3-95 LA Basin Area 2021 Estimated Amount of Storage that Can Be Added With Higher Load Serving Capability



The following is a summary of estimated amount of storage for the sub-areas and the overall area based on maximum charging capability perspective. Due to non-linearity of power system and the various critical contingencies and load shapes for each sub-area and the overall area, it is noted that the estimated maximum amount of storage for the sub-areas many not add up to be sum of the overall area. The estimated maximum amount of storage for the LCR area is the amount listed in the last row in the table.

Table 3.3-82 Estimated LA Basin Subareas and Overall Area Energy Storage Capacity and Energy Based on Maximum Charging Capability Perspective

Area/Sub-area	Estimated Energy Storage Maximum Capacity (MW)	Estimated Energy Storage Maximum Energy (MWh)
El Nido sub-area	250	2000
Western LA Basin sub-area	2600	26000
Eastern LA Basin sub-area	1700	17000
Overall LA Basin area	4300	43000

LA Basin LCR area Requirement

Table 3.3-83 identifies the area requirements. The LCR requirement for a P3 category contingency is 6127 MW.

Table 3.3-83 LA Basin LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P3	Imperial Valley – El Centro 230 kV Line (S-Line	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500 kV line (N-1)	6127
2021	Second Limit	Sum of Western and Eastern LA Basin LCR needs			6116

Explanation regarding coordination between LA Basin and San Diego-Imperial Valley:

To arrive at the above local capacity requirement, the ISO performed the study for the LA Basin in coordination with the San Diego-Imperial Valley area as these two areas are electrically interdependent due to retirement of San Onofre Nuclear Generating Station (SONGS) and other once-through-cooled generation in the area. For the LA Basin study, a study case with its peak load was developed, with the San Diego load modeled at the time of the LA Basin peak load (5 p.m. on September 7, 2021 per the CEC hourly demand forecast).

Effectiveness factors:

See Attachment B - Table titled LA Basin.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7550, 7570, 7580, 7590, 7630, and 7750 posted at: http://www.caiso.com/Documents/2210Z.pdf

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

Changes compared to 2020 LCT study

Compared with 2020, the CEC load forecast is lower by 331 MW and the LCR needs have decreased by 1237 MW. Significant LCR reduction can be attributed to the implementation of the loop-in of the 230 kV portion of the Mesa Loop-In Project, with the Mesa 230 kV bus tie circuit breaker operating in the closed position while the 500 kV loop-in portion is under construction as well as lower demand forecast for the Cities of Vernon and Anaheim in the western LA Basin sub-area.

3.3.10 San Diego-Imperial Valley Area

3.3.10.1 *Area Definition:*

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

Imperial Valley – North Gila 500 kV Line

Otay Mesa – Tijuana 230 kV Line

San Onofre - San Luis Rey #1 230 kV Line

San Onofre - San Luis Rey #2 230 kV Line

San Onofre - San Luis Rey #3 230 kV Line

San Onofre – Talega 230 kV #1 and #2 Lines

Imperial Valley – El Centro 230 kV Line

Imperial Valley – La Rosita 230 kV Line

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

Imperial Valley is in North Gila is out

Otay Mesa is in Tijuana is out

San Onofre is out San Luis Rey is in

San Onofre is out San Luis Rey is in

San Onofre is out San Luis Rey is in

San Onofre is out Talega is in

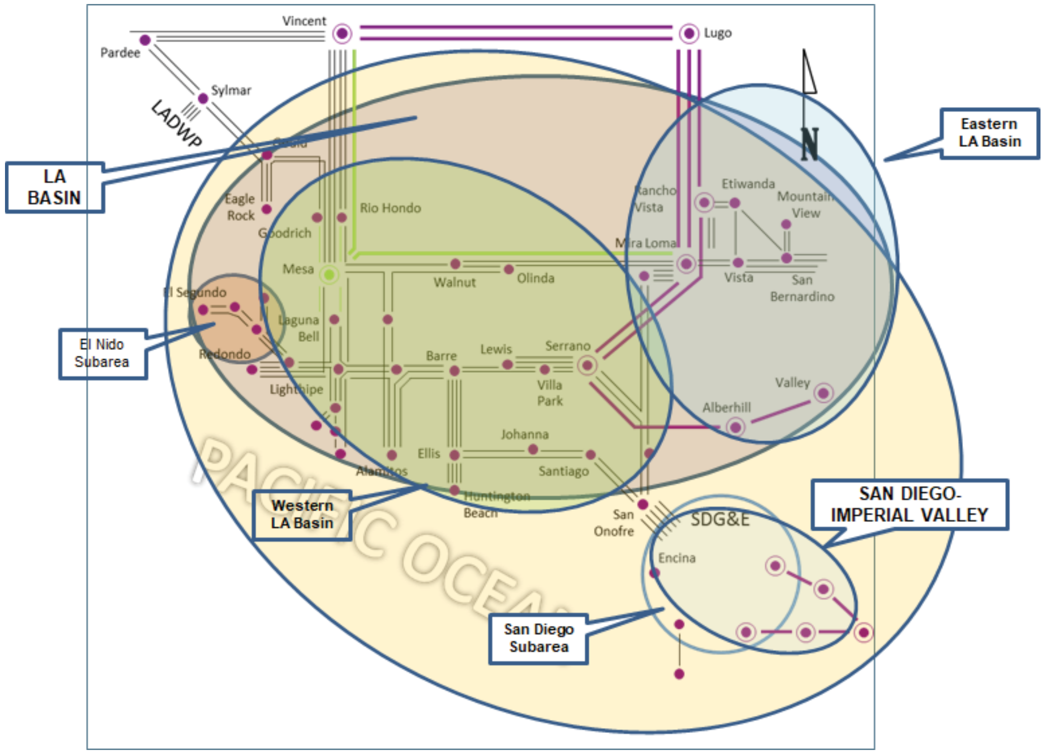
San Onofre is out Capistrano is in

Imperial Valley is in El Centro is out

Imperial Valley is in La Rosita is out

San Diego-Imperial Valley LCR Area Diagram

Figure 3.3-96 San Diego-Imperial Valley LCR Area



San Diego-Imperial Valley LCR Area Load and Resources

Table 3.3-84 provides the forecast load and resources in the San Diego-Imperial Valley LCR Area in 2021. The list of generators within the LCR area are provided in Attachment A.

In year 2021 the estimated time of local area peak is 8:00 PM (PDT).

At the local area peak time the estimated, ISO metered, solar output is 0.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-84 San Diego-Imperial Valley LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4443	Market, Net Seller, Battery, Wind	3996	3996
AAEE	-28	Solar (production is “0” at 20:00 hr.)	356	0
Behind the meter DG	0	QF	2	2
Net Load	4415	LTPP Preferred Resources	0	0
Transmission Losses	108	Existing Demand Response	7	7
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	4523	Total	4361	4005

Approved transmission projects modeled:

Ocean Ranch 69 kV substation

Mesa Height TL600 Loop-in

TL6906 Mesa Rim Rearrangement

Upgrade Bernardo - Rancho Carmel 69 kV line

2nd Miguel–Bay Boulevard 230 kV line

Suncrest SVC project

By-passing 500 kV series capacitor banks on the Southwest Powerlink and Sunrise Powerlink

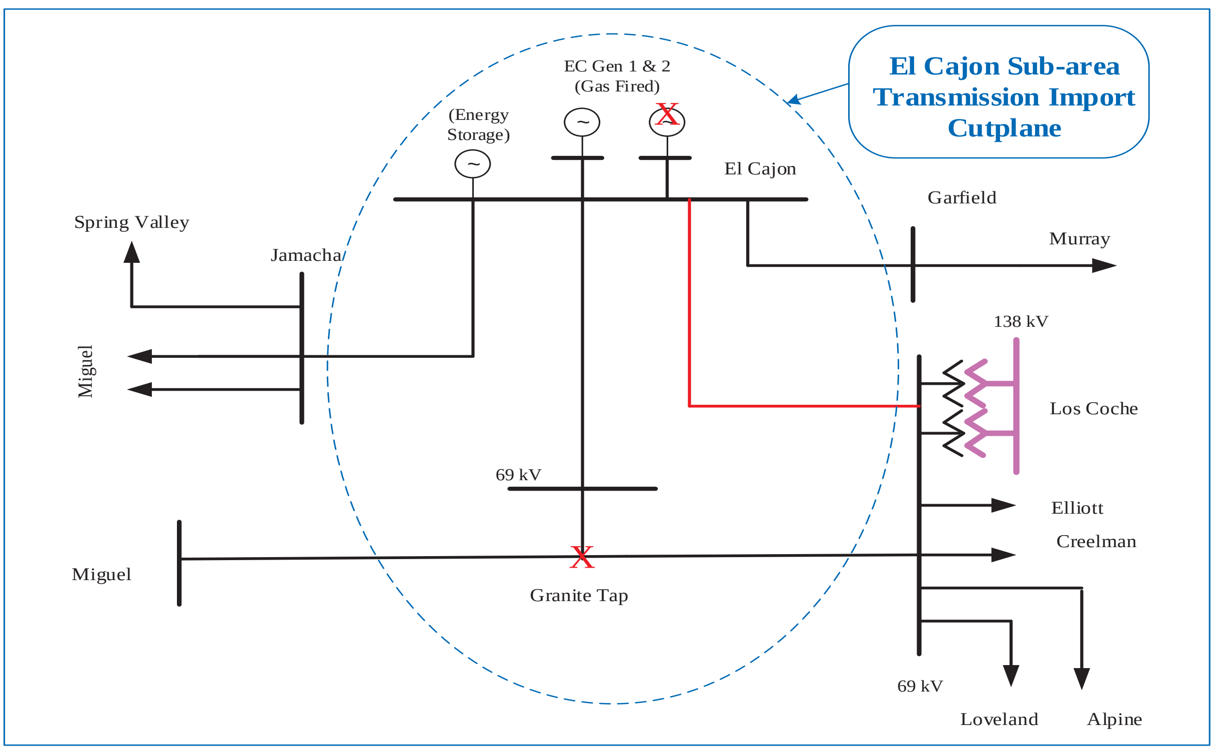
2nd Poway–Pomerado 69 kV line

3.3.10.2 *El Cajon Sub-area*

El Cajon is Sub-area of the San Diego-Imperial Valley LCR Area.

El Cajon LCR Sub-area Diagram

Figure 3.3-97 El Cajon LCR Sub-area



El Cajon LCR Sub-area Load and Resources

Table 3.3-85 provides the forecast load and resources in El Cajon LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-85 El Cajon LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	167	Market, Net Seller, Battery	101	101
AAEE	-2	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	165	LTPP Preferred Resources	0	0
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	167	Total	101	101

El Cajon LCR Sub-area Hourly Profiles

Figure 3.3-98 illustrates the 2021 annual load forecast profile in the El Cajon LCR sub-area and the Category P1 (L-1 Contingency) transmission capability without gas generation. Figure 3.3-99 illustrates the 2021 daily load profile forecast for the peak day for the sub-area along with the load serving capabilities. The illustration also includes an estimate of 48/432 MW/MWh energy storage that could be added in this local area from charging restriction perspective, which includes the existing 7.5 MW of energy storage at El Cajon, in order to displace the LCR requirement for gas generation, assuming the biggest energy storage unit is 8/72 MW/MWh.

Figure 3.3-98 El Cajon LCR Sub-area 2021 Annual Load Forecast Profiles

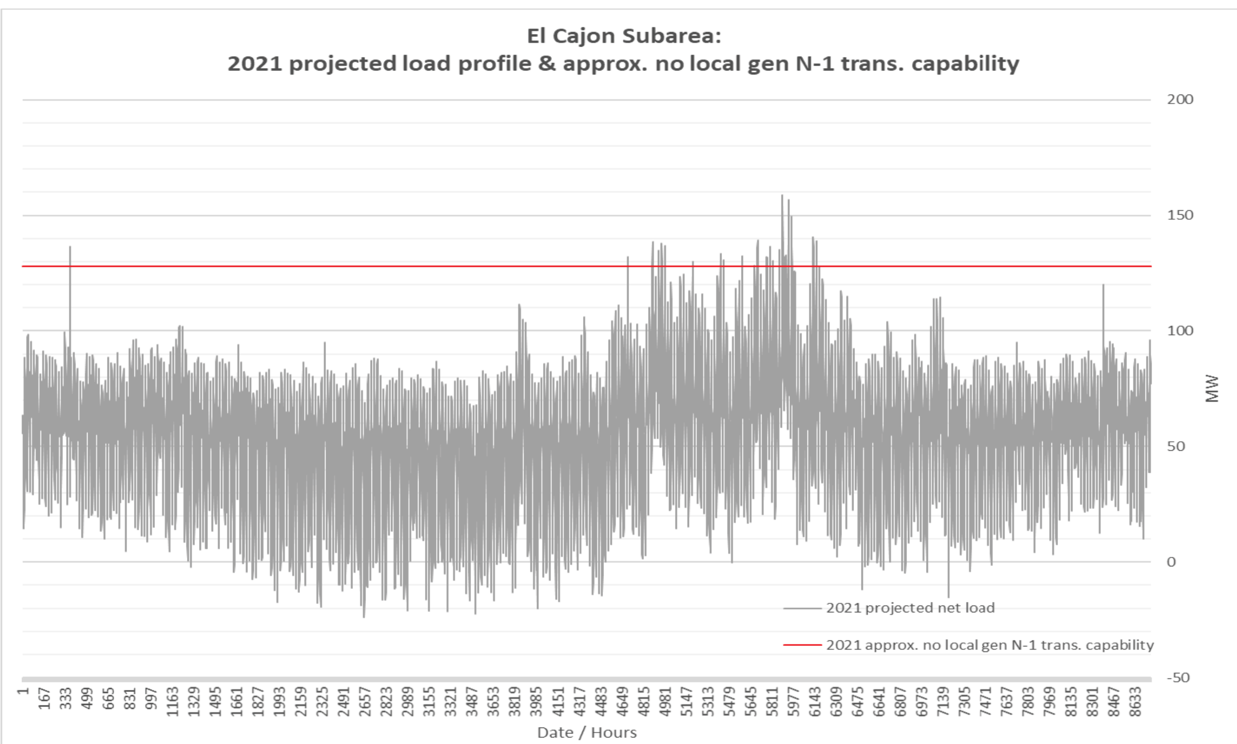
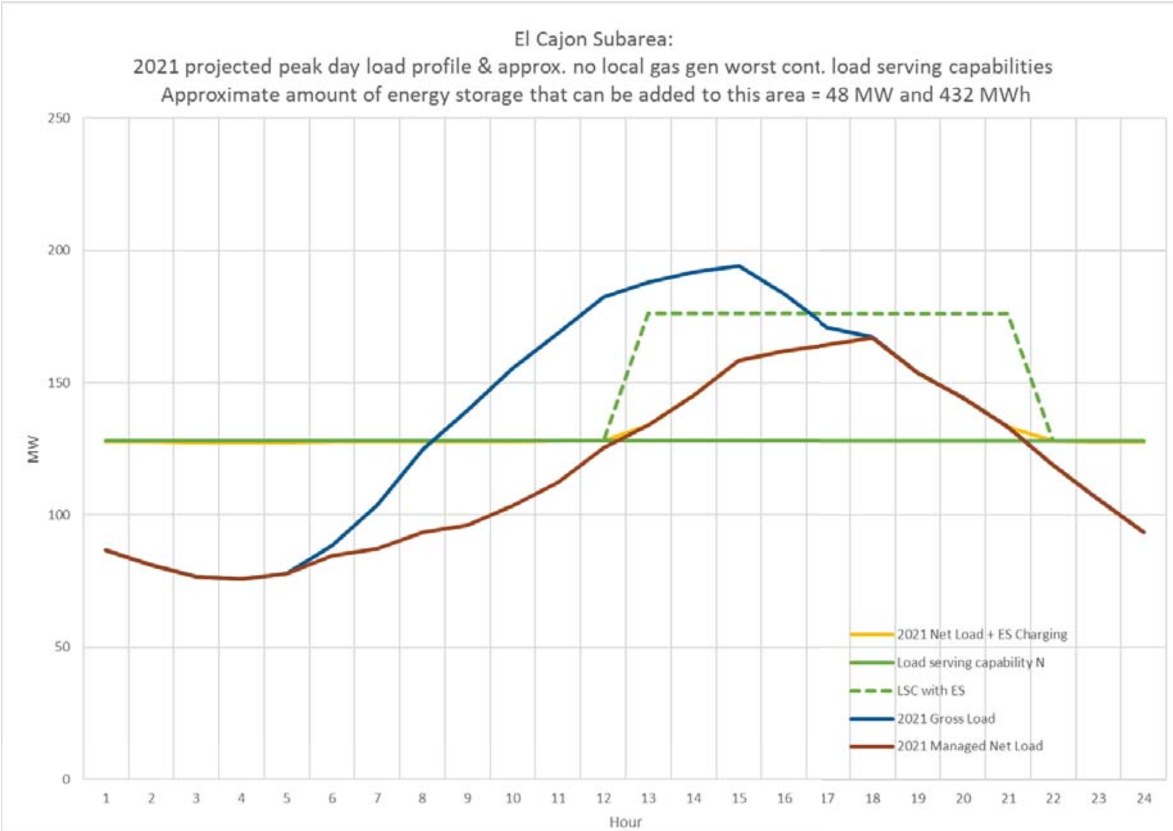


Figure 3.3-99 El Cajon LCR Sub-area 2021 Peak Day Forecast Profiles



El Cajon LCR Sub-area Requirement

Table 3.3-86 identifies the sub-area 2021 LCR requirements. The Category P3 (Single Contingency) LCR requirement is 92 MW.

Table 3.3-86 El Cajon LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P3	El Cajon – Los Coches 69 kV Line	El Cajon unit out of service followed by TL632 Granite–Los Coches–Miguel 69 kV Line	92

Effectiveness factors:

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

3.3.10.3 *Esco Sub-area*

Esco sub-area has been eliminated due to change in LCR criteria.

3.3.10.4 *Pala Inner Sub-area*

Pala Inner sub-area has been eliminated due to change in LCR criteria.

3.3.10.5 *Pala Outer Sub-area*

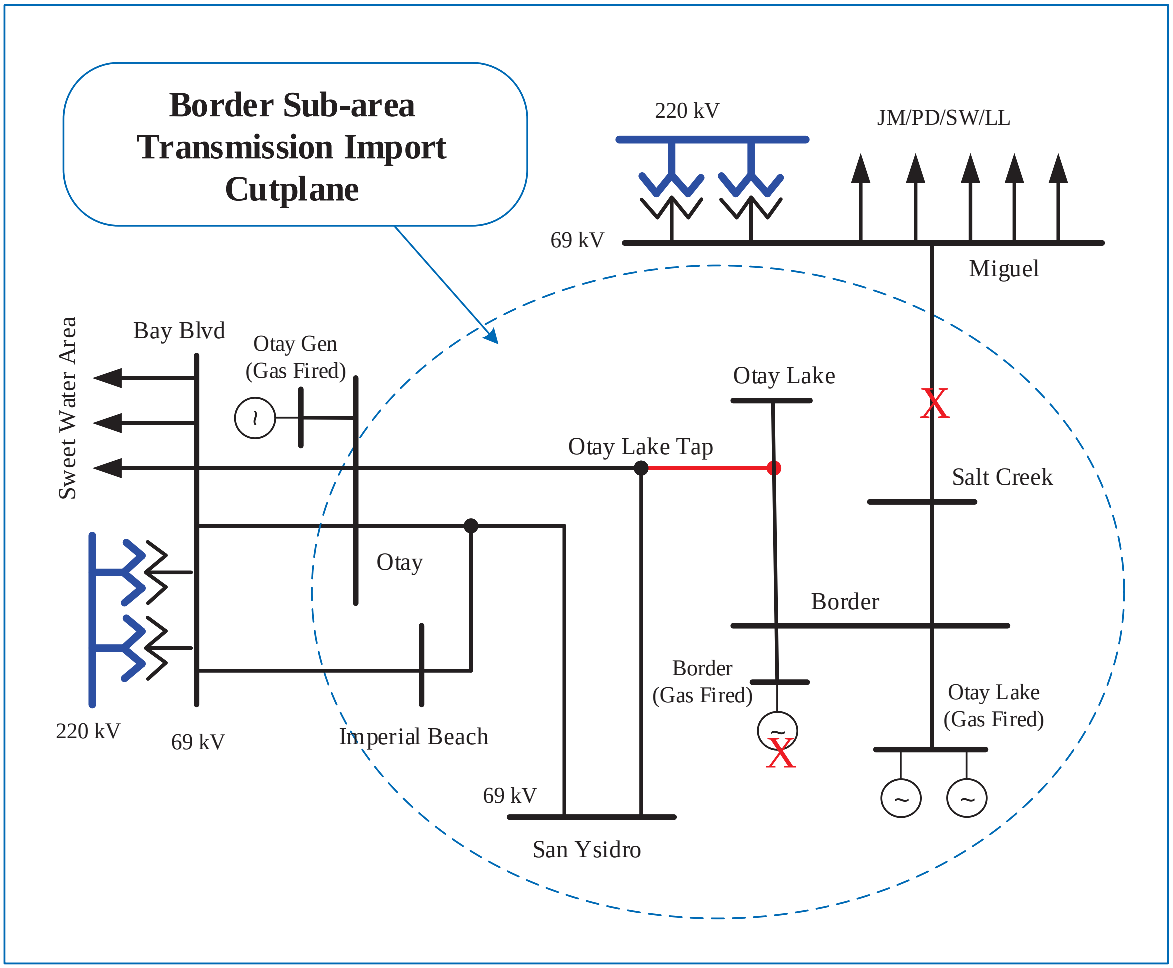
Pala Outer sub-area has been eliminated due to change in LCR criteria.

3.3.10.6 *Border Sub-area*

Border is Sub-area of the San Diego – Imperial Valley LCR Area.

Border LCR Sub-area Diagram

Figure 3.3-100 Border LCR Sub-area



Border LCR Sub-area Load and Resources

Table 3.3-87 provides the forecast load and resources in Border LCR Sub-area in 2021. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-87 Border Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	162	Market, Net Seller, Battery	143	143
AAEE	-8	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	154	LTPP Preferred Resources	0	0
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	156	Total	143	143

Border LCR Sub-area Hourly Profiles

Figure 3.3-101 illustrates the 2021 annual load forecast profile in the Border LCR sub-area and the Category P1 transmission capability without gas generation. Figure 3.3-102 illustrates the 2021 daily load forecast profile for the peak day in the sub-area along with the load serving capabilities. The illustration also includes an estimate of 160/800 MW/MWh energy storage that could be added in this local area from charging restriction perspective. In addition, it is estimated that 46/230 MW/MWh energy storage are required to displace the LCR requirement for gas generation, assuming the biggest energy storage unit is 23/115 MW/MWh.

Figure 3.3-101 Borden LCR Sub-area 2021 Annual Day Forecast Profiles

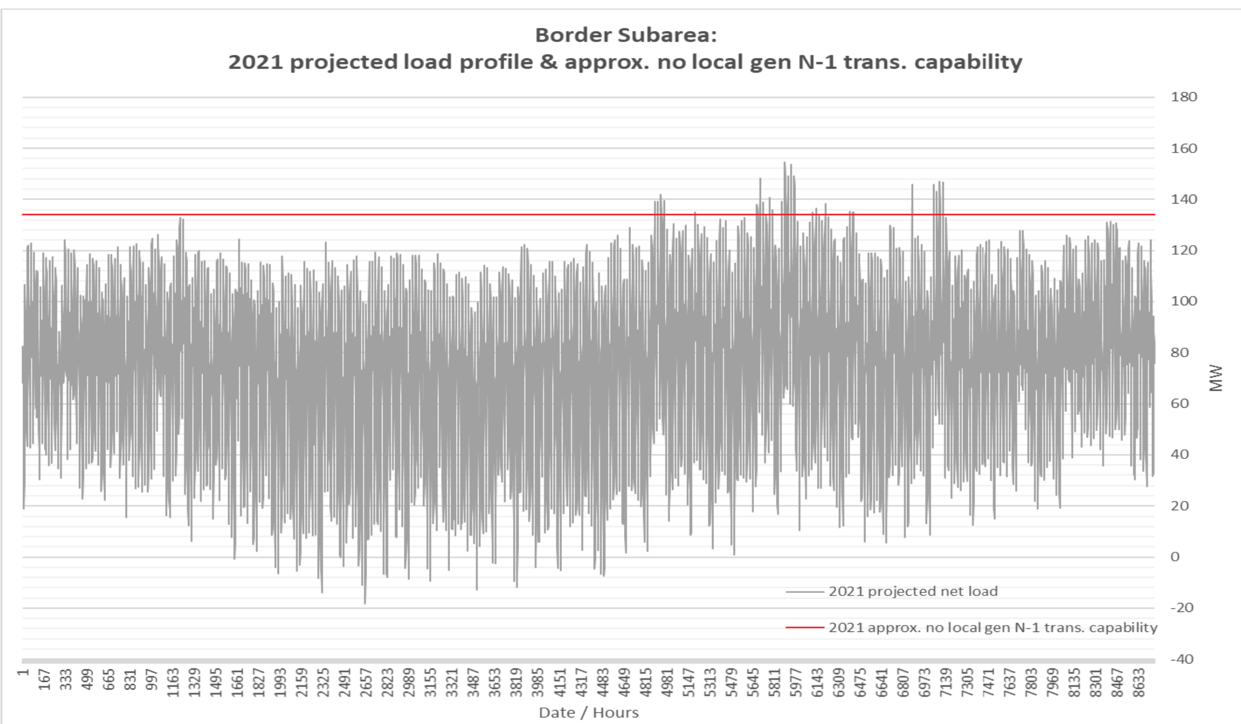
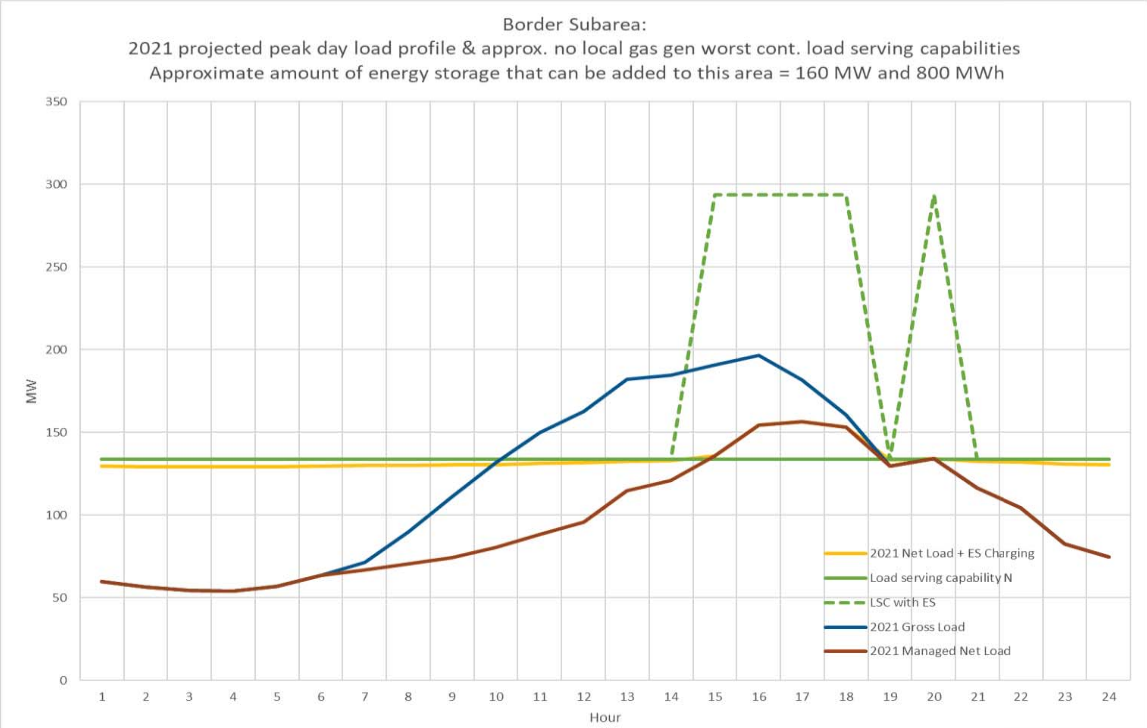


Figure 3.3-102 Border LCR Sub-area 2021 Peak Day Forecast Profiles



Border LCR Sub-area Requirement

Table 3.3-88 identifies the sub-area requirements. The LCR requirement for Category P3 contingency is 60 MW.

Table 3.3-88 Border LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	B	Otay – Otay Lake Tap 69 kV	Border unit out of service followed by the outage of Miguel-Salt Creek 69 kV #1	60

Effectiveness factors:

All units within the Border Sub-area have the same effectiveness factor.

3.3.10.7 ***San Diego Sub-area***

San Diego is Sub-area of the San Diego-Imperial Valley LCR Area.

San Diego LCR Sub-area Diagram

Please refer to Figure 3.3-96 above.

San Diego LCR Sub-area Load and Resources

Table 3.3-89 provides the forecast load and resources in San Diego LCR sub-area in 2021. The list of generators within the LCR sub-area are provided in Attachment A.

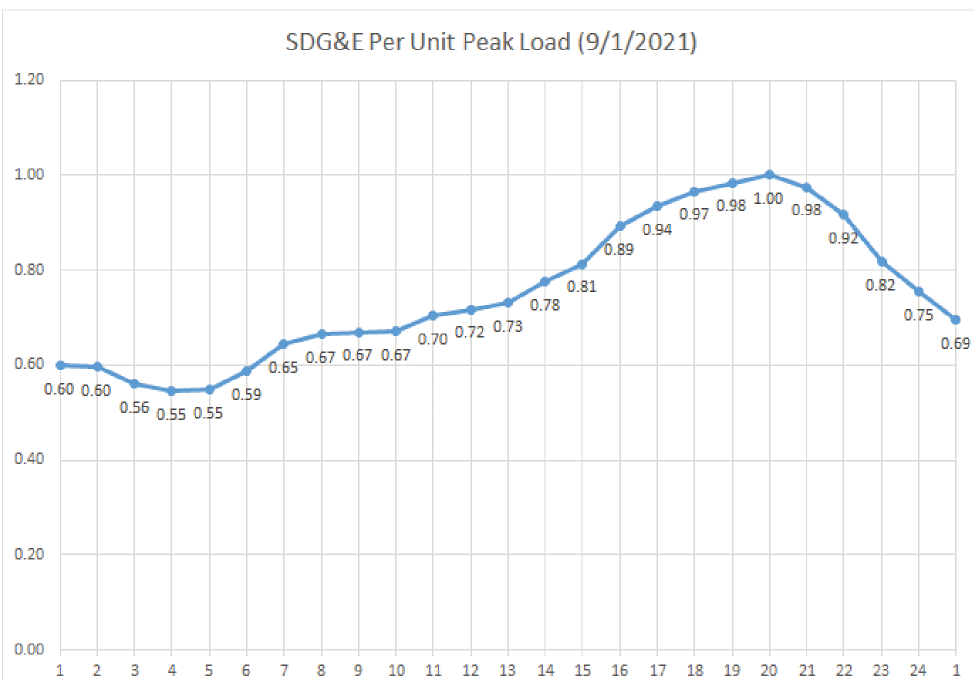
Table 3.3-89 San Diego Sub-area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4443	Market, Net Seller, Battery, Wind	2958	2958
AAEE	-28	Solar	15	0
Behind the meter DG	0	QF	2	2
Net Load	4415	LTPP Preferred Resources	0	0
Transmission Losses	108	Existing Demand Response	7	7
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	4523	Total	2982	2967

San Diego LCR Sub-area Hourly Profiles

Figure 3.3-103 illustrates the forecast 2021 profile for the summer peak day for the San Diego LCR sub-area. Due to the interaction between the overall LA Basin and the San Diego-Imperial Valley areas, the load profile with load serving capability, and the energy storage addition based on its charging capability are evaluated and included for the San Diego-Imperial Valley area.

Figure 3.3-103 San Diego LCR Sub-area 2021 Peak Day Forecast Profiles



San Diego LCR Sub-area Requirement

Table 3.3-90 identifies the sub-area LCR requirements. The Category P6 contingency LCR requirement is 2270 MW.

Table 3.3-90 San Diego Sub-area LCR Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P6	Remaining Sycamore-Suncrest 230 kV	ECO-Miguel 500 kV line, system readjustment, followed by one of the Sycamore-Suncrest 230 kV	2270

Effectiveness factors:

See Attachment B - Table titled San Diego.

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

3.3.10.8 *San Diego-Imperial Valley Overall*

San Diego-Imperial Valley LCR area Hourly Profiles

Since the San Diego sub-area has all the substation loads, the overall San Diego-Imperial Valley area has the same load profile as the San Diego bulk sub-area. The Imperial Valley area has generating resources.

Figure 3.3-104 illustrates the forecast 2021 profile for the summer peak day in the San Diego-Imperial Valley LCR area with the Category P1 normal and emergengy load serving capabilities without local gas resources.

Figure 3.3-105 and Figure 3.3-106 illustrate that load serving capability is higher by retaining some local gas generation that was procured as part of long term procurement plan for San Diego local area, some amount of energy storage for the overall area can be accommodated and it is limited by the charging capability under the extended transmission contingency condition Table 3.3-91 provides a summary of the estimated amount of energy storage that can be accommodated from the charging limitation perspective for the subareas and the overall LCR area.

Figure 3.3-104 San Diego-Imperial Valley area 2021 Peak Day Forecast Profiles and Load Serving Capability Without Local Gas Generation

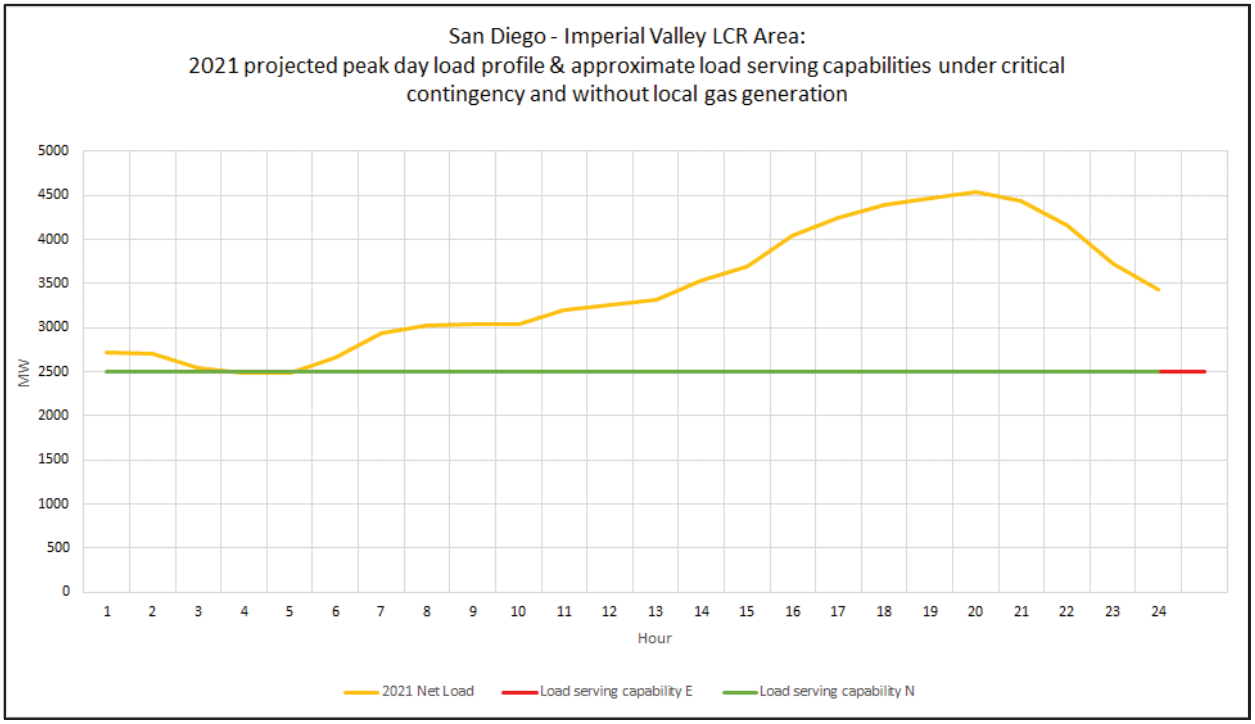


Figure 3.3-105 San Diego-Imperial Valley Area 2021 Peak Day Forecast Profiles with Higher Load Serving Capability

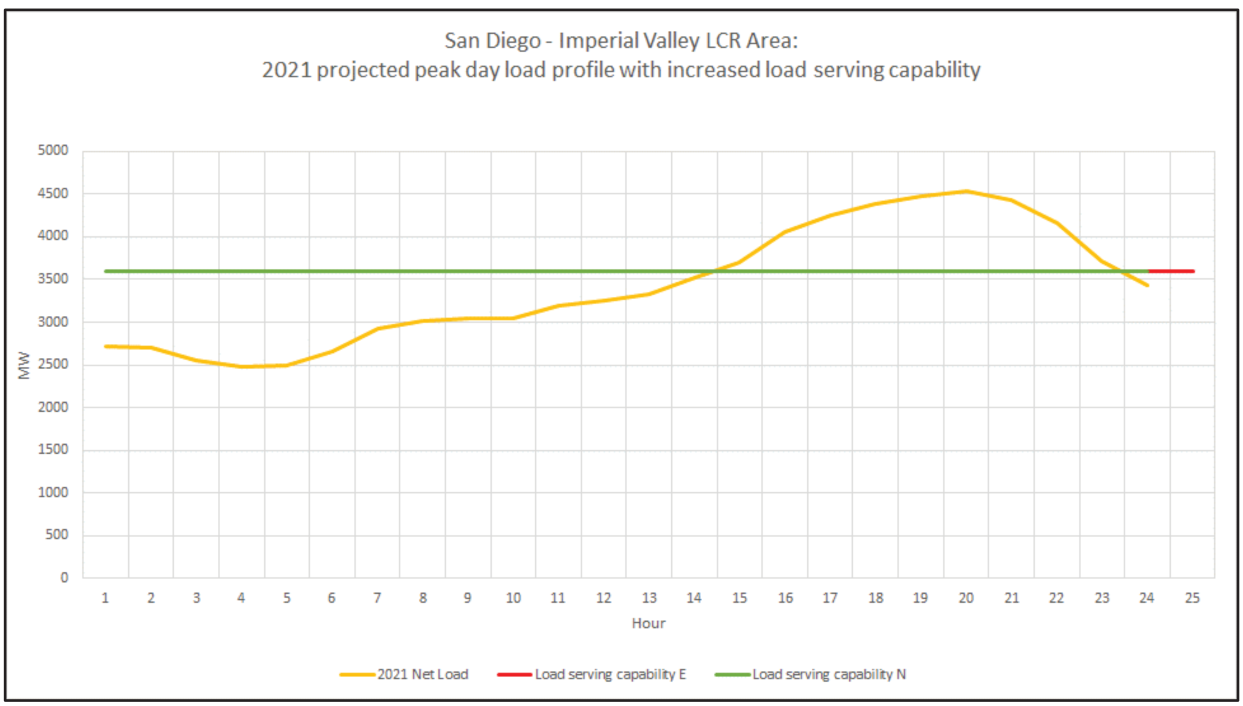
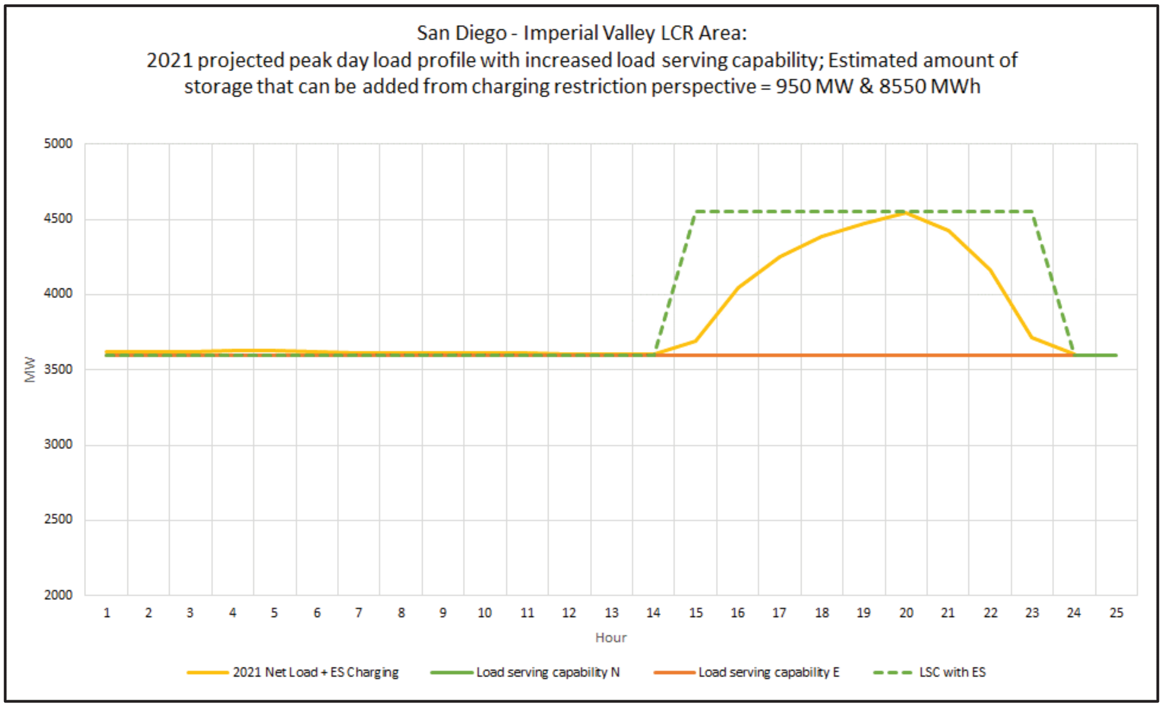


Figure 3.3-106 San Diego-Imperial Valley Area 2021 Estimated Amount of Storage that Can Be Added With Higher Load Serving Capability



The following is a summary of estimated amount of storage for the sub-areas and the overall area based on maximum charging capability perspective. Due to non-linearity of power system and the various critical contingencies and load shapes for each sub-area and the overall area, it is noted that the estimated maximum amount of storage for the sub-areas many not add up to be sum of the overall area. Since the San Diego sub-area has all the substation loads, the overall San Diego-Imperial Valley area has the same load profile as the San Diego bulk sub-area and therefore same amount of energy storage for the San Diego sub-area. The Imperial Valley area (of the overall San Deigo-Imperial Valley) has generating resources only. The estimated maximum amount of storage for the LCR area is the amount listed in the last row in the table.

Table 3.3-91 Estimated San Diego Sub-areas and Overall Area Energy Storage Capacity and Energy Based on Maximum Charging Capability Perspective

Area/Sub-area	Estimated Energy Storage Maximum Capacity (MW)	Estimated Energy Storage Maximum Energy (MWh)
El Cajon sub-area	48	432
Border sub-area	160	800
San Diego sub-area	950	8550
Overall San Diego-Imperial Valley Area	950	8550

San Diego-Imperial Valley LCR area Requirement

Table 3.3-92 identifies the area LCR requirements. The LCR requirement for Category P6 contingency is 3888 MW.

Table 3.3-92 San Diego-Imperial Valley LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2021	First Limit	P3	Imperial Valley – El Centro 230 kV Line (S-Line)	TDM generation, system readjustment, followed by Imperial Valley-North Gila 500 kV line	3888

Further explanation regarding coordination between LA Basin and San Diego-Imperial Valley can be found in section 3.3.9.8.2 above.

Effectiveness factors:

See Attachment B - Table titled San Diego.

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

Changes compared to 2020 LCT Study

Compared with the 2020 LCT Study results, the demand forecast is lower by 90 MW. The overall LCR needs for the San Diego-Imperial Valley decreases by 7 MW due to lower demand forecast. The reason that the LCR reduction is not commensurate with the decrease in the demand forecast is because of the significant reduction in the LCR requirement in the western LA Basin due to implementation of the 230kV portion of the Mesa Loop-In Project. Lower generation dispatch in the western LA Basin also affects the LCR requirement for the overall San Diego-Imperial Valley the generating units in the wester LA Basin are also effective, albeit small, in helping to mitigate the identified loading concern in the overall San Diego-Imperial Valley area.

3.3.11 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

- o No issues were observed for category B outage followed by a common-mode N-2 outage
- o All the N-1-1 issues that were observed can either be mitigated by the existing UVLS or by an operating procedure

3.4 Summary of Engineering Estimates for Intermediate Years by Local Area

Engineering estimates, along with detailed explanations for contributing factors in each local area are given below per methodology explained in Chapter 2 above. The estimates represent an engineering approximation. They are not actual technical studies and they may be superseded by actual technical studies.

3.4.19.1 *Humboldt Area*

The net peak load growth from 2021 to 2025 is estimated at 0 MW/year.

There is no new transmission project that directly affects the LCR change from 2021 to 2025.

There is no new resource that directly affects the LCR change from 2021 to 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There is no resource projected to retire that directly affects the LCR change from 2021 to 2025.

The total increase for each intermediate year depends strictly on the study results between years 2021 and 2025 and it is estimated at about 0.5 MW/year for Category P6.

Table 3.4-1 ISO's estimated Humboldt LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First Limit	P6	Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115 kV & Humboldt - Humboldt Bay 115 kV	131
2023	First Limit	P6	Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115 kV & Humboldt - Humboldt Bay 115 kV	131

3.4.19.2 *North Coast/ North Bay Area*

The net peak load growth from 2021 to 2025 is estimated at about 6 MW/year.

There is no new transmission project that directly affects the LCR change from 2021 to 2025.

There is no new resource that directly affects the LCR change from 2021 to 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There is no resource projected to retire that directly affects the LCR change from 2021 to 2025.

The total increase for each intermediate year depends on load growth and the study results for year 2021 only and it is estimated at about -1.5 MW/year for Category P6

Table 3.4-2 ISO's estimated North Coast/ North Bay LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First Limit	P2-4	Tulucay - Vaca Dixon 230 kV Line	Lakeville 230 kV – Section 2E & 1E	842
2023	First Limit	P2-4	Tulucay - Vaca Dixon 230 kV Line	Lakeville 230 kV – Section 2E & 1E	840

3.4.19.3 *Sierra Area*

The net peak load growth from 2021 to 2025 is estimated at 13 MW/year.

There are 5 new transmission projects that directly affects the LCR change from 2021 to 2025.

- Rio Oso 230/115 kV transformer upgrade (July 2022)
- South of Palermo 115 kV Reinforcement (Nov 2022)
- Rio Oso Area 230 kV Voltage Support (Sept 2022)
- East Marysville 115/60 kV (Dec 2022)
- Gold Hill 230/115 kV Transformer Addition (Dec 2024)

No project impacts the 2022 LCR needs and four projects impact 2023 LCR needs. The 2023 impact is significant since these projects address the overall requirement, except for a 30 MW higher requirement in the Gold Hill-Drum sub-area.

There is no new resource that directly affects the LCR change from 2021 to 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There is no resource projected to retire that directly affects the LCR change from 2021 to 2025.

The total requirement for year 2022 depends on the result for year 2021 only plus an estimated increase of 13 MW/year for Category P6. The total requirement for year 2023 depends on th results for year 2025 only plus an 30 MW increase for Gold Hill-Drum sub-area anda decrease of 26 MW due to load growth for Category P6.

Table 3.4-3 ISO's estimated Sierra LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First limit	P6	Table Mountain – Pease 60 kV	Table Mountain – Palermo 230 kV Table Mountain – Rio Oso 230 kV	1834
2023	First limit	P6	Table Mountain – Pease 60 kV	Table Mountain – Palermo 230 kV Table Mountain – Rio Oso 230 kV	1371

3.4.19.4 *Stockton Area*

The net peak load growth from 2021 to 2025 is estimated at 9 MW/year (1 MW/year in Lockeford and 8 MW/year in Tesla-Bellota).

There are two new transmission project that directly affects the LCR change from 2021 to 2025.

- Vierra 115 kV Looping Project (Jan 2023)
- Lockeford-Lodi Area 230 kV Development (Jun 2025)

The Vierra 115 kV Looping Project has a influence on the 2023 results only. The second project has no impact on the 2022 and 2023 results.

There is one new resource that directly affects the LCR change from 2021 to 2025. This is an existing system resource that will be included in the local area as a result of the Vierra 115 kV Looping Project and only after January 2023.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There is no resource projected to retire that directly affects the LCR change from 2021 to 2025.

The total increase for each intermediate year depends only on the available resources and the transmission comfiguration, since both sub-areas are deficient in both years.

Table 3.4-4 ISO's estimated Stockton LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First Limit	N/A	Stockton Overall		596
2023	First Limit	N/A	Stockton Overall		642

3.4.19.5 *Bay Area*

The net peak load growth from 2021 to 2025 is estimated at -9 MW/year.

There are 5 new transmission projects that directly affect the LCR change from 2021 to 2025.

- Oakland Clean Energy Initiative Project (Aug. 2022)
- Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade (Apr. 2022)
- East Shore-Oakland J 115 kV Reconductoring Project (June 2022)

The first project impacts year 2023 only, the rest impact both years. . For both years the TPP project impact is minimal to the Bay Area overall requirement.

There are 6 new resources that directly affect the LCR change from 2021 to 2025. About 111 MW of preferred resources (Battery), will be available in year 2023 only. These new resources do not change the LCR needs in the Bay Area overall in any significant way.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There are two resources projected to retire that directly affects the LCR change from 2021 to 2025. The retirement of the last two Oakland resources in 2023 only does not change the LCR needs in the Bay Area overall in any significant way.

The total decrease for each intermediate year depends on the load decrease and the study results between years 2021 and 2025 and it is estimated at about -61 MW/year for Category P6.

Table 3.4-5 ISO's estimated Bay Area LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First limit	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	6292
2023	First limit	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	6231

3.4.19.6 *Fresno Area*

The net peak load growth from 2021 to 2025 is estimated at 14.5 MW/year.

There are 4 new transmission projects that directly affect the LCR change from 2021 to 2025.

- Reedley 70 kV Reinforcement Projects (Dec 2021)
- Herndon-Bullard Reconductoring Projects (Jan 2021)
- Wilson 115 kV Area Reinforcement (May 2023)
- Bellota-Warnerville 230 kV Line Reconductoring (Dec 2023)

The first two project impact the 2022 and 2023 LCR needs, then 3rd projects the 2023 LCR need only. The TPP project impact is minimal to both years because none of the projects directly impact the Fresno overall LCR need.

There are no new resources that directly affect the LCR change from 2021 to 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There is no resource projected to retire that directly affects the LCR change from 2021 to 2025.

The total increase for each intermediate year depends on load growth and the study results between years 2021 and 2025 and it is estimated at about 69 MW/year for Category P6.

Table 3.4-6 ISO's estimated Fresno LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First limit	P6	GWF-Contandida 115 kV Line	Panoche-Helm 230 kV Line and Gates-McCall 230 kV line	1763
2023	First limit	P6	GWF-Contandida 115 kV Line	Panoche-Helm 230 kV Line and Gates-McCall 230 kV line	1832

3.4.19.7 ***Kern Area***

The net peak load growth from 2021 to 2025 is not estimated to have any impacts to the overallLCR needs.

There are 5 new transmission projects that directly affect the LCR change from 2021 to 2025.

- Bakersfield Nos. 1 and 2 230 kV Tap Lines Reconductoring (Dec 2024)
- Midway-Kern PP 230 kV #2 Line (Phase 1 - Mar 2021, Phase 2 - Mar 2023)
- Midway-Kern PP 1, 3 & 4 230 kV Line Capacity Increase (Phase 1 - Mar 2021, Phase 2 - Apr 2024)
- Kern PP 115 kV Area Reinforcement (Dec 2023)
- Wheeler Ridge Junction Station (May 2024)

Only the second project impacts the 2023 LCR needs. The TPP project impact is significant to year 2023 only because the project does directly impact the South Kern PP sub-area need.

There are no new resources that directly affect the LCR change from 2021 to 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There is no resource projected to retire that directly affects the LCR change from 2021 to 2025.

The total requirement depends on the resources available and the system configuration only for 2022 since all sub-areas are deficient. Year 2023 LCR results are influenced by the transmission project in an unknown manner since the sytem was not studied with just one upgrade in-service therefore based on engineering judjement CAISO expects half the decrease in requirements to be attributed to this project or 113 MW.

Table 3.4-7 ISO's estimated Kern LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	N/A	P6	Aggregate of Sub-areas.		413
2023	N/A	P6	Aggregate of Sub-areas.		300

3.4.19.8 *Big Creek/Ventura Area*

The net peak load growth from 2021 to 2025 is estimated at -5.5 MW/year.

There are one new transmission project that directly affect the LCR change from 2021 to 2025.

The Sylmar-Pardee 230 kV Rating Increase Project influences the 2023 LCR needs only as a step down decrease of LCR needs.

There are no new resources that directly affect the LCR change from 2021 to 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There are 3 resources projected to retire that directly affects the LCR change from 2021 to 2025. Projected retirement of Elwood will not influence the overall Big Creek/Ventura LCR capacity needs since the resource will only be allowed to retire after suitable replacement is in place at or near the same bus (Goleta). The retirement of Ormond Beach units 1 and 2 will result in Pastoria (CCGT) becoming the biggest single resource contingency therefore resulting in a decrease for Category B LCR need and at the same time it will result in an increase in Category C LCR needs because Ormond Beach was one of the most effective resources for overloads on the remaining Sylmar-Pardee 230 kV line and therefore its absence will be replaced by less effective resources, however this change is estimated to occur past year 2023.

The total LCR requirement for year 2022 is only dependent on year 2021 and load growth between years. The majority of the decrease for year 2023 is attributed to a step function reduction due to the Sylmar-Pardee 230 kV Rating Increase Project with little dependence on load growth.

Table 3.4-8 ISO's estimated Big Creek/Ventura LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)

2022	First Limit	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	2291
2023	First Limit	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	1013

3.4.19.9 *LA Basin Area*

The net peak load growth from 2021 to 2025 is estimated at -26 MW/year.

There are 3 new transmission projects that directly affect the LCR change from 2021 to 2025.

- Mesa Loop-In Project and Laguna Bell Corridor 230 kV Line Upgrades (3/1/2022)
- Delaney – Colorado River 500 kV Line (12/31/2021)
- West of Devers 230 kV Line Upgrades (12/31/2021)

All TPP projects influence year 2022 and 2023 LCR needs. The TPP projects impact is significant to the LA Basin overall LCR need and acts as a step function increase the LCR needs in 2022.

There are no new resources that directly affect the LCR change from 2021 to 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There are 7 resources projected to retire that directly affect the LCR change from 2021 to 2025. These resources are all projected to retire after 2023 due to OTC compliance dates, therefore they do not influence the needs in 2022 and 2023.

There will be a step function increase in 2022 due to new transmission projects as well as reduction in San Diego-Imperial Valley area needs due to the “S” line upgrade and installation of new more effective resources in San Diego-Imperial Valley, coupled with LA Basin and San Diego load growth.

Table 3.4-9 ISO’s estimated LA Basin LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First Limit	N/A	Sum of Western and Eastern	See Western and Eastern	6387
2022	Second Limit	P3	El Centro 230/92 kV	TDM, system readjustment and Imperial Valley–North Gila 500 kV line	6081
2023	First Limit	N/A	Sum of Western and Eastern	See Western and Eastern	6361

2023	Second Limit	P3	El Centro 230/92 kV	TDM, system readjustment and Imperial Valley–North Gila 500 kV line	6333

3.4.19.10 *San Diego-Imperial Valley Area*

The net peak load growth from 2021 to 2025 is estimated at 38 MW/year.

There are 5 new transmission projects that directly affect the LCR change from 2021 to 2025.

- Artesian 230 kV Expansion with 69 kV Upgrade (Q2 2022)
- South Orange County Reliability Enhancement (Q2 2021)
- 2nd San Marcos–Escondido 69 kV Line (Q1 2022)
- Imperial Valley-El Centro 230 kV (“S”) Line Upgrade (Dec 2021)
- Reconductor of Stuart Tap–Las Pulgas 69 kV Line (TL690E) (Q1 2025)

The first four projects impact the 2022 and 2023 LCR needs, the 5th project does not impact anyone of these years. In 2022 there will be a step function decrease in LCR needs due to the “S” line upgrade.

There are 10 new resources that directly affect the LCR change from 2021 to 2025. About 100 MW NQC or 86 MW at peak of new resources are available for both 2022 and 2023. An additional 358 MW NQC or 350 MW at peak of new resources are available in 2023 only. The majority of the new resources available at the time of the peak do change the LCR needs in the San Diego-Imperial Valley area since they are highly effective in mitigating the local need.

There is no projected change in resource contractual status that directly affects the LCR change from 2021 to 2025.

There is no resource projected to retire that directly affects the LCR change from 2021 to 2025.

There will be a step function decrease in 2022 due to new highly effective resources and and new transmission project and there will be step function decrease in 2023 due to additional highly effective new resources coupled with LA Basin and San Diego load growth for Category P3.

Table 3.4-10 ISO’s estimated San Diego-Imperial Valley LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2022	First Limit	P3	El Centro 230/92 kV	TDM power plant, system readjustment and Imperial Valley–North Gila 500 kV line	3640
2023	First Limit	P3	El Centro 230/92 kV	TDM power plant, system readjustment and Imperial Valley–North Gila 500 kV line	3481

Attachment A – List of physical resources by PTO, local area and market ID

PTO	MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR AREA NAME	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
PG&E	ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.40	1	Bay Area	Oakland		MUNI
PG&E	ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	23.50	1	Bay Area	Oakland		MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	1	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	2	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	3	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	4	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	5	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	6	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	7	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	8	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	9	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	10	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	11	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	34.02	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	16.42	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	7.73	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO1	32176	SHILOH	34.5	31.50	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	31.50	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	21.53	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	21.00	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.56	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	190.00	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG2	33188	MARSHCT2	16.4	189.21	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG3	33189	MARSHCT3	16.4	188.50	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG4	33189	MARSHCT4	16.4	189.89	4	Bay Area	Contra Costa	Aug NQC	Market

PG&E	COCOSB_6_SOLAR				0.00		Bay Area	Contra Costa	Not modeled Energy Only	Solar
PG&E	CROKET_7_UNIT	32900	CRCKTCOG	18	211.49	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	5.13	1	Bay Area	Pittsburg	Aug NQC	Solar
PG&E	DELTA_2_PL1X4	33107	DEC STG1	24	269.60	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	DIXNLD_1_LNDFL				0.64		Bay Area		Not modeled Aug NQC	Market
PG&E	DUANE_1_PL1X3	36863	DVRaGT1	13.8	48.27	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36864	DVRbGT2	13.8	48.27	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36865	DVRaST3	13.8	46.96	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	GATWAY_2_PL1X3	33118	GATEWAY1	18	180.78	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33119	GATEWAY2	18	171.17	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33120	GATEWAY3	18	171.17	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	69.00	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	36.00	2	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35851	GROYPKR1	13.8	47.60	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35852	GROYPKR2	13.8	47.60	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market

PG&E	GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.20	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GRZZLY_1_BERKLY	32741	HILLSIDE_12	12.5	14.67	1	Bay Area		Aug NQC	Net Seller
PG&E	KELSO_2_UNITS	33813	MARIPCT1	13.8	48.09	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33815	MARIPCT2	13.8	48.09	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33817	MARIPCT3	13.8	48.09	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33819	MARIPCT4	13.8	48.09	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				0.17		Bay Area		Not modeled Aug NQC	Market
PG&E	LECEF_1_UNITS	35858	LECEFST1	13.8	111.58	1	Bay Area	San Jose, South Bay-Moss Landing		Market
PG&E	LECEF_1_UNITS	35854	LECEFGT1	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35855	LECEFGT2	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35856	LECEFGT3	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35857	LECEFGT4	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.50	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	47.60	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.40	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33113	LMECST1	18	243.71	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33111	LMECCT2	18	165.41	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33112	LMECCT1	18	165.41	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	MARTIN_1_SUNSET				1.22		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	METEC_2_PL1X3	35883	MEC STG1	18	213.13	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	MISSIX_1_QF				0.01		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	MLPTAS_7_QFUNTS				0.00		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	36223	DUKMOSS3	18	183.60	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36221	DUKMOSS1	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36222	DUKMOSS2	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36226	DUKMOSS6	18	183.60	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36224	DUKMOSS4	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36225	DUKMOSS5	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	NEWARK_1_QF				0.05		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	OAK C_1_EBMUD				1.20		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	Retired by 2025	Market
PG&E	OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Bay Area	Oakland	Retired by 2025	Market
PG&E	OAK C_7_UNIT 3	32903	OAKLND 3	13.8	0.00	1	Bay Area	Oakland	Retired by 2021	Market
PG&E	OAK L_1_GTG1				0.00		Bay Area	Oakland	Not modeled Energy Only	Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	1	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	2	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	3	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	4	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	5	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	6	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	7	Bay Area	Ames		Market
PG&E	PALALT_7_COBUG				4.50		Bay Area		Not modeled	MUNI
PG&E	RICHMN_1_CHVSR2				2.30		Bay Area		Not modeled Aug NQC	Solar
PG&E	RICHMN_1_SOLAR				0.54		Bay Area		Not modeled Aug NQC	Solar
PG&E	RICHMN_7_BAYENV				2.00		Bay Area		Not modeled Aug NQC	Market

PG&E	RUSCTY_2_UNITS	35306	RUSELST1	15	237.09	3	Bay Area	Ames	No NQC - Pmax	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	RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	47.60	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	SHELRF_1_UNITS	33142	SHELL 2	12.5	10.91	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SHELRF_1_UNITS	33143	SHELL 3	12.5	10.91	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SHELRF_1_UNITS	33141	SHELL 1	12.5	5.88	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SRINTL_6_UNIT	33468	SRI INTL	9.11	0.78	1	Bay Area		Aug NQC	QF/Selfgen
PG&E	STAUFF_1_UNIT	33139	STAUFER	9.11	0.01	1	Bay Area		Aug NQC	QF/Selfgen
PG&E	STOILS_1_UNITS	32921	CHEVGEN1	13.8	2.09	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32922	CHEVGEN2	13.8	2.09	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32923	CHEVGEN3	13.8	0.97	3	Bay Area	Pittsburg	Aug NQC	Market
PG&E	SWIFT_1_NAS	35623	SWIFT	21	3.00	BT	Bay Area	San Jose, South Bay-Moss Landing		Battery
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.05	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.05	2	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	3.08	3	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	UNCHEM_1_UNIT	32920	UNION CH	9.11	13.10	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.02	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.02	2	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.02	3	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	USWNDR_2_LABWD1				1.89		Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD	365574	SOLANO2W		18.24	2	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD	365566	SOLANO1W		3.22	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD2	365600	SOLANO3W		26.84	3	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWPJR_2_UNITS	39233	GRNRDG	0.69	16.42	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	7.98	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZOND_6_UNIT	35316	ZOND SYS	9.11	3.59	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_MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	Bay Area	San Jose, South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_NA	35861	SJ-SCL W	4.3	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen

PG&E	ZZ_NA	36209	SLD ENRG	12.5	0.00	1	Bay Area	South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_SEAWST_6_LAPOS	35312	FOREBAYW	22	0.00	1	Bay Area	Contra Costa	No NQC - est. data	Wind
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	1.90	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	0.00	2	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_ZANKER_1_UNIT 1	35861	SJ-SCL W	4.3	0.00	RN	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	30045	MOSSLAND	500	300.00	ES	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	30755	MOSSLNSW	230	182.50	ES	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	35646	MRGN HIL	115	75.00	ES	Bay Area	San Jose, South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	30522	0354-WD	21	1.83	EW	Bay Area	Contra Costa	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	365540	Q1016		0.00	1	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	32741	HILLSIDE		0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	365559	STANFORD		0.00	RN	Bay Area		Energy Only	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	ZZZ_New Unit	35307	A100US-L	12.6	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZZZ_METCLF_1_QF				0.00		Bay Area		Retired	QF/Selfgen
PG&E	ZZZZZ_USWNDR_2_UNITS	32168	EXNCO	9.11	0.00	1	Bay Area	Contra Costa	Retired	Wind
PG&E	ZZZZZZ_COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_CONTAN_1_UNIT	36856	CCA100	13.8	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	Retired	MUNI
PG&E	ZZZZZZ_FLOWD1_6_ALTPP 1	35318	FLOWDPTR	9.11	0.00	1	Bay Area	Contra Costa	Retired	Wind
PG&E	ZZZZZZ_LFC 51_2_UNIT 1	35310	PPASSWND	21	0.00	1	Bay Area		Retired	Wind
PG&E	ZZZZZZ_MOSSLD_7_UNIT 6	36405	MOSSLND6	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market
PG&E	ZZZZZZ_MOSSLD_7_UNIT 7	36406	MOSSLND7	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market

PG&E	ZZZZZZ_PITTSP_7_UNIT 5	33105	PTSB 5	18	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	Bay Area		Retired	QF/Selfgen
PG&E	ADERA_1_SOLAR1	34319	CHWCHLAS	0.48	0.00	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Energy Only	Solar
PG&E	ADMEST_6_SOLAR	34315	ADAMS_E	12.5	0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	AGRICO_6_PL3N5	34608	AGRICO	13.8	22.69	3	Fresno	Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	43.13	4	Fresno	Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	7.47	2	Fresno	Herndon		Market
PG&E	AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	AVENAL_6_AVSLR1	34691	AVENAL_1	21	0.00	EW	Fresno	Coalinga	Energy Only	Solar
PG&E	AVENAL_6_AVSLR2	34691	AVENAL_1	21	0.00	EW	Fresno	Coalinga	Energy Only	Solar
PG&E	AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	BALCHS_7_UNIT 1	34624	BALCH	13.2	31.00	1	Fresno	Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Fresno	Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 3	34614	BLCH	13.8	54.60	1	Fresno	Herndon	Aug NQC	Market
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	2.70	1	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	2.70	2	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	2.09	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	QF/Selfgen
PG&E	CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.85	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	QF/Selfgen
PG&E	CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	9.30	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV		Market
PG&E	CORCAN_1_SOLAR1	34690	CORCORAN	12.5	5.40	FW	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	CORCAN_1_SOLAR2	34692	CORCORAN	12.5	2.97	FW	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	CRESSY_1_PARKER	34140	CRESSEY	115	1.29		Fresno		Not modeled Aug NQC	MUNI

PG&E	CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.00	1	Fresno	Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	0.01	1	Fresno	Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	0.00	1	Fresno	Borden	Aug NQC	Market
PG&E	CURTIS_1_CANLCK				0.00		Fresno		Not modeled Aug NQC	Market
PG&E	CURTIS_1_FARFLD				0.47		Fresno		Not modeled Aug NQC	Market
PG&E	DAIRLD_1_MD1SL1				0.00		Fresno		Energy Only	Solar
PG&E	DAIRLD_1_MD2BM1				0.00		Fresno		Energy Only	Market
PG&E	DINUBA_6_UNIT	34648	DINUBA E	13.8	0.00	1	Fresno	Herndon, Reedley	Mothballed	Market
PG&E	EEKTMN_6_SOLAR1	34629	KETTLEMN	0.8	0.00	1	Fresno		Energy Only	Solar
PG&E	ELCAP_1_SOLAR				0.00		Fresno		Not Modeled Aug NQC	Solar
PG&E	ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	9.59	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	90.72	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	MUNI
PG&E	EXCLSG_1_SOLAR	34623	Q678	0.5	16.20	1	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	FRESHW_1_SOLAR1	34699	Q529	0.39	0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	8.56	2	Fresno	Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	4.57	3	Fresno	Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.21	4	Fresno	Borden	Aug NQC	Net Seller
PG&E	GIFENS_6_BUGSL1	34644	Q679	0.55	5.40	1	Fresno		Aug NQC	Solar
PG&E	GIFFEN_6_SOLAR	34467	GIFFEN_DIST	12.5	2.70	1	Fresno	Herndon	Aug NQC	Solar
PG&E	GIFFEN_6_SOLAR1				0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	GUERNS_6_SOLAR	34463	GUERNSEY_D2	12.5	2.70	5	Fresno		Aug NQC	Solar
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY_D1	12.5	2.70	8	Fresno		Aug NQC	Solar
PG&E	GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	45.30	1	Fresno	Herndon, Hanford		Market
PG&E	GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	45.30	1	Fresno	Herndon, Hanford		Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	1	Fresno	Herndon	Aug NQC	Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	2	Fresno	Herndon	Aug NQC	Market
PG&E	HELMPG_7_UNIT 1	34600	HELMS	18	407.00	1	Fresno		Aug NQC	Market
PG&E	HELMPG_7_UNIT 2	34602	HELMS	18	407.00	2	Fresno		Aug NQC	Market
PG&E	HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Fresno		Aug NQC	Market
PG&E	HENRTA_6_SOLAR1				0.00		Fresno		Not modeled Aug NQC	Solar
PG&E	HENRTA_6_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	HENRTA_6_UNITA1	34539	GWF_GT1	13.8	44.99	1	Fresno			Market

PG&E	HENRTA_6_UNITA2	34541	GWF_GT2	13.8	44.89	1	Fresno			Market
PG&E	HENRTS_1_SOLAR	34617	Q581	0.38	27.00	1	Fresno	Herndon	Aug NQC	Solar
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	2.70	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	2.70	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	JAYNE_6_WLSLR	34639	WESTLNDS	0.48	0.00	1	Fresno	Coalinga	Energy Only	Solar
PG&E	KANSAS_6_SOLAR	34666	KANSASS_S	12.5	0.00	F	Fresno		Energy Only	Solar
PG&E	KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERMAN_6_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KERMAN_6_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KINGCO_1_KINGBR	34642	KINGSBUR	9.11	34.50	1	Fresno	Herndon, Hanford	Aug NQC	Net Seller
PG&E	KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Fresno	Herndon, Reedley	Aug NQC	Market
PG&E	KNGBRG_1_KBSLR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KNGBRG_1_KBSLR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Fresno		Energy Only	Solar
PG&E	LEPRFD_1_KANSAS	34680	KANSAS	12.5	5.40	1	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Fresno	Herndon		Market
PG&E	MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Fresno	Herndon		Market
PG&E	MCCALL_1_QF	34219	MCCALL 4	12.5	0.65	QF	Fresno	Herndon	Aug NQC	QF/Selfgen
PG&E	MCSWAN_6_UNITS	34320	MCSWAIN	9.11	9.60	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	MUNI
PG&E	MENBIO_6_RENEW1	34339	CALRENEW	12.5	1.35	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Aug NQC	Net Seller
PG&E	MERCED_1_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MERCED_1_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar

PG&E	MERCFL_6_UNIT	34322	MERCEDFL	9.11	3.36	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR1	34313	NORTHSTA	0.2	16.20	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Solar
PG&E	MNDOTA_1_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MSTANG_2_SOLAR	34683	Q643W	0.8	8.10	1	Fresno		Aug NQC	Solar
PG&E	MSTANG_2_SOLAR3	34683	Q643W	0.8	10.80	1	Fresno		Aug NQC	Solar
PG&E	MSTANG_2_SOLAR4	34683	Q643W	0.8	8.10	1	Fresno		Aug NQC	Solar
PG&E	ONLLPP_6_UNITS	34316	ONEILPMP	9.11	12.12	1	Fresno		Aug NQC	MUNI
PG&E	OROLOM_1_SOLAR1	34689	ORO LOMA_3	12.5	0.00	EW	Fresno	Panoche 115 kV	Energy Only	Solar
PG&E	OROLOM_1_SOLAR2	34689	ORO LOMA_3	12.5	0.00	EW	Fresno	Panoche 115 kV	Energy Only	Solar
PG&E	ORTGA_6_ME1SL1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	PAIGES_6_SOLAR	34653	Q526	0.55	0.00	1	Fresno	Coalinga, Panoche 115 kV	Energy Only	Solar
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	1	Fresno	Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	2	Fresno	Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	3	Fresno	Herndon	Aug NQC	MUNI
PG&E	PNCHPP_1_PL1X2	34328	STARGT1	13.8	54.18	1	Fresno	Panoche 115 kV		Market
PG&E	PNCHPP_1_PL1X2	34329	STARGT2	13.8	54.18	2	Fresno	Panoche 115 kV		Market
PG&E	PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Fresno	Herndon, Panoche 115 kV		Market
PG&E	PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	52.01	1	Fresno	Panoche 115 kV		Market
PG&E	REEDLY_6_SOLAR				0.00		Fresno	Herndon, Reedley	Not modeled Energy Only	Solar
PG&E	S_RITA_6_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	2.70	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	1.35	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_OS2BM2				0.00		Fresno	Coalinga	Energy Only	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	2.70	3	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	1.35	4	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	38.77	1	Fresno	Herndon	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	9.31	2	Fresno	Herndon	Aug NQC	Market

PG&E	STOREY_2_MDRCH2	34253	BORDEN D	12.5	0.28		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH3	34253	BORDEN D	12.5	0.19		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH4	34253	BORDEN D	12.5	0.20		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_7_MDRCHW	34209	STOREY D	12.5	0.82	1	Fresno		Aug NQC	Net Seller
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.70	1	Fresno	Herndon	Aug NQC	Solar
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.70	2	Fresno	Herndon	Aug NQC	Solar
PG&E	STROUD_6_WWHSR1				0.00		Fresno	Herndon	Energy Only	Solar
PG&E	SUMWHT_6_SWSSR1				5.00		Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_AMASR1	365514	Q1032G1	0.55	5.40	1	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_AZUSR1	365517	Q1032G2	0.55	5.40	2	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_ROJSR1	365520	Q1032G3	0.55	8.10	3	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_VERSR1	365520	Q1032G3	0.55	0.00	3	Fresno		Aug NQC	Solar
PG&E	TRNQLT_2_SOLAR	34340	Q643X	0.8	54.00	1	Fresno		Aug NQC	Solar
PG&E	ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	24.07	1	Fresno	Herndon	Aug NQC	Market
PG&E	VEGA_6_SOLAR1	34314	VEGA	34.5	0.00	1	Fresno		Energy Only	Solar
PG&E	WAUKNA_1_SOLAR	34696	CORCORANPV_S	21	5.40	1	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	WAUKNA_1_SOLAR2	34677	Q558	21	5.33	1	Fresno	Herndon, Hanford	No NQC - Pmax	Solar
PG&E	WFRESN_1_SOLAR				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	WHITNY_6_SOLAR	34673	Q532	0.55	0.00	1	Fresno	Coalinga, Panoche 115 kV	Energy Only	Solar
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	0.36	SJ	Fresno	Borden	Aug NQC	Market
PG&E	WOODWR_1_HYDRO				0.00		Fresno		Not modeled Energy Only	Market
PG&E	WRGHTP_7_AMENGY	34207	WRIGHT D	12.5	0.53	QF	Fresno		Aug NQC	QF/Selfgen
PG&E	ZZ_BORDEN_2_QF	34253	BORDEN D	12.5	1.30	QF	Fresno		No NQC - hist. data	Net Seller
PG&E	ZZ_BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.06	1	Fresno	Herndon	Aug NQC	QF/Selfgen
PG&E	ZZ_JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	0.00	1	Fresno			QF/Selfgen

PG&E	ZZ_KERKH1_7_UNIT 2	34343	KERCK1-2	6.6	8.50	2	Fresno	Herndon, Wilson 115 kV	No NQC - hist. data	Market
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.10	2	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	1	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	3	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_New Unit	34651	JACALITO-LV	0.55	1.22	RN	Fresno		No NQC - Pmax	Market
PG&E	ZZZ_New Unit	365697	Q1158B	0.36	300.00	1	Fresno		No NQC - est. data	Battery
PG&E	ZZZ_New Unit	365524	Q1036SPV	0.36	41.42	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34688	Q272	0.36	33.21	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365675	Q1128-5S	0.36	13.50	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365673	Q1128-4S	0.36	13.50	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34335	Q723	0.32	13.50	1	Fresno	Borden	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365604	Q1028Q10	0.36	5.40	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365663	Q1127SPV	0.36	5.40	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365504	Q632BSPV	0.55	5.00	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34649	Q965SPV	0.36	3.65	1	Fresno	Herndon	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365694	Q1158S	0.36	0.00	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34603	JGBSWLT	12.5	0.00	ST	Fresno	Herndon	Energy Only	Market
PG&E	ZZZZZ_CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	0.00	RT	Fresno		Retired	Market
PG&E	ZZZZZ_COLGA1_6_SHELL W	34654	COLNGAGN	9.11	0.00	1	Fresno	Coalinga	Retired	Net Seller
PG&E	ZZZZZ_GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	RT	Fresno	Coalinga	Retired	Market
PG&E	ZZZZZ_INTTRB_6_UNIT	34342	INT.TURB	9.11	0.00	1	Fresno		Retired	Market

PG&E	ZZZZZ_MENBIO_6_UNIT	34334	BIO PWR	9.11	0.00	1	Fresno	Panoche 115 kV, Wilson 115 kV	Retired	QF/Selfgen
PG&E	BRDGVL_7_BAKER				0.00		Humboldt		Not modeled Aug NQC	Net Seller
PG&E	FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	12.65	1	Humboldt		Aug NQC	Net Seller
PG&E	FTSWRD_6_TRFORK				0.15		Humboldt		Not modeled Aug NQC	Market
PG&E	FTSWRD_7_QFUNTS				0.00		Humboldt		Not modeled Aug NQC	QF/Selfgen
PG&E	GRSCRK_6_BGCKWW				0.00		Humboldt		Not modeled Aug NQC	Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.69	3	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.32	1	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.22	4	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	15.85	2	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.62	8	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.33	6	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.33	9	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.24	7	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.14	5	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	15.95	10	Humboldt			Market
PG&E	HUMBSB_1_QF				0.00		Humboldt		Not modeled Aug NQC	QF/Selfgen
PG&E	KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt		Aug NQC	Net Seller
PG&E	LAPAC_6_UNIT	31158	LP SAMOA	12.5	0.00	1	Humboldt			Market
PG&E	LOWGAP_1_SUPHR				0.00		Humboldt		Not modeled Aug NQC	Market
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	5.82	1	Humboldt		Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	5.82	2	Humboldt		Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31153	PAC.LUMB	2.4	3.49	3	Humboldt		Aug NQC	Net Seller
PG&E	ZZZZZ_BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	Humboldt		Retired	Market
PG&E	7STDRD_1_SOLAR1	35065	7STNDRD_1	21	5.40	FW	Kern	South Kern PP, Kern Oil	Aug NQC	Solar
PG&E	ADOBEE_1_SOLAR	35021	Q622B	34.5	5.40	1	Kern	South Kern PP	Aug NQC	Solar
PG&E	BDGRCK_1_UNITS	35029	BADGERCK	13.8	40.20	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	BEARMT_1_UNIT	35066	PSE-BEAR	13.8	44.00	1	Kern	South Kern PP, Westpark	Aug NQC	Net Seller

PG&E	BKRFLD_2_SOLAR1				0.37		Kern	South Kern PP	Not modeled Aug NQC	Solar
PG&E	DEXZEL_1_UNIT	35024	DEXEL +	13.8	17.78	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	DISCOV_1_CHEVRN	35062	DISCOVRY	13.8	2.58	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	DOUBLC_1_UNITS	35023	DOUBLE C	13.8	49.50	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KERNFT_1_UNITS	35026	KERNFRNT	9.11	48.60	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	LAMONT_1_SOLAR1	35019	REGULUS	0.4	16.20	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR2	35092	Q744G4	0.38	5.40	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR3	35087	Q744G3	0.4	4.05	3	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR4	35059	Q744G2	0.4	21.38	2	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR5	35054	Q744G1	0.4	4.50	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.1	42.50	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	MAGUND_1_BKISR1				0.27		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Solar
PG&E	MAGUND_1_BKSSR2				1.42		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Solar
PG&E	MTNPOS_1_UNIT	35036	MT POSO	13.8	34.35	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	OLDRIV_6_BIOGAS				1.69		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRIV_6_CESDBM				0.90		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRIV_6_LKVBM1				0.91		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRV1_6_SOLAR	35091	OLD_RVR1	12.5	5.40	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar
PG&E	SIERRA_1_UNITS	35027	HISIERRA	9.11	49.57	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR1	35089	S_KERN	0.48	5.40	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar
PG&E	SKERN_6_SOLAR2	365563	Q885	0.36	2.70	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar

PG&E	VEDDER_1_SEKERN	35046	SEKR	9.11	2.19	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	ZZZZZ_KRNCNY_6_UNIT	35018	KERNCNYN	11	0.00	1	Kern	South Kern PP, Kern 70 kV	Retired	Market
PG&E	ZZZZZ_OILDAL_1_UNIT 1	35028	OILDALE	9.11	0.00	RT	Kern	South Kern PP, Kern Oil	Retired	Net Seller
PG&E	ZZZZZ_RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.1	0.00	1	Kern	South Kern PP, Kern 70 kV	Retired	Market
PG&E	ZZZZZ_ULTOGL_1_POSO	35035	ULTR PWR	9.11	0.00	1	Kern	South Kern PP, Kern Oil	Retired	QF/Selfgen
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	NCNB	Eagle Rock, Fulton		Market
PG&E	CLOVDL_1_SOLAR				0.41		NCNB	Eagle Rock, Fulton	Not modeled Aug NQC	Solar
PG&E	CSTOGA_6_LNDFIL				0.00		NCNB	Fulton	Not modeled Energy Only	Market
PG&E	FULTON_1_QF				0.06		NCNB	Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	GEYS11_7_UNIT11	31412	GEYSER11	13.8	68.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	NCNB	Fulton		Market
PG&E	GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	NCNB			Market
PG&E	GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	NCNB	Fulton		Market
PG&E	GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	NCNB	Fulton		Market
PG&E	GEYS17_2_BOTRCK				8.23	1	NCNB	Fulton		Market
PG&E	GEYS17_7_UNIT17	31422	GEYSER17	13.8	56.00	1	NCNB	Fulton		Market
PG&E	GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	NCNB			Market
PG&E	GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	NCNB			Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	2	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	NCNB	Eagle Rock, Fulton		Market
PG&E	GYSRVL_7_WSPRNG				1.48		NCNB	Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	HILAND_7_YOLOWD				0.00		NCNB	Eagle Rock, Fulton	Not Modeled. Energy Only	Market
PG&E	IGNACO_1_QF				0.01		NCNB		Not modeled Aug NQC	QF/Selfgen
PG&E	INDVLY_1_UNITS	31436	INDIAN V	9.1	0.79	1	NCNB	Eagle Rock, Fulton	Aug NQC	Net Seller
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.11	1	NCNB	Fulton	Aug NQC	Market

PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.11	2	NCNB	Fulton	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	0.93	3	NCNB	Fulton	Aug NQC	Market
PG&E	NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	NCNB		Aug NQC	MUNI
PG&E	NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	NCNB		Aug NQC	MUNI
PG&E	NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	NCNB	Fulton	Aug NQC	MUNI
PG&E	NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	NCNB	Fulton	Aug NQC	MUNI
PG&E	NOVATO_6_LNDFL				3.56		NCNB		Not modeled Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	1.32	1	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.60	3	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.60	4	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_7_VECINO				0.01		NCNB	Eagle Rock, Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	1	NCNB			Market
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	2	NCNB			Market
PG&E	SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	47.00	1	NCNB			Market
PG&E	SNMALF_6_UNITS	31446	SONMA LF	9.1	3.12	1	NCNB	Fulton	Aug NQC	QF/Selfgen
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	1.21	2	NCNB	Eagle Rock, Fulton	Aug NQC	MUNI
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	0.49	1	NCNB	Eagle Rock, Fulton	Aug NQC	MUNI
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	2	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_WDFRDF_2_UNITS	31404	WEST FOR	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_WDFRDF_2_UNITS	31404	WEST FOR	13.8	0.00	2	NCNB	Fulton	Retired	Market
PG&E	ZZZZZZ_GEYS17_2_BOTRC K	31421	BOTTLERK	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ALLGNY_6_HYDRO1				0.03		Sierra		Not modeled Aug NQC	Market
PG&E	APLHIL_1_SLABCK				0.00	1	Sierra	South of Rio Oso, South of Palermo	Not modeled Energy Only	Market
PG&E	BANGOR_6_HYDRO				1.00		Sierra		Not modeled Aug NQC	Market
PG&E	BELDEN_7_UNIT 1	31784	BELDEN	13.8	119.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	BIOMAS_1_UNIT 1	32156	WOODLAND	9.11	24.31	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Net Seller

PG&E	BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.68		Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	BOGUE_1_UNITA1	32451	FREC	13.8	47.60	1	Sierra	Bogue, Drum-Rio Oso	Aug NQC	Market
PG&E	BOWMN_6_HYDRO	32480	BOWMAN	9.11	2.54	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	BUCKCK_2_HYDRO				0.04		Sierra	South of Palermo	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_OAKFLT				1.30		Sierra	South of Palermo	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	30.63	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	26.62	2	Sierra	South of Palermo	Aug NQC	Market
PG&E	CAMPFW_7_FARWST	32470	CMP.FARW	9.11	2.90	1	Sierra		Aug NQC	MUNI
PG&E	CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	42.00	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	Sierra		Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	Sierra		Aug NQC	MUNI
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	35.54	2	Sierra	South of Palermo	Aug NQC	Market
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	34.86	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	DAVIS_1_SOLAR1				0.00		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Solar
PG&E	DAVIS_1_SOLAR2				0.00		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Solar
PG&E	DAVIS_7_MNMETH				1.76		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	DEADCK_1_UNIT	31862	DEADWOOD	9.11	0.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	DEERCR_6_UNIT 1	32474	DEER CRK	9.11	2.98	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	15.64	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market

PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.26	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_UNIT 5	32454	DRUM 5	13.8	50.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo		Market
PG&E	ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo		Market
PG&E	FMEADO_6_HELLHL	32486	HELLHOLE	9.11	0.43	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.00	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	GRIDLY_6_SOLAR	38054	GRIDLEY	60	0.00	1	Sierra	Pease	Energy Only	Solar
PG&E	GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	38.99	1	Sierra	Pease, Drum-Rio Oso	Aug NQC	QF/Selfgen
PG&E	HALSEY_6_UNIT	32478	HALSEY F	9.11	13.50	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.05	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	QF/Selfgen
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.04	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	QF/Selfgen
PG&E	HIGGNS_1_COMBIE				0.22		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	HIGGNS_7_QFUNTS				0.24		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	QF/Selfgen

PG&E	KELYRG_6_UNIT	31834	KELLYRDG	9.11	11.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	LIVEOK_6_SOLAR				0.14		Sierra	Pease	Not modeled Aug NQC	Solar
PG&E	LODIEC_2_PL1X2	38123	LODI CT1	18	199.03	1	Sierra	South of Rio Oso, South of Palermo		MUNI
PG&E	LODIEC_2_PL1X2	38124	LODI ST1	18	103.55	1	Sierra	South of Rio Oso, South of Palermo		MUNI
PG&E	MDFKRL_2_PROJCT	32458	RALSTON	13.8	82.13	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.94	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.94	2	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	NAROW1_2_UNIT	32466	NARROWS1	9.1	12.00	1	Sierra		Aug NQC	Market
PG&E	NAROW2_2_UNIT	32468	NARROWS2	9.1	28.51	1	Sierra		Aug NQC	MUNI
PG&E	NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.51	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	OROVIL_6_UNIT	31888	OROVLLE	9.11	7.50	1	Sierra	Drum-Rio Oso	Aug NQC	Market
PG&E	OXBOW_6_DRUM	32484	OXBOW F	9.11	3.62	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	PLACVL_1_CHILIB	32510	CHILIBAR	4.2	8.40	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	PLACVL_1_RCKCRE				1.20		Sierra	South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	PLSNTG_7_LNCLND	32408	PLSNT GR	60	3.09		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	57.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.90	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RIOOSO_1_QF				1.15		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	QF/Selfgen
PG&E	ROLLIN_6_UNIT	32476	ROLLINSF	9.11	13.50	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	SLYCRK_1_UNIT 1	31832	SLY.CR.	9.11	13.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI

PG&E	SPAULD_6_UNIT 3	32472	SPAULDG	9.11	1.59	3	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	7.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.40	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.93	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	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		MUNI
PG&E	ULTRCK_2_UNIT	32500	ULTR RCK	9.11	22.83	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	60.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	WHEATL_6_LNDFIL	32350	WHEATLND	60	3.55		Sierra		Not modeled Aug NQC	Market
PG&E	WISE_1_UNIT 1	32512	WISE	12	14.50	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	WISE_1_UNIT 2	32512	WISE	12	3.20	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	YUBACT_1_SUNSWT	32494	YUBA CTY	9.11	49.97	1	Sierra	Pease, Drum-Rio Oso	Aug NQC	Net Seller
PG&E	YUBACT_6_UNITA1	32496	YCEC	13.8	47.60	1	Sierra	Pease, Drum-Rio Oso		Market
PG&E	ZZ_NA	32162	RIV.DLTA	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Palermo	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	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	365936	Q653FSPV	0.48	2.46	1	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365940	Q653FSPV	0.48	2.46	2	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Solar

PG&E	ZZZ_New Unit	365938	Q653FC6B	0.48	0.00	2	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Battery
PG&E	ZZZZZ_GOLDHL_1_QF				0.00		Sierra	South of Rio Oso, South of Palermo	Retired	QF/Selfgen
PG&E	ZZZZZ_GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	0.00	1	Sierra	Bogue, Drum-Rio Oso	Retired	Market
PG&E	ZZZZZ_GRNLF1_1_UNITS	32491	GRNLEAF1	13.8	0.00	2	Sierra	Bogue, Drum-Rio Oso	Retired	Market
PG&E	ZZZZZ_KANAKA_1_UNIT				0.00		Sierra	Drum-Rio Oso	Retired	MUNI
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	1	Sierra	Drum-Rio Oso	Retired	QF/Selfgen
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	2	Sierra	Drum-Rio Oso	Retired	QF/Selfgen
PG&E	BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.92	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.92	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.92	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CRWCKS_1_SOLAR1	34051	Q539	34.5	0.00	1	Stockton	Tesla-Bellota	Energy Only	Solar
PG&E	DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	FROGTN_1_UTICAA				1.40		Stockton	Tesla-Bellota, Stanislaus	Not Modeled Aug NQC	Market
PG&E	FROGTN_1_UTICAM				2.37		Stockton	Tesla-Bellota, Stanislaus	Not Modeled Aug NQC	Market
PG&E	LOCKFD_1_BEARCK				0.41		Stockton	Tesla-Bellota	Not Modeled Aug NQC	Solar
PG&E	LOCKFD_1_KSOLAR				0.27		Stockton	Tesla-Bellota	Not Modeled Aug NQC	Solar
PG&E	LODI25_2_UNIT 1	38120	LODI25CT	9.11	23.80	1	Stockton	Lockeford		MUNI
PG&E	MANTEC_1_ML1SR1				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Solar
PG&E	PEORIA_1_SOLAR				0.41		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Solar
PG&E	PHOENX_1_UNIT				0.84		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	138.11	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	85.70	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	85.70	1	Stockton	Tesla-Bellota		Market

PG&E	SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	12.88	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	SPIFBD_1_PL1X2	34055	SPISONORA	13.8	5.67	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.01	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	18.26	1	Stockton	Tesla-Bellota	Aug NQC	Net Seller
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	7.41	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	6.58	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	4.86	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	Market
PG&E	VLYHOM_7_SSJID				0.65		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	MUNI
PG&E	ZZZ_New Unit	365684	Q1103		10.80	1	Stockton	Tesla-Bellota	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34053	Q539		0.00	1	Stockton	Tesla-Bellota	Energy Only	Solar
PG&E	ZZZ_New Unit	365556	SAFEWAYB		0.00	RN	Stockton	Tesla-Bellota	Energy Only	Market
PG&E	ZZZZZ_FROGTN_7_UTICA				0.00		Stockton	Tesla-Bellota, Stanislaus	Retired	Market
PG&E	ZZZZZ_STOKCG_1_UNIT 1	33814	INGREDION	12.5	0.00	RN	Stockton	Tesla-Bellota	Retired	QF/Selfgen
PG&E	ZZZZZZ_NA	33830	GEN.MILL	9.11	0.00	1	Stockton	Lockeford	Retired	QF/Selfgen
SCE	ACACIA_6_SOLAR	29878	ACACIA_G	0.48	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	ALAMO_6_UNIT	25653	ALAMO SC	13.8	11.36	1	BC/Ventura		Aug NQC	MUNI
SCE	BGSKYN_2_AS2SR1	29774	ANTLOP2_G1	0.42	28.35	EQ	BC/Ventura		Aug NQC	Solar
SCE	BGSKYN_2_ASPSR2				27.00		BC/Ventura		Aug NQC	Solar
SCE	BGSKYN_2_BS3SR3				5.40		BC/Ventura		Aug NQC	Solar
SCE	BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	92.02	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	92.02	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	51.18	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.99	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.80	42	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.60	41	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	43.30	82	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	35.92	5	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	35.43	4	BC/Ventura	Rector, Vestal	Aug NQC	Market

SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.44	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.44	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	33.46	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.71	4	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	24.01	81	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.26	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.26	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.58	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.39	4	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.40	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.21	6	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.73	5	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.45	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_7_DAM7				0.00		BC/Ventura	Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGCRK_7_MAMRES				0.00		BC/Ventura	Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGSKY_2_BSKSR6	29734	BSKY G BC	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_BSKSR7	29737	BSKY G WABS	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_BSKSR8	29740	BSKY G ABSR	0.38	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR1	29704	BSKY G SMR	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR2	29744	BSKY_G_ESC	0.42	34.41	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR3	29725	BSKY_G_BD	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR4	29701	BSKY_G_BA	0.42	17.26	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR5	29731	BSKY_G_BB	0.42	1.35	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR6	29728	BSKY_G_SOLV	0.42	22.95	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR7	29731	BSKY_G_ADSR	0.42	13.50	1	BC/Ventura		Aug NQC	Solar
SCE	CEDUCR_2_SOLAR1	25049	DUCOR1	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR2	25052	DUCOR2	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR3	25055	DUCOR3	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR4	25058	DUCOR4	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	DELSUR_6_BSOLAR	24411	DELSUR_DIST	66	0.81	1	BC/Ventura		Aug NQC	Solar
SCE	DELSUR_6_CREST	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	DELSUR_6_DRYFRB	24411	DELSUR_DIST	66	1.35	1	BC/Ventura		Aug NQC	Market
SCE	DELSUR_6_SOLAR1	24411	DELSUR_DIST	66	1.76	2	BC/Ventura		Aug NQC	Solar
SCE	DELSUR_6_SOLAR4	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Solar

SCE	DELSUR_6_SOLAR5	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Solar
SCE	EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	BC/Ventura	Rector, Vestal		Market
SCE	EDMONS_2_NSPIN	25605	EDMON1AP	14.4	16.86	1	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25606	EDMON2AP	14.4	16.86	2	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	3	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	4	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	5	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	6	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	7	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	8	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	9	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	10	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	11	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	12	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	13	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	14	BC/Ventura		Pumps	MUNI
SCE	GLDFGR_6_SOLAR1	25079	PRIDE B G	0.64	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	GLDFGR_6_SOLAR2	25169	PRIDE C G	0.64	3.08	1	BC/Ventura		Aug NQC	Solar
SCE	GLOW_6_SOLAR	29896	APPINV	0.42	0.00	EQ	BC/Ventura		Energy Only	Solar
SCE	GOLETA_2_QF	25335	GOLETA_DIST	66	0.04	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	QF/Selfgen
SCE	GOLETA_6_ELLWOD	29004	ELLWOOD	13.8	54.00	1	BC/Ventura	S.Clara, Moorpark, Goleta		Market
SCE	GOLETA_6_EXGEN	24362	EXGEN2	13.8	0.00	G1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC - Currently out of service	QF/Selfgen
SCE	GOLETA_6_EXGEN	24326	EXGEN1	13.8	0.00	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC - Currently out of service	QF/Selfgen
SCE	GOLETA_6_GAVOTA	25335	GOLETA_DIST	66	0.00	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	Market
SCE	GOLETA_6_TAJIGS	25335	GOLETA_DIST	66	2.84	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	Market
SCE	LEBECS_2_UNITS	29053	PSTRIAS1	18	173.86	S1	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29051	PSTRIAG1	18	168.90	G1	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29052	PSTRIAG2	18	168.90	G2	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29054	PSTRIAG3	18	168.90	G3	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29055	PSTRIAS2	18	84.45	S2	BC/Ventura		Aug NQC	Market

SCE	LITLRK_6_GBCSR1	24419	LTLRCK_DIST	66	0.81	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SEPV01	24419	LTLRCK_DIST	66	0.00	AS	BC/Ventura		Energy Only	Market
SCE	LITLRK_6_SOLAR1	24419	LTLRCK_DIST	66	1.35	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR2	24419	LTLRCK_DIST	66	0.54	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR3	24419	LTLRCK_DIST	66	0.54	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR4	24419	LTLRCK_DIST	66	0.81	AS	BC/Ventura		Aug NQC	Solar
SCE	LNCSTR_6_CREST				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	BC/Ventura	S.Clara, Moorpark		Market
SCE	MOORPK_2_CALABS	25081	WDT251	13.8	4.57	EQ	BC/Ventura	Moorpark	Aug NQC	Market
SCE	MOORPK_6_QF				0.80		BC/Ventura	Moorpark	Not modeled Aug NQC	Market
SCE	NEENCH_6_SOLAR	29900	ALPINE_G	0.48	17.82	EQ	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_CREST				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	OASIS_6_GBDSR4	24421	OASIS_DIST	66	0.81	1	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_SOLAR1	25095	SOLARISG2	0.2	0.00	EQ	BC/Ventura		Energy Only	Solar
SCE	OASIS_6_SOLAR2	25075	SOLARISG	0.2	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_SOLAR3				0.00		BC/Ventura		Not modeled Energy Only	Solar
SCE	OMAR_2_UNIT 1	24102	OMAR 1G	13.8	70.30	1	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 2	24103	OMAR 2G	13.8	71.24	2	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 3	24104	OMAR 3G	13.8	74.03	3	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 4	24105	OMAR 4G	13.8	81.44	4	BC/Ventura			Net Seller
SCE	ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	BC/Ventura	Moorpark	Retired by 2025	Market
SCE	ORMOND_7_UNIT 2	24108	ORMOND2G	26	750.00	2	BC/Ventura	Moorpark	Retired by 2025	Market
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	1	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	2	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	3	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	4	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	5	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	6	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	7	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	8	BC/Ventura		Pumps	MUNI
SCE	PLAINV_6_BSOLAR	29917	SSOLAR)GRWK S	0.8	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PLAINV_6_DSOLAR	29914	WADR_PV	0.42	2.70	1	BC/Ventura		Aug NQC	Solar

SCE	PLAINV_6_NLRSR1	29921	NLR_INVTR	0.42	0.00	1	BC/Ventura		Aug NQC	Solar
SCE	PLAINV_6_SOLAR3	25089	CNTRL ANT G	0.42	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PLAINV_6_SOLARC	25086	SIRA SOLAR G	0.8	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PMDLET_6_SOLAR1				2.70		BC/Ventura		Not modeled Aug NQC	Solar
SCE	RECTOR_2_CREST	25333	RECTOR_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_KAWEAH	25333	RECTOR_DIST	66	1.74	S2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_KAWH 1	24370	KAWGEN	13.8	0.52	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_QF	25333	RECTOR_DIST	66	3.94	S1	BC/Ventura	Rector, Vestal	Aug NQC	QF/Selfgen
SCE	RECTOR_2_TFDBM1				0.00		BC/Ventura	Rector, Vestal	Energy Only	Market
SCE	RECTOR_7_TULARE	25333	RECTOR_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	REDMAN_2_SOLAR	24425	REDMAN_DIST	66	1.01	AS	BC/Ventura		Aug NQC	Solar
SCE	REDMAN_6_AVSSR1				0.81		BC/Ventura		Aug NQC	Solar
SCE	ROSMND_6_SOLAR	24434	ROSAMOND_DIS	66	0.81	AS	BC/Ventura		Aug NQC	Solar
SCE	RSMSLR_6_SOLAR1	29984	DAWNGEN	0.8	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	RSMSLR_6_SOLAR2	29888	TWILGHTG	0.8	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	SAUGUS_6_CREST				0.00		BC/Ventura		Energy Only	Market
SCE	SAUGUS_6_MWDFTH	25336	SAUGUS_MWD	66	5.40	S1	BC/Ventura		Aug NQC	MUNI
SCE	SAUGUS_6_QF	24135	SAUGUS	66	0.70		BC/Ventura		Not modeled Aug NQC	QF/Selfgen
SCE	SAUGUS_7_CHIQCN	24135	SAUGUS	66	5.63		BC/Ventura		Not modeled Aug NQC	Market
SCE	SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.34		BC/Ventura		Not modeled Aug NQC	QF/Selfgen
SCE	SHUTLE_6_CREST	24426	SHUTTLE_DIST	66	0.00	AS	BC/Ventura		Energy Only	Market
SCE	SNCLRA_2_HOWLNG	25080	SANTACLR_DIS	13.8	8.72	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_SPRHYD	25080	SANTACLR_DIS	13.8	0.18	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_UNIT	29952	CAMGEN	13.8	27.50	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_UNIT1	24159	WILLAMET	3.8	15.63	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_6_OXGEN	24110	OXGEN	13.8	35.38	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_PROCGN	24119	PROCGEN	13.8	45.47	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_QF	25080	SANTACLR_DIS	13.8	0.00	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SPRGVL_2_CREST	25334	SPRNGVL_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Energy Only	Market
SCE	SPRGVL_2_QF	25334	SPRNGVL_DIST	66	0.18	S1	BC/Ventura	Rector, Vestal	Aug NQC	QF/Selfgen
SCE	SPRGVL_2_TULE	25334	SPRNGVL_DIST	66	0.00	S2	BC/Ventura	Rector, Vestal	Aug NQC	Market

SCE	SPRGVL_2_TULESC	25334	SPRNGVL_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	1	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	2	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	3	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	4	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	5	BC/Ventura		Aug NQC	Market
SCE	SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	77.41	1	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 2	24144	SYCCYN2G	13.8	80.00	2	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 3	24145	SYCCYN3G	13.8	80.00	3	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 4	24146	SYCCYN4G	13.8	80.00	4	BC/Ventura		Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.80	D1	BC/Ventura		Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.80	D2	BC/Ventura		Aug NQC	Net Seller
SCE	VESTAL_2_KERN	24372	KR 3-1	11	6.50	1	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_KERN	24373	KR 3-2	11	6.13	2	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_RTS042				0.00		BC/Ventura	Vestal	Not modeled Energy Only	Market
SCE	VESTAL_2_SOLAR1	25064	TULRESLR_1	0.39	5.40	1	BC/Ventura	Vestal	Aug NQC	Solar
SCE	VESTAL_2_SOLAR2	25065	TULRESLR_2	0.39	3.78	1	BC/Ventura	Vestal	Aug NQC	Solar
SCE	VESTAL_2_UNIT1				4.03		BC/Ventura	Vestal	Not modeled Aug NQC	Market
SCE	VESTAL_2_WELLHD	24116	WELLGEN	13.8	49.00	1	BC/Ventura	Vestal		Market
SCE	VESTAL_6_QF	29008	LAKEGEN	13.8	5.49	1	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	WARNE_2_UNIT	25651	WARNE1	13.8	20.79	1	BC/Ventura		Aug NQC	MUNI
SCE	WARNE_2_UNIT	25652	WARNE2	13.8	20.79	2	BC/Ventura		Aug NQC	MUNI
SCE	ZZ_NA	24340	CHARMIN	13.8	2.80	1	BC/Ventura	S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
SCE	ZZZ_New Unit	698508	WDT1519	66	100.00	EQ	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	699101	WDT1454	66	40.00	EQ	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	99739	GOLETA-DIST	66	30.00	EQ	BC/Ventura	S.Clara, Moorpark, Goleta	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	99740	S.CLARA-DIST	66	11.00	EQ	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	24127	S.CLARA	66	9.27	X8	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	24057	GOLETA	66	4.73	X8	BC/Ventura	S.Clara, Moorpark, Goleta	No NQC - Pmax	Battery

SCE	ZZZZZ_APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	BC/Ventura		Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	BC/Ventura		Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	BC/Ventura		Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	0.00	1	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	0.00	2	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 3	24222	MANDLY3G	16	0.00	3	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MOORPK_7_UNITA1	24098	MOORPARK	66	0.00		BC/Ventura	Moorpark	Retired	Market
SCE	ZZZZZ_PANDOL_6_UNIT	24113	PANDOL	13.8	0.00	1	BC/Ventura	Vestal	Retired	Market
SCE	ZZZZZ_PANDOL_6_UNIT	24113	PANDOL	13.8	0.00	2	BC/Ventura	Vestal	Retired	Market
SCE	ZZZZZ_SAUGUS_2_TOLAN D	24135	SAUGUS	66	0.00		BC/Ventura		Retired	Market
SCE	ZZZZZ_SAUGUS_6_PTCHG N	24118	PITCHGEN	13.8	0.00	D1	BC/Ventura		Retired	MUNI
SCE	ZZZZZ_VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	0.00	1	BC/Ventura	Vestal	Retired	QF/Selfgen
SCE	ALAMIT_2_PL1X3	24577	ALMT STG	18	251.66	S1	LA Basin	Western		Market
SCE	ALAMIT_2_PL1X3	24575	ALMT CTG1	18	211.52	G1	LA Basin	Western		Market
SCE	ALAMIT_2_PL1X3	24576	ALMT CTG2	18	211.52	G2	LA Basin	Western		Market
SCE	ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	LA Basin	Western	Retired by 2025	Market
SCE	ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	LA Basin	Western	Retired by 2025	Market
SCE	ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	LA Basin	Western	Retired by 2025	Market
SCE	ALTWD_1_QF	25635	ALTWIND	115	3.82	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ALTWD_1_QF	25635	ALTWIND	115	3.82	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	51.98	1	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24012	ARCO 2G	13.8	51.98	2	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24013	ARCO 3G	13.8	51.98	3	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24014	ARCO 4G	13.8	51.98	4	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24163	ARCO 5G	13.8	25.99	5	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24164	ARCO 6G	13.8	25.99	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	10.29	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	BUCKWD_1_NPALM1	25634	BUCKWIND	115	0.65		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	BUCKWD_1_QF	25634	BUCKWIND	115	3.47	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.28	W5	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CABZON_1_WINDA1	29290	CABAZON	33	8.61	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CAPWD_1_QF	25633	CAPWIND	115	4.11	QF	LA Basin	Eastern, Valley-Devers	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	Solar
SCE	CENTER_2_TECNG1				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	CENTER_6_PEAKER	29308	CTRPKGEN	13.8	47.11	1	LA Basin	Western		Market
SCE	CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	3.77	1	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	3.77	2	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHINO_2_APEBT1	25180	WDT1250BESS_	0.48	20.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	CHINO_2_JURUPA				0.00		LA Basin	Eastern	Not modeled Energy Only	Market
SCE	CHINO_2_QF				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	CHINO_2_SASOLR				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CHINO_2_SOLAR				0.27		LA Basin	Eastern	Not modeled	Solar

SCE	CHINO_2_SOLAR2				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CHINO_6_CIMGEN	24026	CIMGEN	13.8	26.00	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	CHINO_7_MILIKN	24024	CHINO	66	1.19		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	CORONS_2_SOLAR				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CORONS_6_CLRWTR	29338	CLRWTRCT	13.8	20.72	G1	LA Basin	Eastern		MUNI
SCE	CORONS_6_CLRWTR	29340	CLRWTRST	13.8	7.28	S1	LA Basin	Eastern		MUNI
SCE	DELAMO_2_SOLAR1				0.41		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR2				0.47		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR3				0.34		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR4				0.35		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR5				0.27		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR6				0.54		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLRC1				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	DELAMO_2_SOLRD				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	DEVERS_1_QF	25639	SEAWIND	115	0.92	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_QF	25632	TERAWND	115	0.76	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	Solar
SCE	DEVERS_1_SOLAR1				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_1_SOLAR2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_2_CS2SR4				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar

SCE	DEVERS_2_DHSPG2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DMDVLY_1_UNITS	25425	ESRP P2	6.9	3.00	8	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	36.95	3	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	36.95	4	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	27.72	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	27.72	2	LA Basin	Eastern	Aug NQC	MUNI
SCE	ELLIS_2_QF	24325	ORCOGEN	13.8	0.06	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	Not modeled Energy Only	Market
SCE	ETIWND_2_FONTNA	24055	ETIWANDA	66	0.21		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_2_RTS010	24055	ETIWANDA	66	0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS015	24055	ETIWANDA	66	0.81		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS017	24055	ETIWANDA	66	0.95		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS018	24055	ETIWANDA	66	0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS023	24055	ETIWANDA	66	0.68		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS026	24055	ETIWANDA	66	1.62		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS027	24055	ETIWANDA	66	0.54		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_SOLAR1				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_SOLAR2				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_SOLAR5				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_UNIT1	24071	INLAND	13.8	10.34	1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	47.39	1	LA Basin	Eastern		Market

SCE	ETIWND_6_MWDETI	25422	ETI MWDG	13.8	16.70	1	LA Basin	Eastern	Aug NQC	Market
SCE	GARNET_1_SOLAR	24815	GARNET	115	0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	GARNET_1_SOLAR2	24815	GARNET	115	1.08		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Solar
SCE	GARNET_1_UNITS	24815	GARNET	115	1.63	G1	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	1.28	G3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.56	G2	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_WIND	24815	GARNET	115	1.37		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_1_WINDS	24815	GARNET	115	4.73	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_DIFWD1	24815	GARNET	115	1.65		LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_HYDRO	24815	GARNET	115	0.76	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_WIND1	24815	GARNET	115	2.35		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND2	24815	GARNET	115	2.46		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND3	24815	GARNET	115	2.65		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND4	24815	GARNET	115	2.06		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND5	24815	GARNET	115	0.63		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WPMWD6	24815	GARNET	115	1.25		LA Basin	Eastern, Valley-Devers	Not modeled 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		Market

SCE	HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	LA Basin	Western		Market
SCE	HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	LA Basin	Western		Market
SCE	HINSON_6_CARBGN	24020	CARBGEN1	13.8	14.43	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.43	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	34.00	D1	LA Basin	Western	Aug NQC	Market
SCE	HNTGBH_2_PL1X3	24581	HUNTBCH CTG2	18	211,23	G2	LA Basin	Western		Market
SCE	HNTGBH_2_PL1X3	24582	HUNTBCH STG	18	251.34	S1	LA Basin	Western		Market
SCE	HNTGBH_2_PL1X3	24580	HUNTBCH CTG1	18	211.23	G1	LA Basin	Western		Market
SCE	HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	LA Basin	Western	Retired by 2025	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	LACIEN_2_VENICE	24337	VENICE	13.8	3.00	1	LA Basin	Western, El Nido	Aug NQC	MUNI
SCE	LAGBEL_6_QF	29951	REFUSE	13.8	0.35	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				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_LNDFL				0.81		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_MLBBTA	25185	WDT1425_G1	0.48	10.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	MIRLOM_2_MLBBTB	25186	WDT1426_G2	0.48	10.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	MIRLOM_2_ONTARO				1.49		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS032				0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS033				0.27		LA Basin	Eastern	Not modeled Aug NQC	Market

SCE	MIRLOM_2_TEMESC				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	LA Basin	Eastern		Market
SCE	MIRLOM_7_MWDLKM	24210	MIRALOMA	66	1.80		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	3.20	1	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	3.20	2	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	3.20	3	LA Basin	Eastern	Aug NQC	Market
SCE	MTWIND_1_UNIT 1	29060	MOUNTWND	115	9.32	S1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 2	29060	MOUNTWND	115	4.66	S2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 3	29060	MOUNTWND	115	4.71	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	7.16	S1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C2	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C3	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C4	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_QF	24211	OLINDA	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	OLINDA_7_BLKSND	24211	OLINDA	66	0.36		LA Basin	Western	Not modeled Aug NQC	Market
SCE	OLINDA_7_LNDFIL	24211	OLINDA	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_ONTARO	24111	PADUA	66	0.35		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_SOLAR1	24111	PADUA	66	0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	PADUA_6_MWDSDM	24111	PADUA	66	2.60		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	PADUA_6_QF	24111	PADUA	66	0.39		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_7_SDIMAS	24111	PADUA	66	1.05		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	PANSEA_1_PANARO	25640	PANAERO	115	6.30	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	PWEST_1_UNIT	24815	GARNET	115	0.44	PC	LA Basin	Western	Aug NQC	Market

SCE	REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	LA Basin	Western	Retired by 2025	Market
SCE	REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	LA Basin	Western	Retired by 2025	Market
SCE	REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	LA Basin	Western	Retired by 2025	Market
SCE	RENWD_1_QF	25636	RENWIND	115	1.33	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RENWD_1_QF	25636	RENWIND	115	1.32	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RVSIDE_2_RERCU3	24299	RERC2G3	13.8	49.00	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_2_RERCU4	24300	RERC2G4	13.8	49.00	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_SOLAR1	24244	SPRINGEN	13.8	2.03		LA Basin	Eastern	Not modeled Aug NQC	Solar
SCE	RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	LA Basin	Eastern		Market
SCE	SANITR_6_UNITS	24324	SANIGEN	13.8	0.84	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	SANTGO_2_LNDFL1	24341	COYGEN	13.8	18.65	1	LA Basin	Western	Aug NQC	Market
SCE	SANTGO_2_MABBT1	25192	WDT1406_G	0.48	2.00	1	LA Basin	Western	Aug NQC	Battery
SCE	SANWD_1_QF	25646	SANWIND	115	3.26	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SANWD_1_QF	25646	SANWIND	115	3.26	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SBERDO_2_PSP3	24923	MNTV-ST1	18	257.82	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP3	24921	MNTV-CT1	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP3	24922	MNTV-CT2	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24926	MNTV-ST2	18	257.82	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24924	MNTV-CT3	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24925	MNTV-CT4	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_QF	24214	SANBRDNO	66	0.14		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_2_REDLND	24214	SANBRDNO	66	0.54		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market

SCE	SBERDO_2_RTS005	24214	SANBRDNO	66	0.68		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS007	24214	SANBRDNO	66	0.68		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS011	24214	SANBRDNO	66	0.95		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS013	24214	SANBRDNO	66	0.95		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS016	24214	SANBRDNO	66	0.41		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS048	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers	Not modeled Energy Only	Market
SCE	SBERDO_2_SNTANA	24214	SANBRDNO	66	0.30		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_6_MILLCK	24214	SANBRDNO	66	1.09		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SENTNL_2_CTG1	29101	SENTINEL_G1	13.8	103.76	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG2	29102	SENTINEL_G2	13.8	95.34	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG3	29103	SENTINEL_G3	13.8	96.85	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG4	29104	SENTINEL_G4	13.8	102.47	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG5	29105	SENTINEL_G5	13.8	103.81	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG6	29106	SENTINEL_G6	13.8	100.99	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG7	29107	SENTINEL_G7	13.8	97.06	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG8	29108	SENTINEL_G8	13.8	101.80	1	LA Basin	Eastern, Valley-Devers		Market
SCE	TIFFNY_1_DILLON	29021	WINTEC6	115	9.45	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TRNSWD_1_QF	25637	TRANWIND	115	8.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TULEWD_1_TULWD1				26.80		LA Basin	Eastern, Valley-Devers	Not modeled 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	3.80		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_RTS044	24160	VALLEYSC	115	2.16		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	Solar
SCE	VALLEY_5_SOLAR2	25082	WDT786	34.5	5.40	EQ	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Solar
SCE	VENWD_1_WIND1	25645	VENWIND	115	1.98	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND2	25645	VENWIND	115	3.37	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND3	25645	VENWIND	115	4.00	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	24241	MALBRG3G	13.8	49.26	S3	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	VILLPK_2_VALLYV	24216	VILLA PK	66	4.10	DG	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	VILLPK_6_MWDYOR	24216	VILLA PK	66	3.60		LA Basin	Western	Not modeled Aug NQC	MUNI
SCE	VISTA_2_RIALTO	24901	VSTA	230	0.27		LA Basin	Eastern	Not modeled	Market
SCE	VISTA_2_RTS028	24901	VSTA	230	0.95		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	VISTA_6_QF	24902	VSTA	66	0.10		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	WALCRK_2_CTG1	29201	WALCRKG1	13.8	96.43	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG2	29202	WALCRKG2	13.8	96.91	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG3	29203	WALCRKG3	13.8	96.65	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG4	29204	WALCRKG4	13.8	96.49	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG5	29205	WALCRKG5	13.8	96.65	1	LA Basin	Western		Market
SCE	WALNUT_2_SOLAR				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	WALNUT_6_HILLGEN	24063	HILLGEN	13.8	32.97	D1	LA Basin	Western	Aug NQC	Net Seller
SCE	WALNUT_7_WCOVST	24157	WALNUT	66	5.37		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WHTWTR_1_WINDA1	29061	WHITEWTR	33	12.92	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	ZZZ_New	698082	ALMITOS B1A	0.42	50.00	1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	698083	ALMITOS B12	0.42	50.00	1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	97624	WH_STN_1	13.8	49.00	1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	97625	WH_STN_2	13.8	49.00	1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZZZ_ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	0.00	1	LA Basin	Western	Retired	Market
SCE	ZZZZZ_ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	0.00	2	LA Basin	Western	Retired	Market
SCE	ZZZZZ_ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	0.00	6	LA Basin	Western	Retired	Market
SCE	ZZZZZ_BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	0.00		LA Basin	Western	Retired	MUNI
SCE	ZZZZZ_CENTER_2_QF	29953	SIGGEN	13.8	0.00	D1	LA Basin	Western	Retired	QF/Selfgen
SCE	ZZZZZ_CHINO_6_SMPPAP	24140	SIMPSON	13.8	0.00	D1	LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_ETIWND_7_MIDVLY	24055	ETIWANDA	66	0.00		LA Basin	Eastern	Retired	QF/Selfgen

SCE	ZZZZZ_ETIWND_7_UNIT 3	24052	MTNVIST3	18	0.00	3	LA Basin	Eastern	Retired	Market
SCE	ZZZZZ_ETIWND_7_UNIT 4	24053	MTNVIST4	18	0.00	4	LA Basin	Eastern	Retired	Market
SCE	ZZZZZ_HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	0.00	1	LA Basin	Western	Retired	Market
SCE	ZZZZZ_INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	0.00	1	LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	0.00	1	LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_LAGBEL_2_STG1				0.00		LA Basin	Western	Retired	Market
SCE	ZZZZZ_MIRLOM_6_DELGEN	29339	DELGEN	13.8	0.00	1	LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_REDOND_7_UNIT 7	24123	REDON7 G	20	0.00	7	LA Basin	Western	Retired	Market
SCE	ZZZZZ_RHONDO_2_QF	24213	RIOHONDO	66	0.00	DG	LA Basin	Western	Retired	QF/Selfgen
SCE	ZZZZZ_RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		LA Basin	Western	Retired	Net Seller
SCE	ZZZZZ_VALLEY_7_BADLND	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_VALLEY_7_UNITA1	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_WALNUT_7_WCOVCT	24157	WALNUT	66	0.00		LA Basin	Western	Retired	Market
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	51.25	1	SD-IV	San Diego, Border		Market
SDG&E	BREGGO_6_DEGRSL	22085	BORREGO	12.5	1.70	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	BREGGO_6_SOLAR	22082	BR GEN1	0.21	7.02	1	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CARLS1_2_CARCT1	22783	EA5 REPOWER1	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22784	EA5 REPOWER2	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22786	EA5 REPOWER4	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22788	EA5 REPOWER3	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS2_1_CARCT1	22787	EA5 REPOWER5	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CCRITA_7_RPPCHF	22124	CHCARITA	138	3.60	1	SD-IV	San Diego	Aug NQC	Market

SDG&E	CHILLS_1_SYCENG	22120	CARLTNHS	138	0.62	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	33.75	1	SD-IV		Aug NQC	Solar
SDG&E	CNTNLA_2_SOLAR2	23463	DW GEN3&4	0.33	0.00	2	SD-IV		Energy Only	Solar
SDG&E	CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.71	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	20.85	G1	SD-IV		Aug NQC	Solar
SDG&E	CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	16.68	G2	SD-IV		Aug NQC	Solar
SDG&E	CRELMN_6_RAMON1	22152	CREELMAN	69	0.54	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMON2	22152	CREELMAN	69	1.35	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMSR3				0.93		SD-IV	San Diego	Not modeled Aug NQC	Solar
SDG&E	CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	10.50	1	SD-IV	San Diego	Aug NQC	Wind
SDG&E	CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	17.55	G1	SD-IV		Aug NQC	Solar
SDG&E	CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	17.55	G2	SD-IV		Aug NQC	Solar
SDG&E	ELCAJN_6_EB1BT1	22208	EL CAJON	69	7.50	1	SD-IV	San Diego, El Cajon		Battery
SDG&E	ELCAJN_6_LM6K	23320	EC GEN2	13.8	48.10	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ELCAJN_6_UNITA1	22150	EC GEN1	13.8	45.42	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ENERSJ_2_WIND	23100	ECO GEN1 G1	0.69	32.57	G1	SD-IV		Aug NQC	Wind
SDG&E	ESCNDO_6_EB1BT1	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_EB2BT2	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_EB3BT3	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	1	SD-IV	San Diego		Market
SDG&E	ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.04	1	SD-IV	San Diego		Market
SDG&E	ESCO_6_GLMQF	22332	GOALLINE	69	36.41	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	54.00	1	SD-IV		Aug NQC	Solar
SDG&E	IVWEST_2_SOLAR1	23155	DU GEN1 G1	0.2	21.91	G1	SD-IV		Aug NQC	Solar
SDG&E	IVWEST_2_SOLAR1	23156	DU GEN1 G2	0.2	18.59	G2	SD-IV		Aug NQC	Solar
SDG&E	JACMSR_1_JACSR1	23352	ECO GEN2	0.55	5.40	1	SD-IV		Aug NQC	Solar
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		Connect to CENACE/CFE grid for the summer – not available for ISO BAA RA purpose	Market
SDG&E	LAROA2_2_UNITA1	22997	INTBCT	16	176.81	1	SD-IV			Market
SDG&E	LAROA2_2_UNITA1	22996	INTBST	18	145.19	1	SD-IV			Market
SDG&E	LILIAC_6_SOLAR	22404	LILIAC	69	0.81	DG	SD-IV	San Diego		Solar
SDG&E	MRGT_6_MEF2	22487	MEF_MR2	13.8	44.00	1	SD-IV	San Diego		Market
SDG&E	MRGT_6_MMAREF	22486	MEF_MR1	13.8	45.00	1	SD-IV	San Diego		Market
SDG&E	MSHGTS_6_MMARLF	22448	MESAHGTS	69	4.03	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MSSION_2_QF	22496	MISSION	69	0.70	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MURRAY_6_UNIT	22532	MURRAY	69	0.00		SD-IV	San Diego	Not modeled Energy Only	Market
SDG&E	OCTILO_5_WIND	23314	OCO GEN G1	0.69	27.83	G1	SD-IV		Aug NQC	Wind
SDG&E	OCTILO_5_WIND	23318	OCO GEN G2	0.69	27.83	G2	SD-IV		Aug NQC	Wind
SDG&E	OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	SD-IV	San Diego		Market
SDG&E	OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	1	SD-IV	San Diego		Market
SDG&E	OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22607	OTAYMST1	16	272.27	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	22605	OTAYMGT1	18	165.16	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	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	PIOPIC_2_CTG1	23162	PIO PICO CT1	13.8	111.30	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG2	23163	PIO PICO CT2	13.8	112.70	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG3	23164	PIO PICO CT3	13.8	112.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PRCTVY_1_MIGBT1				0.00		SD-IV	San Diego	Aug NQC	Battery
SDG&E	SAMPSN_6_KELCO1	22704	SAMPSON	12.5	0.85	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	SLRMS3_2_SRMSR1	23442	DW GEN2 G3A	0.6	40.50	1	SD-IV		Aug NQC	Solar
SDG&E	SLRMS3_2_SRMSR1	23443	DW GEN2 G3B	0.6	27.00	1	SD-IV		Aug NQC	Solar
SDG&E	SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	TERMEX_2_PL1X3	22981	TDM STG	21	280.13	1	SD-IV			Market

SDG&E	TERMEX_2_PL1X3	22982	TDM CTG2	18	156.44	1	SD-IV			Market
SDG&E	TERMEX_2_PL1X3	22983	TDM CTG3	18	156.44	1	SD-IV			Market
SDG&E	VLCNTR_6_VCSLR	22870	VALCNTR	69	0.63	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR1	22870	VALCNTR	69	0.68	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR2	22870	VALCNTR	69	1.35	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VSTAES_6_VESBT1	23541	ME GEN 1_BS1	0.64	5.50	1	SD-IV	San Diego	No NQC - est. data	Battery
SDG&E	VSTAES_6_VESBT1	23216	ME GEN 1_BS2	0.48	5.50	1	SD-IV	San Diego	No NQC - est. data	Battery
SDG&E	WISTRA_2_WRSSR1	23287	Q429_G1	0.31	27.00	1	SD-IV		Aug NQC	Solar
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	23710	Q1170_BESS	0.48	62.50	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23441	DW GEN6	0.42	40.58	1	SD-IV		No NQC - est. data	Solar
SDG&E	ZZZ_New Unit	22020	AVOCADO	69	40.00	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23544	Q1169_BESS1	0.4	35.00	C8	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23519	Q1169_BESS2	0.4	35.00	C8	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23412	Q1434_G	0.64	30.00	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22942	BUE GEN 1_G1	0.69	11.60	G1	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22945	BUE GEN 1_G2	0.69	11.60	G2	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22947	BUE GEN 1_G3	0.69	11.60	G3	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22256	ESCNDIDO	69	6.50	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22112	CAPSTRNO	138	5.90	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22112	CAPSTRNO	138	4.00	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23597	Q1175_BESS	0.48	0.00	1	SD-IV		Energy Only	Battery
SDG&E	ZZZ_New Unit	22404	LILAC	69	0.00	S2	SD-IV	San Diego	Energy Only	Battery
SDG&E	ZZZ_New Unit	22512	MONSRATE	69	0.00	S2	SD-IV	San Diego	Energy Only	Battery

SDG&E	ZZZZZ_CBRLLO_6_PLSTP1	22092	CABRILLO	69	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_DIVSON_6_NSQF	22172	DIVISION	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	SD-IV	San Diego, El Cajon	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA1	22233	ENCINA 1	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_NIMTG_6_NIQF	22576	NOISLMTR	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_OTAY_6_LNDFL5	22604	OTAY	69	0.00		SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_6_LNDFL6	22604	OTAY	69	0.00		SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_6_UNITB1	22604	OTAY	69	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_7_UNITC1	22604	OTAY	69	0.00	3	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_PTLOMA_6_NTCCGN	22660	POINTLMA	69	0.00	2	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_PTLOMA_6_NTCQF	22660	POINTLMA	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen

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Attachment 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 Factor (%)
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 Factor (%)
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

Attachment B – Effectiveness factors for procurement guidance

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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 – North Coast and North Bay

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

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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 Factor. (%)
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 – Sierra Overall

Effectiveness factors to the Table Mountain – Pease 60 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
32492	GRNLEAF2	1	17
32494	YUBA CTY	1	17
32496	YCEC	1	17
31794	WOODLEAF	1	6
31814	FORBSTWN	1	6
31832	SLY.CR.	1	6
31834	KELLYRDG	1	6
31888	OROVLENRG	1	6

Attachment B – Effectiveness factors for procurement guidance

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
32451	FREC	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32452	COLGATE2	1	5
32156	WOODLAND	1	4
32498	SPILINCF	1	4
32502	DTCHFLT2	1	4
32454	DRUM 5	1	3
32474	DEER CRK	1	3
32476	ROLLINSF	1	3
32484	OXBOW F	1	3
32504	DRUM 1-2	1	3
32504	DRUM 1-2	2	3
32506	DRUM 3-4	1	3
32506	DRUM 3-4	2	3
32464	DTCHFLT1	1	3
32480	BOWMAN	1	3
32488	HAYPRES+	1	3
32488	HAYPRES+	2	3
32472	SPAULDG	1	3
32472	SPAULDG	2	3

Attachment B – Effectiveness factors for procurement guidance

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
32472	SPAULDG	3	3
32462	CHI.PARK	1	3
32500	ULTR RCK	1	3
31784	BELDEN	1	3
31786	ROCK CK1	1	3
31788	ROCK CK2	1	3
31790	POE 1	1	3
31792	POE 2	1	3
31812	CRESTA	1	3
31812	CRESTA	2	3
31820	BCKS CRK	1	3
31820	BCKS CRK	2	3
32478	HALSEY F	1	2
32512	WISE	1	2
32460	NEWCSTLE	1	2
32510	CHILIBAR	1	2
32513	ELDRADO1	1	2
32514	ELDRADO2	1	2
32456	MIDLFORK	1	2
32456	MIDLFORK	2	2
32458	RALSTON	1	2
32486	HELLHOLE	1	2
32508	FRNCH MD	1	2

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
38114	STIG CC	1	1
38123	LODI CT1	1	1
38124	LODI ST1	1	1

Table – San Jose

Effectiveness factors to the Metcalf 230/115 kV transformer #1:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
35850	GLRY COG	1	25
35850	GLRY COG	2	25
35851	GROYPKR1	1	25
35852	GROYPKR2	1	25
35853	GROYPKR3	1	25
35623	SWIFT	BT	21
35863	CATALYST	1	20
36863	DVRaGT1	1	9
36864	DVRbGt2	1	9
36865	DVRaST3	1	9
36859	Laf300	2	9
36859	Laf300	1	9
36858	Gia100	1	8
36895	Gia200	1	8
35861	SJ-SCL W	1	8
35854	LECEFGT1	1	7
35855	LECEFGT2	1	7
35856	LECEFGT3	1	7
35857	LECEFGT4	1	7
35858	LECEFST1	1	7
35860	OLS-AGNE	1	7

Table – South Bay-Moss Landing

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

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)

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

36895	Gia200	1	7
35854	LECEFGT1	1	7
35855	LECEFGT2	1	7
35856	LECEFGT3	1	7
35857	LECEFGT4	1	7
35858	LECEFST1	1	7
35860	OLS-AGNE	1	7

Table – Ames/Pittsburg/Oakland

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

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
35304	RUSELCT1	1	10
35305	RUSELCT2	2	10
35306	RUSELST1	3	10
33469	OX_MTN	1	10
33469	OX_MTN	2	10
33469	OX_MTN	3	10
33469	OX_MTN	4	10
33469	OX_MTN	5	10
33469	OX_MTN	6	10
33469	OX_MTN	7	10
33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3

33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3
33113	LMECST1	1	3
33151	FOSTER W	1	2
33151	FOSTER W	2	2
33151	FOSTER W	3	2
33136	CCCSD	1	2
33141	SHELL 1	1	2
33142	SHELL 2	1	2
33143	SHELL 3	1	2
32900	CRCKTCOG	1	2
32910	UNOCAL	1	2
32910	UNOCAL	2	2
32910	UNOCAL	3	2
32920	UNION CH	1	2
32921	ChevGen1	1	2
32922	ChevGen2	1	2
32923	ChevGen3	3	2
32741	HILLSIDE_12	1	2
32901	OAKLND 1	1	1
32902	OAKLND 2	2	1
32903	OAKLND 3	3	1
38118	ALMDACT1	1	1
38119	ALMDACT2	1	1

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

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
32921	ChevGen1	1	17
32922	ChevGen2	1	17
32923	ChevGen3	3	17
32901	OAKLND 1	1	16
32902	OAKLND 2	1	16
32903	OAKLND 3	1	16
38118	ALMDACT1	1	16
38119	ALMDACT2	1	16
32920	UNION CH	1	16
32910	UNOCAL	1	15
32910	UNOCAL	2	15
32910	UNOCAL	3	15
33141	SHELL 1	1	10
33142	SHELL 2	1	10
33143	SHELL 3	1	10
33136	CCCSD	1	9
32900	CRCKTCOG	1	8
33151	FOSTER W	1	6
33151	FOSTER W	2	6
33151	FOSTER W	3	6
33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3
33113	LMECST1	1	3
33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3

Table – Greater Bay Area

Effectiveness factors to the Metcalf 500/230 kV Transformer #13:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
35881	MEC CTG1	1	40
35882	MEC CTG2	1	40
35883	MEC STG1	1	40

35859	HGST-LV	RN	36
35850	GLRY COG	1	30
35850	GLRY COG	2	30
35851	GROYPKR1	1	30
35852	GROYPKR2	1	30
35853	GROYPKR3	1	30
35623	SWIFT	BT	29
35863	CATALYST	1	28
33469	OX_MTN	1	22
33469	OX_MTN	2	22
33469	OX_MTN	3	22
33469	OX_MTN	4	22
33469	OX_MTN	5	22
33469	OX_MTN	6	22
33469	OX_MTN	7	22
36863	DVRaGT1	1	21
36864	DVRbGt2	1	21
36865	DVRaST3	1	21
36859	Laf300	2	20
36859	Laf300	1	20
36858	Gia100	1	20
36895	Gia200	1	20
35861	SJ-SCL W	1	20
35854	LECEFGT1	1	20
35855	LECEFGT2	1	20
35856	LECEFGT3	1	20
35857	LECEFGT4	1	20
35858	LECEFST1	1	20
35860	OLS-AGNE	1	20
33468	SRI INTL	1	16
35304	RUSELCT1	1	12
35305	RUSELCT2	2	12
35306	RUSELST1	3	12
36209	SLD ENRG	1	9
36221	DUKMOSS1	1	7
36222	DUKMOSS2	1	7
36223	DUKMOSS3	1	7
36224	DUKMOSS4	1	7
36225	DUKMOSS5	1	7
36226	DUKMOSS6	1	7
30532	0162-WD	FW	7

39233	GRNRDG	1	6
33107	DEC STG1	1	6
33108	DEC CTG1	1	6
33109	DEC CTG2	1	6
33110	DEC CTG3	1	6
33102	COLUMBIA	1	6
33111	LMECCT2	1	6
33112	LMECCT1	1	6
33113	LMECST1	1	6
33136	CCCSD	1	6
33141	SHELL 1	1	6
33142	SHELL 2	1	6
33143	SHELL 3	1	6
33151	FOSTER W	1	6
33151	FOSTER W	2	6
33151	FOSTER W	3	6
32901	OAKLND 1	1	6
32902	OAKLND 2	1	6
32903	OAKLND 3	1	6
38118	ALMDACT1	1	6
38119	ALMDACT2	1	6
32910	UNOCAL	1	6
32910	UNOCAL	2	6
32910	UNOCAL	3	6
32920	UNION CH	1	5
33139	STAUFER	1	5
32741	HILLSIDE_12	1	5
32921	ChevGen1	1	5
32922	ChevGen2	1	5
32923	ChevGen3	3	5
32900	CRCKTCOG	1	5
33188	MARSHCT1	1	3
33189	MARSHCT2	2	3
33190	MARSHCT3	3	3
33191	MARSHCT4	4	3
33118	GATEWAY1	1	3
33119	GATEWAY2	1	3
33120	GATEWAY3	1	3
30522	0354-WD	EW	3
33178	RVEC_GEN	1	3
35310	PPASSWND	1	3

Table – Herndon

Effectiveness factors to the Herndon-Manchester 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
34624	BALCH 1	1	22
34616	KINGSRIV	1	21
34648	DINUBA E	1	20
34671	KRCDPCT1	1	19
34672	KRCDPCT2	1	19
34308	KERCKHOF	1	18
34344	KERCK1-1	1	18
34345	KERCK1-3	3	18
34677	Q558	1	15
34690	CORCORAN_3	FW	15
34692	CORCORAN_4	FW	15
34696	CORCORANPV_S	1	15
34610	HAAS	1	13
34610	HAAS	2	13
34612	BLCH 2-2	1	13
34614	BLCH 2-3	1	13
34431	GWF_HEP1	1	8
34433	GWF_HEP2	1	8
34617	Q581	1	5
34680	KANSAS	1	5
34467	GIFFEN_DIST	1	4

34563	STROUD_DIST	2	4
34563	STROUD_DIST	1	4
34608	AGRICO	2	4
34608	AGRICO	3	4
34608	AGRICO	4	4
34644	Q679	1	4
365502	Q632BC1	1	4

Table – LA Basin

Effectiveness factors to the Mesa – Laguna Bell #1 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
29951	REFUSE	D1	35
24239	MALBRG1G	C1	34
24240	MALBRG1G	C2	34
24241	MALBRG1G	S3	34
29903	ELSEG6ST	6	27
29904	ELSEG5GT	5	27
29902	ELSEG7ST	7	27
29901	ELSEG8GT	8	27
24337	VENICE	1	26
24094	MOBGEN1	1	26
24329	MOBGEN2	1	26
24332	PALOGEN	D1	26
24011	ARCO 1G	1	23
24012	ARCO 2G	2	23

24013	ARCO 3G	3	23
24014	ARCO 4G	4	23
24163	ARCO 5G	5	23
24164	ARCO 6G	6	23
24062	HARBOR G	1	23
24062	HARBOR G	HP	23
25510	HARBORG4	LP	23
24327	THUMSGEN	1	23
24020	CARBGEN1	1	23
24328	CARBGEN2	1	23
24139	SERRFGEN	D1	23
24070	ICEGEN	1	22
24001	ALAMT1 G	l	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24005	ALAMT5 G	5	18
24161	ALAMT6 G	6	18
90000	ALMT-GT1	X1	18
90001	ALMT-GT2	X2	18
90002	ALMT-ST1	X3	18
29308	CTRPKGEN	1	18
29953	SIGGEN	D1	18
29309	BARPKGEN	1	13
29201	WALCRKG1	1	12

29202	WALCRKG2	1	12
29203	WALCRKG3	1	12
29204	WALCRKG4	1	12
29205	WALCRKG5	1	12
29011	BREAPWR2	C1	12
29011	BREAPWR2	C2	12
29011	BREAPWR2	C3	12
29011	BREAPWR2	C4	12
29011	BREAPWR2	S1	12
24325	ORCOGEN	l	12
24341	COYGEN	l	11
25192	WDT1406_G	l	11
25208	DowlingCTG	1	10
25211	CanyonGT 1	1	10
25212	CanyonGT 2	2	10
25213	CanyonGT 3	3	10
25214	CanyonGT 4	4	10
24216	VILLA PK	DG	9

Table – Rector

Effectiveness factors to the Rector-Vestal 230 kV line:

Gen Bus	Gen Name	Gen ID	MW Eff Factor (%)
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):

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
22982	TDM CTG2	1	25
22983	TDM CTG3	1	25

22981	TDM STG	1	25
22997	INTBCT	1	25
22996	INTBST	1	25
23440	DW GEN2 G1	1	25
23298	DW GEN1 G1	G1	25
23156	DU GEN1 G2	G2	25
23299	DW GEN1 G2	G2	25
23155	DU GEN1 G1	G1	25
23441	DW GEN2 G2	1	25
23442	DW GEN2 G3A	1	25
23443	DW GEN2 G3B	1	25
23314	OCO GEN G1	G1	23
23318	OCO GEN G2	G2	23
23100	ECO GEN1 G	G1	22
23352	ECO GEN2 G	1	21
22605	OTAYMGT1	1	18
22606	OTAYMGT2	1	18
22607	OTAYMST1	1	18
23162	PIO PICO CT1	1	18
23163	PIO PICO CT2	1	18
23164	PIO PICO CT3	1	18
22915	KUMEYAAY	1	17
23320	EC GEN2	1	17
22150	EC GEN1	1	17
22617	OY GEN	1	17

22604	OTAY	1	17
22604	OTAY	3	17
22172	DIVISION	1	17
22576	NOISLMTR	1	17
22704	SAMPSON	1	17
22092	CABRILLO	1	17
22074	LRKSPBD1	1	17
22075	LRKSPBD2	1	17
22660	POINTLMA	1	17
22660	POINTLMA	2	17
22149	CALPK_BD	1	17
22448	MESAHGTS	1	16
22120	CARLTNHS	1	16
22120	CARLTNHS	2	16
22496	MISSION	1	16
22486	MEF MR1	1	16
22124	CHCARITA	1	16
22487	MEF MR2	1	16
22625	LkHodG1	1	16
22626	LkHodG2	2	16
22332	GOALLINE	1	15
22262	PEN_CT1	1	15
22153	CALPK_ES	1	15
22786	EA GEN1 U6	1	15
22787	EA GEN1 U7	1	15

22783	EA GEN1 U8	1	15
22784	EA GEN1 U9	1	15
22789	EA GEN1 U10	1	15
22257	ES GEN	1	15
22263	PEN_CT2	1	15
22265	PEN_ST	1	15
22724	SANMRCOS	1	15
22628	PA GEN1	1	14
22629	PA GEN2	1	14
22082	BR GEN1	1	14
22112	CAPSTRNO	1	12

2025 LOCAL CAPACITY TECHNICAL STUDY

FINAL REPORT

AND STUDY RESULTS

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Executive Summary

This Report documents the results and recommendations of the 2025 Long-Term Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2021 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2019. On balance, the assumptions, processes, and criteria used for the 2025 Long-Term LCT Study mirror those used in the 2007-2020 LCT Studies.

During 2019 the CAISO conducted a stakeholder process to update the LCR criteria to the current mandatory standards (NERC, WECC and CAISO) from its previous version that pre-dated any form of NERC mandatory standards.[1] CAISO held open stakeholder meetings on May 30, July 18 and September 10, 2019 resulting in overwhelming support for aligning the LCR criteria with the mandatory standards. The CAISO Board approved the alignment at its general session on November 13-14, 2019.[2] Tariff changes to implement the alignment were approved by FERC on January 17, 2020, with no opposition from any market participant.[3]

The load forecast used in this study is based on the final adopted California Energy Demand 2020-2030 Revised Forecast, developed by the CEC; namely the load-serving entity (LSE) and balancing authority (BA) mid baseline demand with low additional achievable energy efficiency and photo voltaic (AAEE-AAPV), posted on 3/4/2020: https://efiling.energy.ca.gov/GetDocument.aspx?tn=232305&DocumentContentId=64305.

To aide procurement, this LCT study provides load profiles and transmission capacity information that shows the effectiveness of local resources in meeting temporal local reliability needs.

Overall, the capacity needed for LCR has increased by about 153 MW or about 0.7% from 2024 to 2025.

The LCR needs have decreased in the following areas: Stockton due to new transmission projects and changes to the LCR criteria, Big Creek/Ventura and San Diego due to load forecast decrease and new transmission projects, Humboldt requirement is the same.

The LCR needs have increased in the following areas: North Coast/North Bay and Fresno due to change in the LCR criteria, Bay Area, Sierra and Kern due to load forecast increase and changes to the LCR criteria, LA Basin due to CEC and SCE reallocation of substation loads resulting in a higher amount in Western LA Basin.

The narrative for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between the 2024 and 2025 LCT study results.

1 See stakeholder webpage: http://www.caiso.com/StakeholderProcesses/Local-capacity-technical-study-criteria-update Stakeholder comments as well as CAISO responses are also linked on the webpage.

2 See: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=A45DA998-F13E-4856-861D-0277E98D8E6E

3 Available at: http://www.caiso.com/Documents/Jan17-2020-LetterOrderAcceptingTariffRevisions-UpdateLocalCapacityTechnicalStudyCriteria-ER20-548.pdf

The 2024 and 2025 total LCR needs are provided below for comparison:

2025 Local Capacity Needs

	Qualifying Capacity				Capacity Available at Peak	2025 LCR Need Category C
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	191	0	**191**	**191**	**132**
North Coast/ North Bay	119	723	0	**842**	**842**	**837**
Sierra	1183	920	5	**2108**	**2103**	**1367***
Stockton	116	491	12	**619**	**607**	**619***
Greater Bay	604	6732	8	**7344**	**7344**	**6110***
Greater Fresno	216	2815	361	**3392**	**3191**	**1971***
Kern	5	330	78	**413**	**335**	**186***
Big Creek/ Ventura	424	2963	250	**3637**	**3637**	**1002**
LA Basin	1197	6215	11	**7423**	**7423**	**6309**
San Diego/ Imperial Valley	2	4438	378	**4818**	**4440**	**3557**
Total	**3866**	**25818**	**1103**	**30787**	**30113**	**22090**

2024 Local Capacity Needs

	Qualifying Capacity				Capacity Available at Peak	2024 LCR Need Category B	2024 LCR Need Category C
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed	Capacity Needed
Humboldt	0	197	0	**197**	**197**	83	**132**
North Coast/ North Bay	117	715	1	**833**	**832**	706	**706**
Sierra	1168	986	6	**2160**	**2154**	788	**1304**
Stockton	137	680	1	**699**	**698**	388*	**675***
Greater Bay	617	7011	12	**7640**	**7640**	3494	**4395**
Greater Fresno	203	2733	393	**3329**	**2901**	1711	**1711***
Kern	8	354	103	**465**	**362**	0	**152***
Big Creek/ Ventura	402	2774	305	**3481**	**3481**	2083*	**2577***
LA Basin	1344	7038	17	**8399**	**8399**	6224	**6260**
San Diego/ Imperial Valley	4	4032	523	**4559**	**4036**	4025	**4025**
Total	**4000**	**26520**	**1361**	**31762**	**30700**	**19502**	**21937**

* Details about magnitude of deficiencies can be found in the applicable section below. 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.

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1 Overview of the Study: Inputs, Outputs and Options

1.1 Objectives

The intent of the 2025 Long-Term 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, as was the objective of all previous Local Capacity Technical Studies.

To aide procurement, this LCT study provides load profiles and transmission capacity information that shows the effectiveness of local resources in meeting temporal local reliability needs.

1.2 Key Study Assumptions

1.2.1 Inputs, Assumptions and Methodology

The inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2021 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2019. They are similar to those used and incorporated in previous LCT studies. The following table sets forth a summary of the approved inputs and methodology that have been used in this 2025 Long-Term LCT Study:

Table 1.2-1 Summary Table of Inputs and Methodology Used in this LCT Study:

Issue	How 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 LCT Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
All Performance Levels, including incorporation of PTO operational solutions	This LCT Study is being published based on the most stringent of all mandatory reliability standards. 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 mandatory standards 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 2025 Long-Term LCT Study methodology and assumptions are provided in Section III, below.

1.3 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.[4] 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.

1.4 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 (N-0) the CAISO must protect for all single contingencies (N-1) and common mode (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 temporal differentiation between two existing NERC Category P6 and P7 events. N-1-1 represents NERC Category C6 ("category P1 contingency, manual system adjustment, followed by another category P1 contingency"). The N-2 represents NERC Category P7 ("any two circuits of a multiple circuit tower line") as well as WECC-S2 (for 500 kV only) ("any two circuits in the same right-of-way") with no manual system adjustment between the two contingencies.

[4] Pub. Utilities Code § 345

1.5 Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCR Report is based on the most stringent mandatory standard (NERC, WECC or CAISO). The CAISO tests the electric system in regards to thermal overloads as well as dynamic and reactive margin compliance with the existing standards.

1.5.1 Performance Criteria

Category P0, P1 & P3 system performance requires that 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.

The NERC Planning 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.[5] All Category P2, P4, P5, P6, P7 and extreme event 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 planning criteria.

Generally, Category P2, P4, P5, P6, P7 and extreme event 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 P1, the event is effectively a Category P6 or N-1-1 scenario. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of

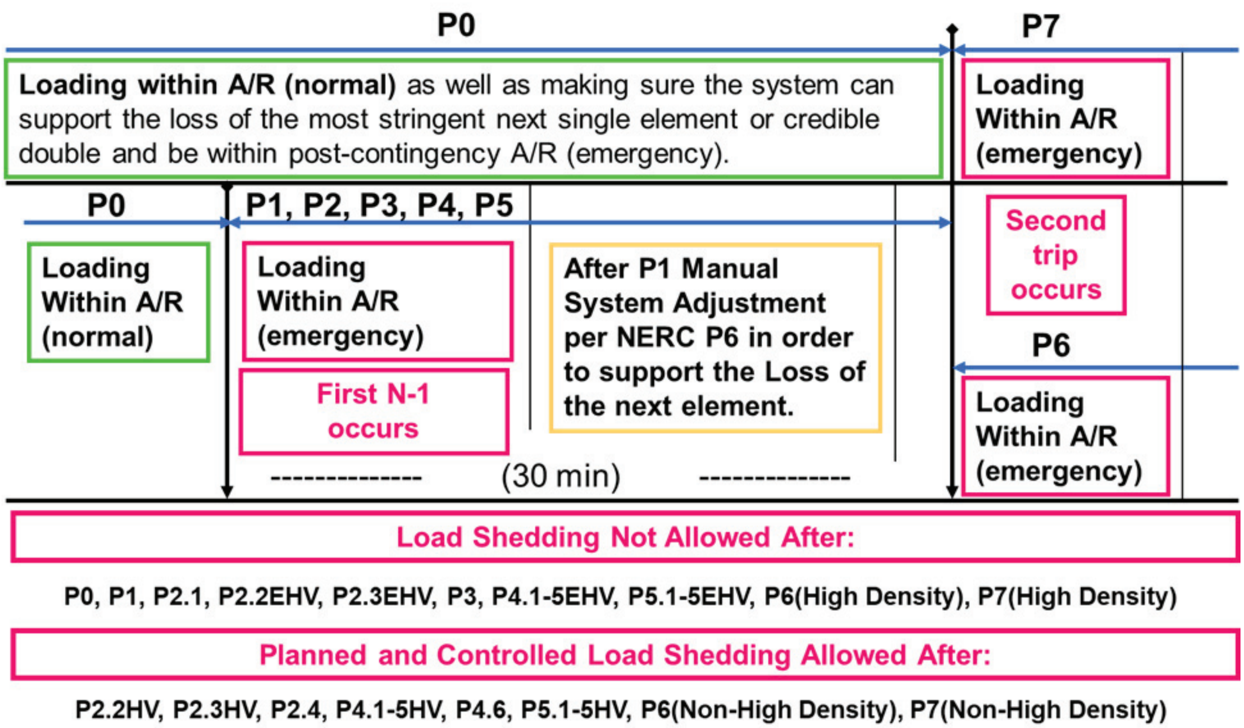
[5] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit 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 sometimes these systems will operate when not required and other times they will not operate when needed.

supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

1.5.2 CAISO Statutory Obligation Regarding Safe Operation

The ISO must 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 (8760 hours per year), the ISO must protect for all single contingencies (P1, P2) and multiple contingencies (P4, P5) as well as common mode double line outages (P7). As a further example, after a single contingency, the ISO must readjust the system in order to be able to support the loss of the next most stringent contingency (P3 , P6 and P1+P7 resulting in potential voltage collapse or dynamic instability).

Figure 1.5-1 Temporal graph of LCR Category P0-P7



The following definitions guide the CAISO's interpretation of the Reliability Criteria 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, the 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, and 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 agreed 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 Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

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 ISO Grid Planning standards (ISO SPS3)

b. Increase generation – this generation will become part of the LCR need

Actions, which shall not be taken as system readjustment after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

1. Load drop – based on the intent of the ISO/WECC and NERC criteria for category P1 contingencies.

An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. NERC and ISO Planning standards mandate that no load shedding should be done immediately after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency. The system should be planned with no load shedding regardless of when it may occur (immediately or within 15-30 minutes after the first contingency). It follows that load shedding may not be utilized as part of the system readjustment period – in order to protect for the next most limiting contingency. Therefore, if there are available resources in the local area, such resources should be used during the manual adjustment period (and included in the LCR need) before resorting to shedding firm load.

Firm load shedding is allowed in a planned and controlled manner after the first contingency in P2.2(HV), P2.3(HV), P2.4, P4.1-5(HV), P4.6, P5.1-5(HV) and after the second contingency in P6(non-high density area), P7(non-high density area) & P1 system adjusted followed by P7 category events.

This interpretation tends to guarantee that firm load shedding is used to address Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) conditions only under the limited circumstances where no other resource or validated operational measure is available. A contrary interpretation would constitute a departure from existing practice and degrade current service expectations by increasing load's exposure to service interruptions.

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.

2 Assumption Details: How the Study was Conducted

2.1 System Planning Criteria

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

Table 2.1-1: Criteria Comparison for Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	New Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X[1]
2. Transmission Circuit (L-1)	X	X[1]	X[1]
3. Transformer (T-1)	X	X[1,2]	X[1]
4. Shunt Device	X		X[1]
5. Single Pole (dc) Line	X	X[1]	X[1]
P2 – Single contingency			
1. Opening a line section w/o a fault	X		X
2. Bus Section fault	X		X
3. Internal Breaker fault (non-Bus-tie Breaker)	X		X
4. Internal Breaker fault (Bus-tie Breaker)	X		X
P3 – Multiple Contingency – G-1 + system adjustment and:			
1. Generator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Transformer (T-1)	X	X[2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X	X
P4 – Multiple Contingency - Fault plus stuck breaker			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X
6. Bus-tie breaker	X		X
P5 – Multiple Contingency – Relay failure (delayed clearing)			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X

P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:			
1. Transmission Circuit (L-1)	X	x	X
2. Transformer (T-1)	X	x	X
3. Shunt Device	X		X
4. Bus section	X		X
P7 – Multiple Contingency - Fault plus stuck breaker			
1. Two circuits on common structure (L-2)	X	X	X
2. Bipolar DC line	X	X	X
Extreme event – loss of two or more elements			
Two generators (Common Mode) G-2	X[4]	X	X[4]
Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2	X[4]	X[3]	X[5]
All other extreme combinations.	X[4]		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.

5 Expanded to include any P1 system readjustment followed by any P7 without stuck breaker. For voltage collapse or dynamic instability situations mitigation is required "if there is a risk of cascading" beyond a relatively small predetermined area – less than 250 MW - directly affected by the outage.

Table 2.1-2: Criteria Comparison for non-Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	New Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X
2. Transmission Circuit (L-1)	X	X[1]	X
3. Transformer (T-1)	X	X[1,2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X[1]	X
P2 – Single contingency			
1. Opening a line section w/o a fault			
2. Bus Section fault			
3. Internal Breaker fault (non-Bus-tie Breaker)			
4. Internal Breaker fault (Bus-tie Breaker)			

P3 – Multiple Contingency – G-1 + system adjustment and:			
1. Generator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Transformer (T-1)	X	X[2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X	X
P4 – Multiple Contingency - Fault plus stuck breaker			
1. Generator (G-1)			
2. Transmission Circuit (L-1)			
3. Transformer (T-1)			
4. Shunt Device			
5. Bus section			
6. Bus-tie breaker			
P5 – Multiple Contingency – Relay failure (delayed clearing)			
1. Generator (G-1)			
2. Transmission Circuit (L-1)			
3. Transformer (T-1)			
4. Shunt Device			
5. Bus section			
P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:			
1. Transmission Circuit (L-1)		x	
2. Transformer (T-1)		x	
3. Shunt Device			
4. Bus section			
P7 – Multiple Contingency - Fault plus stuck breaker			
1. Two circuits on common structure (L-2)		X	
2. Bipolar DC line		X	
Extreme event – loss of two or more elements			
Two generators (Common Mode) G-2		X	
Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2		X[3]	
All other extreme combinations.			

[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.

A significant number of simulations were run to determine the most critical contingencies within each local area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all tested contingencies were measured against the system performance requirements defined by the criteria shown in Tables 1 and 2. Where the specific system performance requirements were not met, generation was adjusted until performance requirements were met for the local area. The adjusted generation constitutes the minimum generation needed in the local area. The following describes how the criteria were tested for the specific type of analysis performed.

2.1.1 Power Flow Assessment:

Table 2.1-3 Power flow criteria

Contingencies	Thermal Criteria[1]	Voltage Criteria[2]
P0	Applicable Rating	Applicable Rating
P1 [3]	Applicable Rating	Applicable Rating
P2	Applicable Rating	Applicable Rating
P3	Applicable Rating	Applicable Rating
P4	Applicable Rating	Applicable Rating
P5	Applicable Rating	Applicable Rating
P6 [4]	Applicable Rating	Applicable Rating
P7	Applicable Rating	Applicable Rating
P1 + P7 [4]	-	No Voltage Collapse

1 Applicable Rating – Based on CAISO Transmission Register or facility upgrade plans including established Path ratings.

2 Applicable Rating – CAISO Grid Planning Criteria or facility owner criteria as appropriate.

3 Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions and be able to safely prepare for the loss of the next most stringent element and be within Applicable Rating after the loss of the second element.

4 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.

2.1.2 Post Transient Load Flow Assessment:

Table 2.1-4 Post transient load flow criteria

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.

2.1.3 Stability Assessment:

Table 2.1-5 Stability criteria

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 – CAISO Grid Planning Criteria or facility owner criteria as appropriate.

2.2 Load Forecast

2.2.1 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.

2.2.2 Base Case Load Development Method

The method used to develop the load 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.

2.2.2.1 *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.

a. 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 the division.

b. Allocation of division load to transmission bus level

Since the loads in the base case 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 base case loads 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.

2.2.2.2 *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.

[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.

2.3 Power Flow Program Used in the LCR analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 21.0_07 and PowerGem's Transmission Adequacy and Reliability Assessment (TARA) program version 1902. 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. A 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.

2.4 Estimate of Battery Storage Needs due to Charging Constraints

Local areas and sub-areas have limited transmission capability and therefore rely on internal resources to be available in order to reliably serve internal load. Battery storage will help serve local load during the discharge cycle, however it will also increase local load during the charging cycle.

Due to recent procurement activities geared toward the acquisition of this type of technology, the CAISO is herein estimating the characteristics (MW, MWh, discharge duration) required from battery storage technology in order to seamlessly integrate in each local area and sub-area.

The CAISO expects that for batteries that displace other local resource adequacy resources, the transmission capability under the most limiting contingency and the other local capacity resources must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period.

For each local area and sub-area, the CAISO has estimated the battery storage characteristics, given their unique load shape, constraints and requirements as well as the energy characteristics of other resources required to meet standards. Due to this fact, the strict addition of the sub-area battery storage characteristics (MW, MWh and duration) may not closely align with the overall local area battery storage characteristic requirements (MW, MWh and duration).

Assumptions

1) Total load serving capability includes capability from transmission system and local generation needed for LCR under the worst contingency.

2) Storage added replaces existing generation MW for MW. First the batteries will replace as much as possible of existing gas resources, Second if the area and/or sub-area has run out of gas resources to displace then other technologies may be reduced in order to determine the maximum battery charging limit.
3) Effectiveness factors are assumed not to be a factor. Battery storage is assumed to be installed at the same sites where resources are displaced or assumed to have the same effectiveness factors.
4) Deliverability of incremental storage capacity is not evaluated. It is assumed battery storage will take over deliverability from old resources through repower. Any new battery storage resource needs to go through the generation interconnection process in order to receive deliverability and it is not evaluated in this study. CAISO cannot guaranty that there is enough deliverability available for new resources. New transmission upgrades may be required in order to make such new resources deliverable to the aggregate of load.
5) Includes battery storage charging/discharging efficiency of 85%.
6) Daily charging required is distributed to all non-discharging hours proportionally using delta between net load and the total load serving capability.
7) Energy required for charging, beyond the transmission capability under contingency condition, is produced by other LCR required resources within the local area and sub-area that are available for production during off-peak hours.
8) Hydro resources are considered to be available for production during off-peak hours, however these resources are energy limited themselves and based on past availability data they can have severely limited output during off-peak hours especially during late summer peaks under either normal or dry hydro years.
9) The study assumes the ability to provide perfect dispatch and the ability to enforce charging requirements for multiple contingency conditions (like N-1-1) in the day ahead time frame while the system is under normal (no contingency) conditions. CAISO software improvements and/or augmentations are required in order to achieve this goal.

Installing battery storage with insufficient characteristics (MW, MWh and duration) will not result in a one for one reduction of the local area or sub-area need for other types of resources. The CAISO expects that the overall RA portfolio provided by all LSEs to account for the uplift, beyond the minimum LCR need, in MWs required from other type of resources for all areas and sub-areas where LSEs have procured battery storage beyond the charging capability or with incorrect characteristics (MW, MWh and duration). If uplift is not provided the CAISO may use its back stop authority to assure that reliability standards are met throughout the day, including off-peak hours.

3 Locational Capacity Requirement Study Results

3.1 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 3.1-1 2025 Local Capacity Needs vs. Peak Load and Local Area Resources

	2025 Total LCR (MW)	Peak Load (1 in10) (MW)	2025 LCR as % of Peak Load	Total NQC Local Area Resources (MW)	2025 LCR as % of Total NQC
Humboldt	132	153	86%	191	69%
North Coast/North Bay	837	1481	57%	842	99%
Sierra	1367	1918	71%	2108	65%
Stockton	619	950	65%	619	100%
Greater Bay	6110	10743	57%	7344	83%
Greater Fresno	1971	3279	60%	3392	58%
Kern	186	1651	11%	413	45%
Big Creek/Ventura	1002	4429	23%	3637	28%
LA Basin	6309	18826	34%	7423	85%
San Diego/Imperial Valley	3557	4675	76%	4818	74%
Total*	**22090**	**48105**	**46%**	**30787**	**72%**

Table 3.1-2 2024 Local Capacity Needs vs. Peak Load and Local Area Resources

	2024 Total LCR (MW)	Peak Load (1 in10) (MW)	2024 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2024 LCR as % of Total Area Resources
Humboldt	132	153	86%	197	67%
North Coast/North Bay	706	1537	46%	833	85%
Sierra	1304	1864	70%	2160	60%
Stockton	675	1329	51%	699	97%
Greater Bay	4395	10427	42%	7640	58%
Greater Fresno	1711	3336	51%	3329	51%
Kern	152	903	17%	465	33%
LA Basin	2577	4958	52%	3481	74%
Big Creek/Ventura	6260	19295	32%	8399	75%
San Diego/Imperial Valley	4025	4805	84%	4559	88%
Total*	**21937**	**48607**	**45%**	**31762**	**69%**

* Value shown only illustrative, since each local area peaks at a different time.

Table 3.1-1 and Table 3.1-2 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 "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. Units scheduled to become operational before June 1 of 2025 have been included in this 2025 Long-Term LCT Study Report and added to the total NQC values for those respective areas (see detail write-up for each area).

Regarding the main tables up front (page 2), the first column, "August Qualifying Capacity," reflects three 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, municipal and QFs). The second set is "market" based resources (market, net seller, wind and battery). The third set are solar resources, since they may or may not be available during the actual peak hour for the respective local area. The second column, "Capacity at Peak" identifies how much of the August Qualifying Capacity is expected to be available during the peak time for each particular local area. The third column, "YEAR LCR Need", sets forth the local capacity requirements, without the deficiencies that must be addressed, necessary to attain a service reliability level required to comply with NERC/WECC/CAISO mandatory reliability standards.

Table 3.1-3 includes estimated characteristics (MW, MWh, discharge duration) required from battery storage technology in order to seamlessly integrate in each local area and sub-area. The CAISO expects that for batteries that displace other local resource adequacy resources, the transmission capability under the most limiting contingency and the other local capacity resources must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period.

Table 3.1-3 2025 Battery Storage Characteristics Limited by Charging Capability

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	Replacing mostly	Comment
Humboldt	48	240	9	gas	
North Coast/North Bay Overall	225	2025	10	geothermal	
Eagle Rock	30	120	5	geothermal	
Fulton	110	1100	11	geothermal	
Sierra	-	-	-	-	Flow through
Placer	60	480	9	hydro	

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	Replacing mostly	Comment
Pease	-	-	-	-	Need eliminated
Gold Hill-Drum	0	0	0	-	
Stockton	-	-	-	-	Sum of sub-areas
Lockeford	-	-	-	-	Need eliminated
Tesla-Bellota	0	0	0	-	
Greater Bay Overall	1850	18500	11	gas	
Llagas	110	770	7	gas	
San Jose	325	2600	16	gas	
South Bay-Moss Landing	400	4400	13	gas	
Oakland	20	180	16	distillate	
Greater Fresno Overall	1300	10400	9	hydro	
Panoche	100	1000	11	gas	
Herndon	390	3120	9	hydro	
Borden	25	150	4	hydro	
Hanford	0	0	0	-	
Coalinga	0	0	0	-	
Reedley	0	0	0	-	
Kern Overall	-	-	-	-	N/A
Westpark	40	360	10	gas	
Kern 70 kV	0	0	0	-	
Kern Oil	69	552	9	gas	
South Kern PP	150	1350	10	gas	
Big Creek/Ventura Overall[7]	-	-	-	gas	
Santa Clara	130	960	12	gas	
LA Basin Overall	4500	45000	11	gas	
Eastern	1800	18000	11	gas	LA Basin split
Western	2700	27000	11	gas	LA Basin split
El Nido	250	2000	9	gas	
San Diego/Imperial Valley Overall	920	8280	10	gas	
San Diego	920	8280	10	gas	
El Cajon	49	441	10	gas	
Border	156	780	7	gas	

[7] The energy storage analysis performed for Big Creek–Venura area and its sub-areas is based on energy storage replacing gas fired local capacity. Further studies will be performed, if needed, to determine the amount of storage that can be added to replace the hydro, solar and demand response local capacity available in the area.

3.2 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.

3.2.1 Humboldt Area

3.2.1.1 *Area Definition*

The transmission tie lines into the area include:

Bridgeville-Cottonwood 115 kV line #1

Humboldt-Trinity 115 kV line #1

Laytonville-Garberville 60 kV line #1

Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

Bridgeville is in, Low Gap, Wildwood and Cottonwood are out

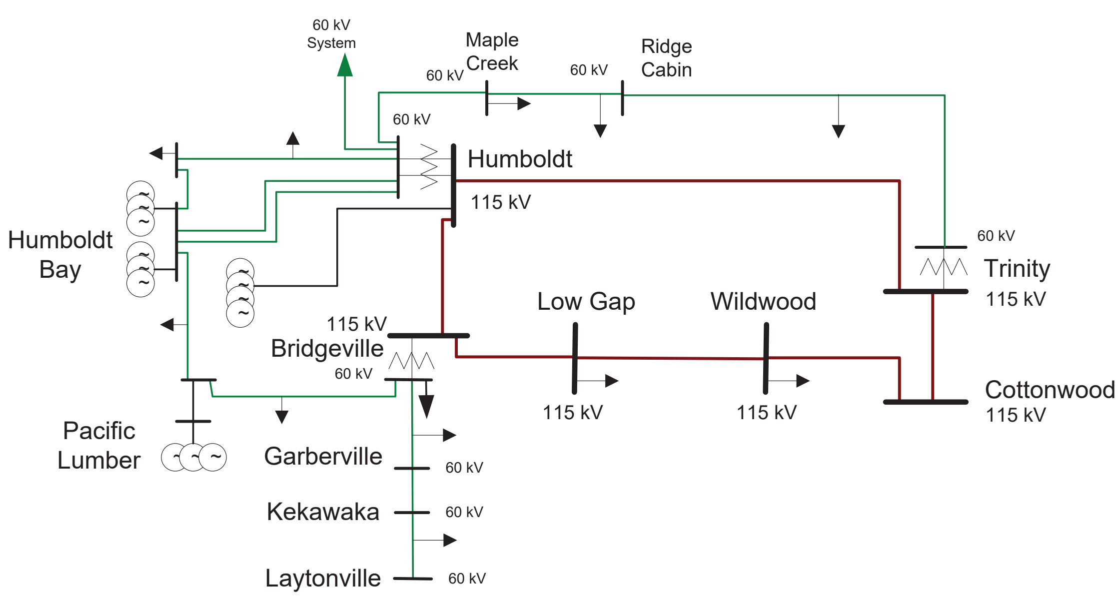
Humboldt is in, Trinity is out

Kekawaka and Garberville are in, Laytonville is out

Maple Creek is in, Trinity and Ridge Cabin are out

3.2.1.1.1 Humboldt LCR Area Diagram

Figure 3.2-1 Humboldt LCR Area



3.2.1.1.2 Humboldt LCR Area Load and Resources

Table 3.2-1 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 18:40 PM.

This area does not contain models of solar resources capable of providing resource adequacy.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-1 Humboldt LCR Area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	151	Market	191	191
AAEE	-8	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**143**	LTPP Preferred Resources	0	0
Transmission Losses	10	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**153**	**Total**	**191**	**191**

3.2.1.1.3 Humboldt LCR Area Hourly Profiles

Figure 3.2-2 illustrates the forecast 2025 profile for the summer peak, winter peak and spring off-peak days for the Humboldt LCR area with the Category P6 transmission capability without resources. Figure 3.2-3 illustrates the forecast 2025 hourly profile for Humboldt LCR area with the Category P6 transmission capability without resources.

Figure 3.2-2 Humboldt 2025 Peak Day Forecast Profiles

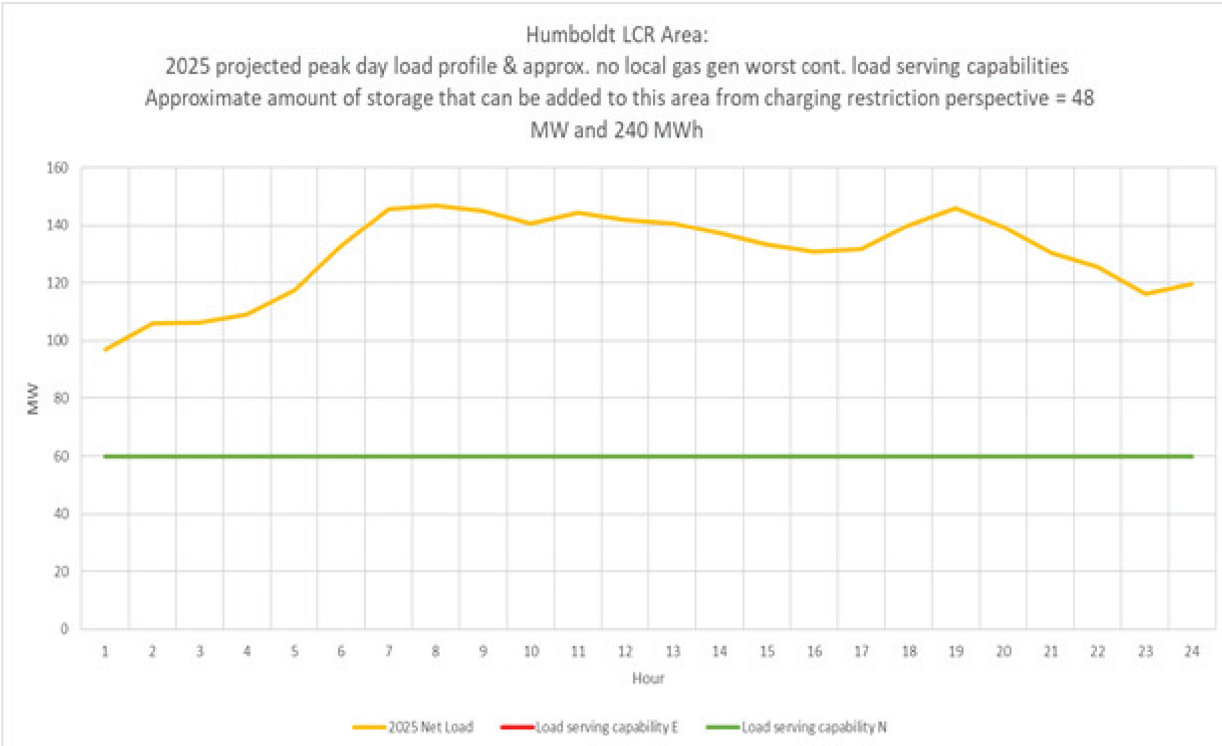
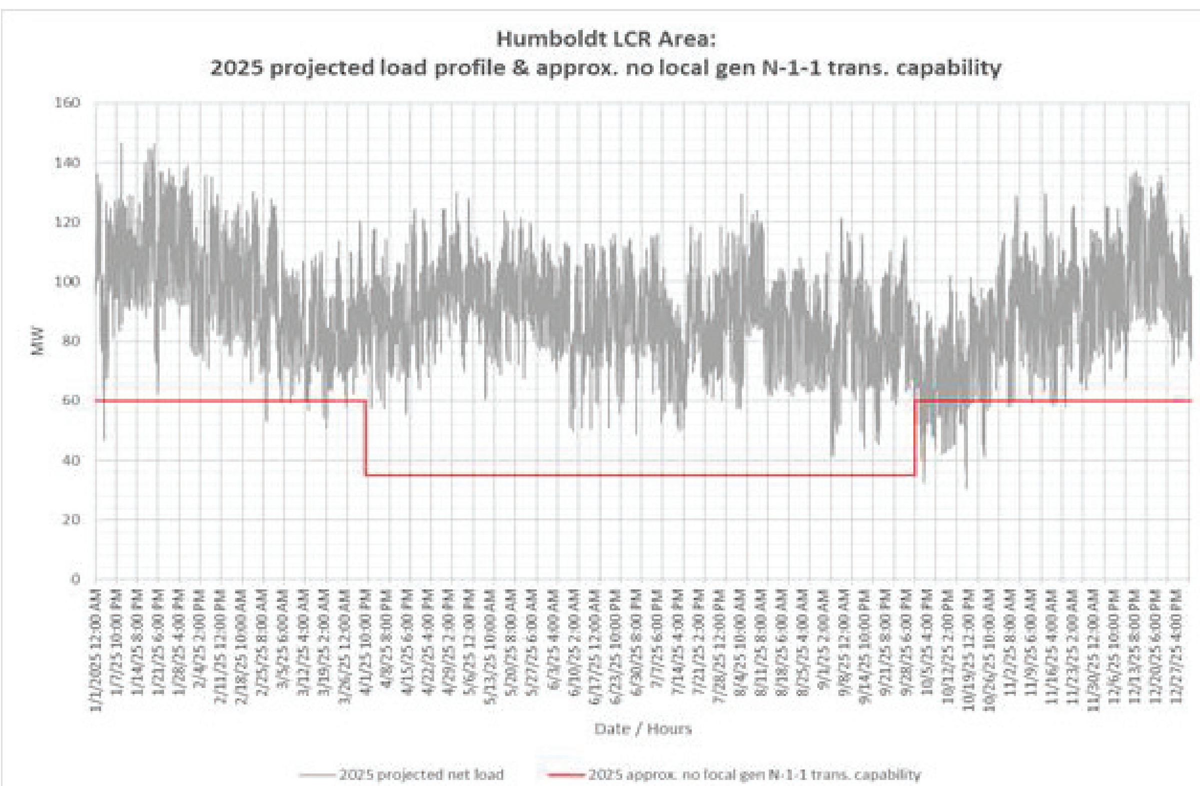


Figure 3.2-3 Humboldt 2025 Forecast Hourly Profile



3.2.1.1.4 Approved transmission projects included in base cases

None

3.2.1.2 *Humboldt Overall LCR Requirement*

Table 3.2-2 identifies the area LCR requirements. The LCR requirement for Category P6 contingency is 132 MW.

Table 3.2-2 Humboldt LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115 kV & Humboldt - Humboldt Bay 115 kV	132

3.2.1.2.1 Effectiveness factors

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

3.2.1.2.2 Changes compared to last year's results

Compared with 2024 the load forecast is the same and so is the LCR need.

3.2.2 North Coast / North Bay Area

3.2.2.1 *Area Definition*

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

Cortina-Mendocino 115 kV Line

Cortina-Eagle Rock 115 kV Line

Willits-Garberville 60 kV line #1

Vaca Dixon-Lakeville 230 kV line #1

Tulucay-Vaca Dixon 230 kV line #1

Lakeville-Sobrante 230 kV line #1

Ignacio-Sobrante 230 kV line #1

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

Cortina is out, Mendocino and Indian Valley are in

Cortina is out, Eagle Rock, Highlands and Homestake are in

Willits and Lytonville are in, Kekawaka and Garberville are out

Vaca Dixon is out, Lakeville is in

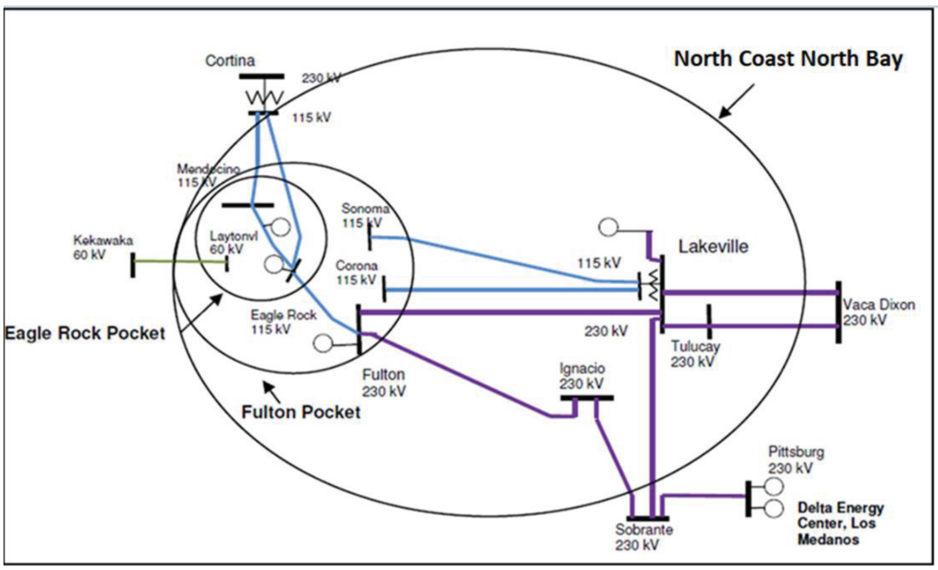
Tulucay is in, Vaca Dixon is out

Lakeville is in, Sobrante is out

Ignacio is in, Sobrante and Crocket are out

3.2.2.1.1 North Coast and North Bay LCR Area Diagram

Figure 3.2-4 North Coast and North Bay LCR Area



3.2.2.1.2 North Coast and North Bay LCR Area Load and Resources

Table 3.2-3 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 18:20 PM.

This area does not contain models of solar resources capable of providing resource adequacy.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-3 North Coast and North Bay LCR Area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1458	Market, Net Seller	723	723
AAEE	-16	MUNI	114	114
Behind the meter DG	0	QF	5	5

Net Load	**1442**	Solar	0	0
Transmission Losses	39	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1481**	**Total**	**842**	**842**

3.2.2.1.3 North Coast and North Bay LCR Area Hourly Profiles

Figure 3.2-5 illustrates the forecast 2025 profile for the peak day for the North Coast North Bay LCR sub-area with the Category P2-4 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-6 illustrates the forecast 2025 hourly profile for North Coast North Bay LCR sub-area with the Category P2-4 emergency load serving capability without local gas resources.

Figure 3.2-5 North Coast and North Bay 2025 Peak Day Forecast Profiles

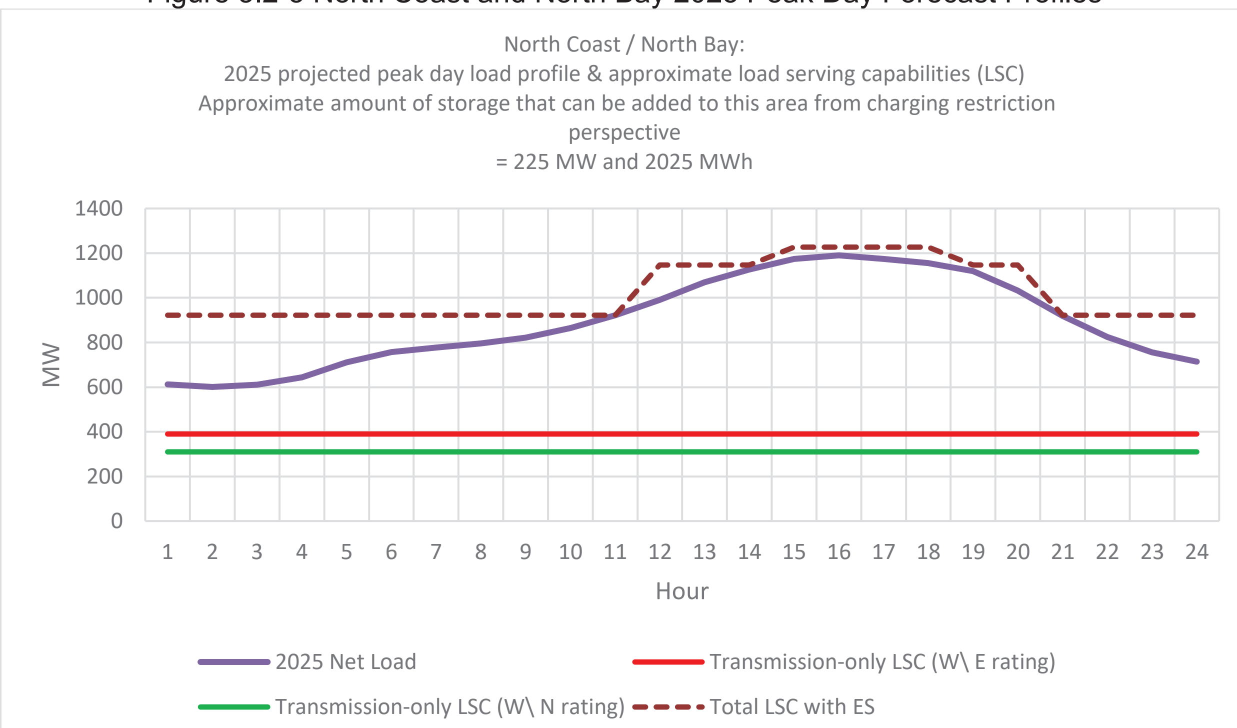
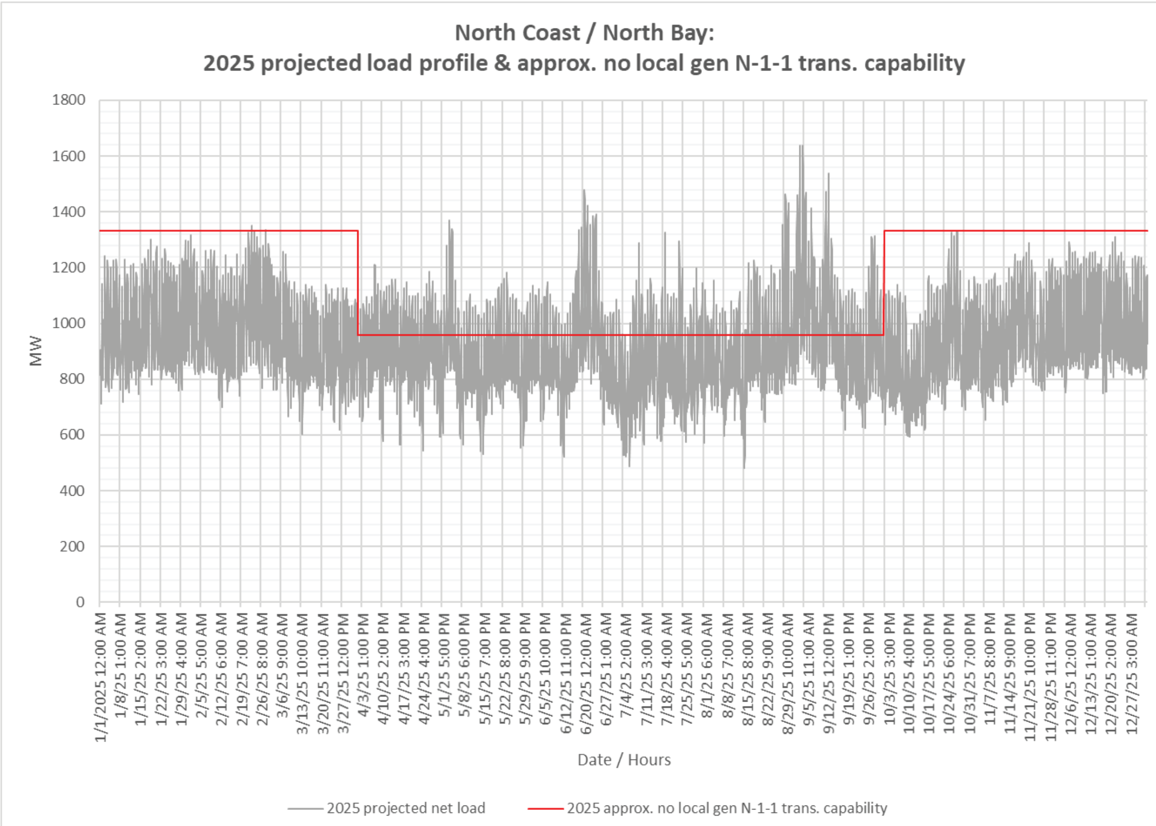


Figure 3.2-6 North Coast and North Bay 2025Forecast Hourly Profile



3.2.2.1.4 Approved transmission projects modeled in base cases

Lakeville 60 kV Area Reinforcement

Clear Lake 60 kV System Reinforcement

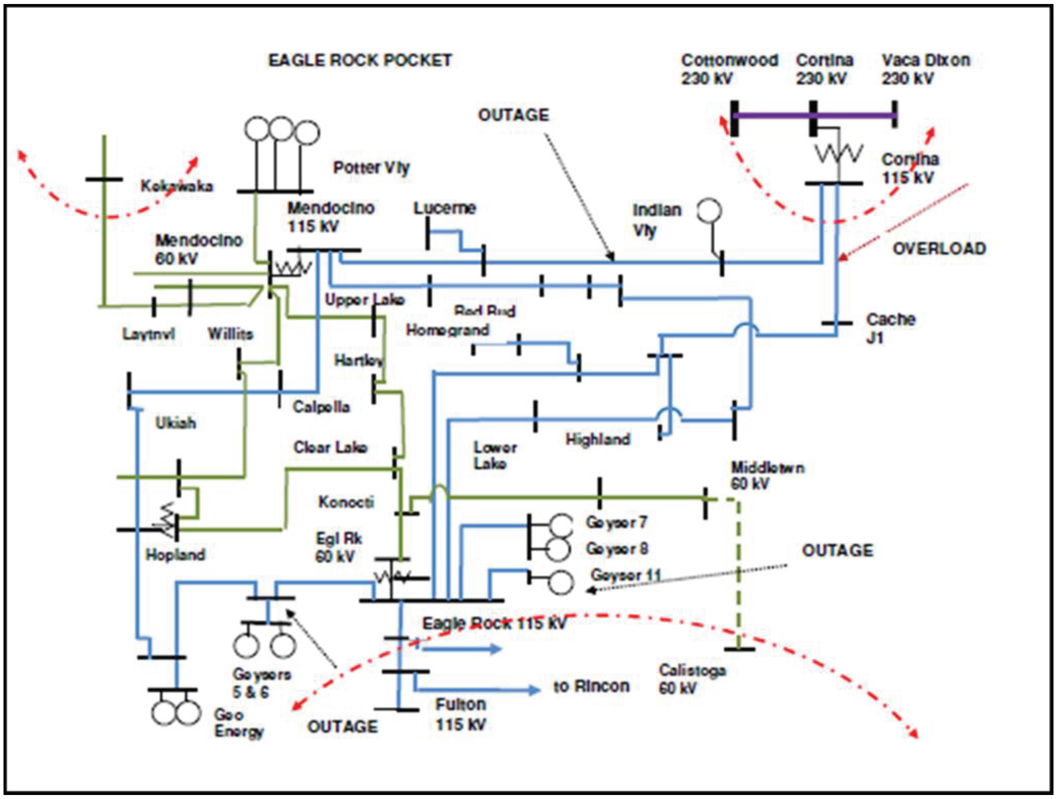
Ignacio Area Upgrade

3.2.2.2 *Eagle Rock LCR Sub-area*

Eagle Rock is a Sub-area of the North Coast and North Bay LCR Area.

3.2.2.2.1 Eagle Rock LCR Sub-area Diagram

Figure 3.2-7 Eagle Rock LCR Sub-area



3.2.2.2.2 Eagle Rock LCR sub-area Load and Resources

Table 3.2-4 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-4 Eagle Rock LCR Area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	226	Market, Net Seller	248	248
AAEE	-2	MUNI	2	2
Behind the meter DG	0	QF	0	0
Net Load	**224**	Solar	0	0
Transmission Losses	11	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**235**	**Total**	**250**	**250**

3.2.2.2.3 Eagle Rock LCR Sub-area Hourly Profiles

Figure 3.2-8 illustrates the forecast 2025 profile for the peak day for the Eagle Rock LCR Sub-area with the Category P3 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-9 illustrates the forecast 2025 hourly profile for North Coast North Bay LCR Sub-area with the Category P3 emergency load serving capability without local gas resources.

Figure 3.2-8 Eagle Rock LCR Sub-area 2025 Peak Day Forecast Profiles

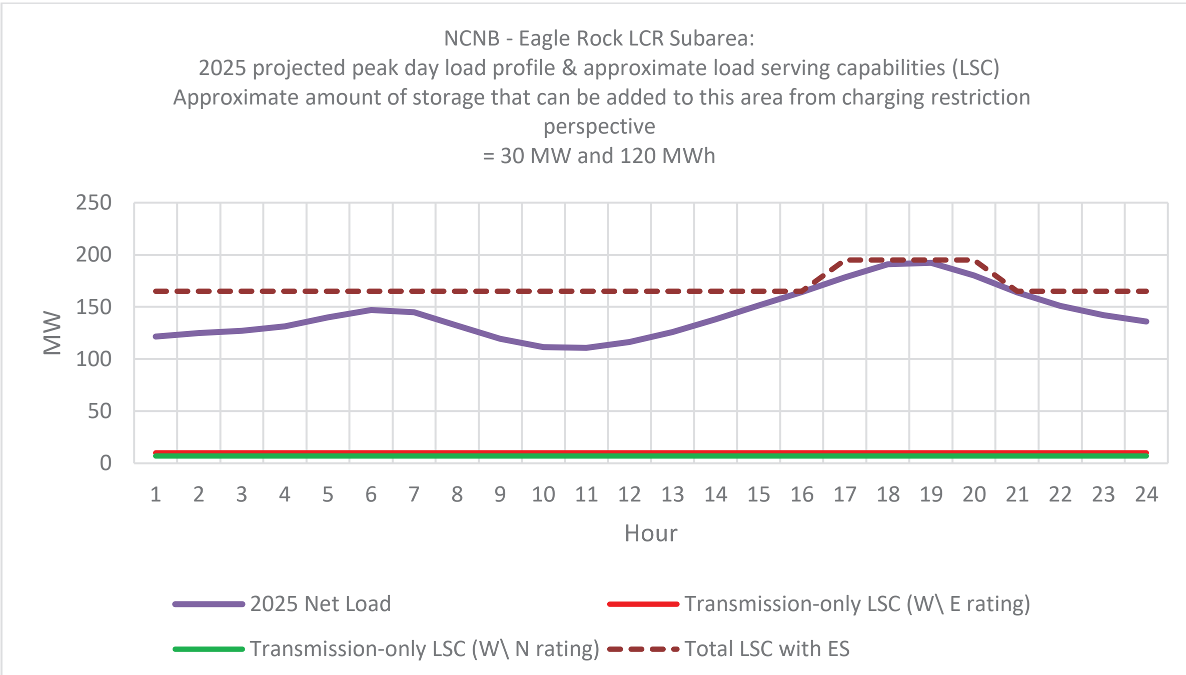
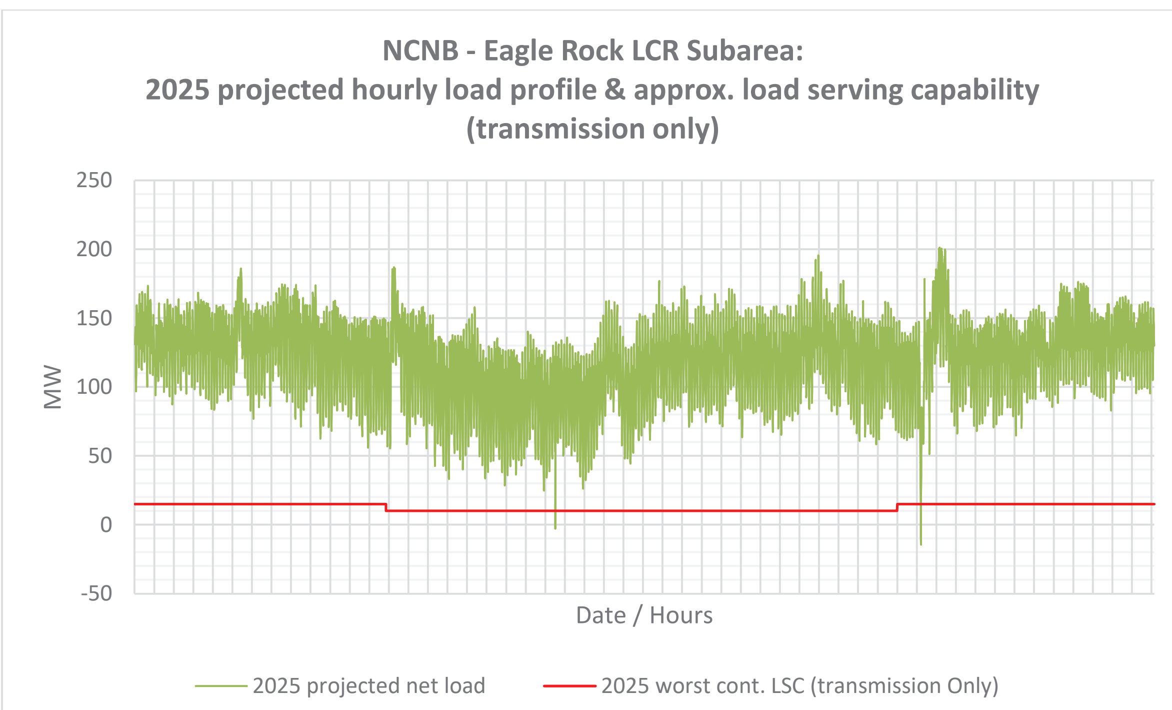


Figure 3.2-9 Eagle Rock LCR Sub-area 2025 Forecast Hourly Profiles



3.2.2.2.4 Eagle Rock LCR Sub-area Requirement

Table 3.2-5 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 184 MW.

Table 3.2-5 Eagle Rock LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P3	Eagle Rock-Cortina 115 kV line	Cortina-Mendocino 115 kV with Geyser #11 unit out	184

3.2.2.2.5 Effectiveness factors

Effectiveness factors for generators in the Eagle Rock LCR sub-area are in Attachment B table titled Eagle Rock.

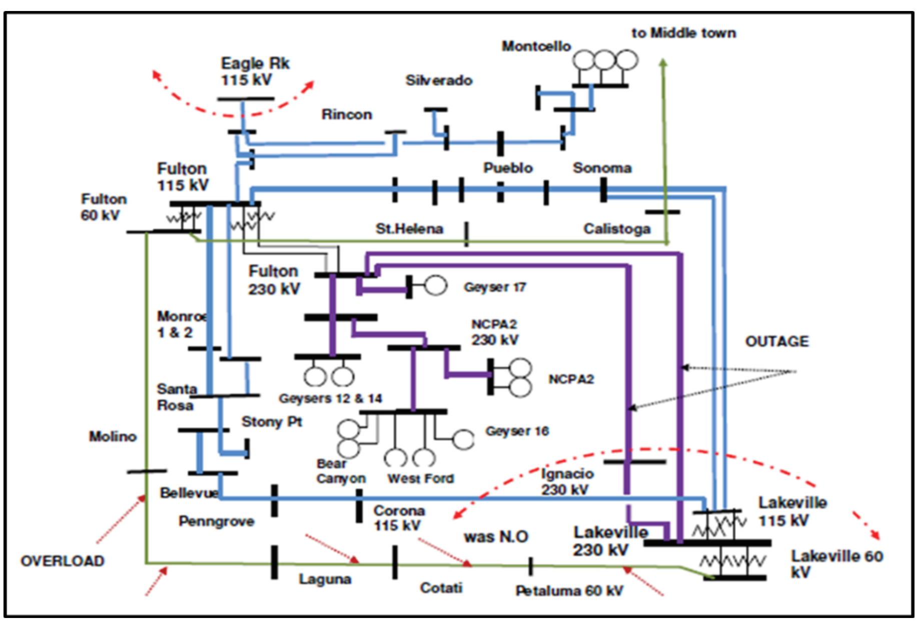
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7120 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.2.3 *Fulton Sub-area*

Fulton is a Sub-area of the North Coast and North Bay LCR Area.

3.2.2.3.1 Fulton LCR Sub-area Diagram

Figure 3.2-10 Fulton LCR Sub-area



3.2.2.3.2 Fulton LCR Sub-area Load and Resources

Table 3.2-6 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-6 Fulton LCR Area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	859	Market, Net Seller	469	469
AAEE	-9	MUNI	54	54
Behind the meter DG	0	QF	5	5
Net Load	**850**	Solar	0	0
Transmission Losses	22	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**872**	**Total**	**528**	**528**

3.2.2.3.3 Fulton LCR Sub-area Hourly Profiles

Figure 3.2-11 illustrates the forecast 2025 profile for the peak day for the Fulton LCR Sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-12 illustrates the forecast 2025 hourly profile for North Coast North Bay LCR Sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-11 Fulton LCR Sub-area 2025 Peak Day Forecast Profiles

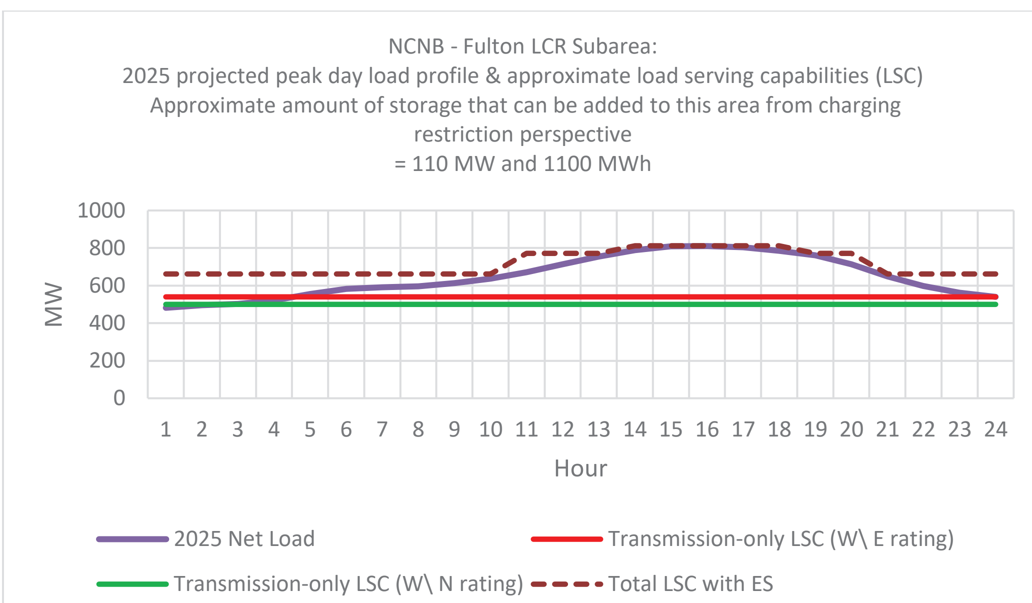
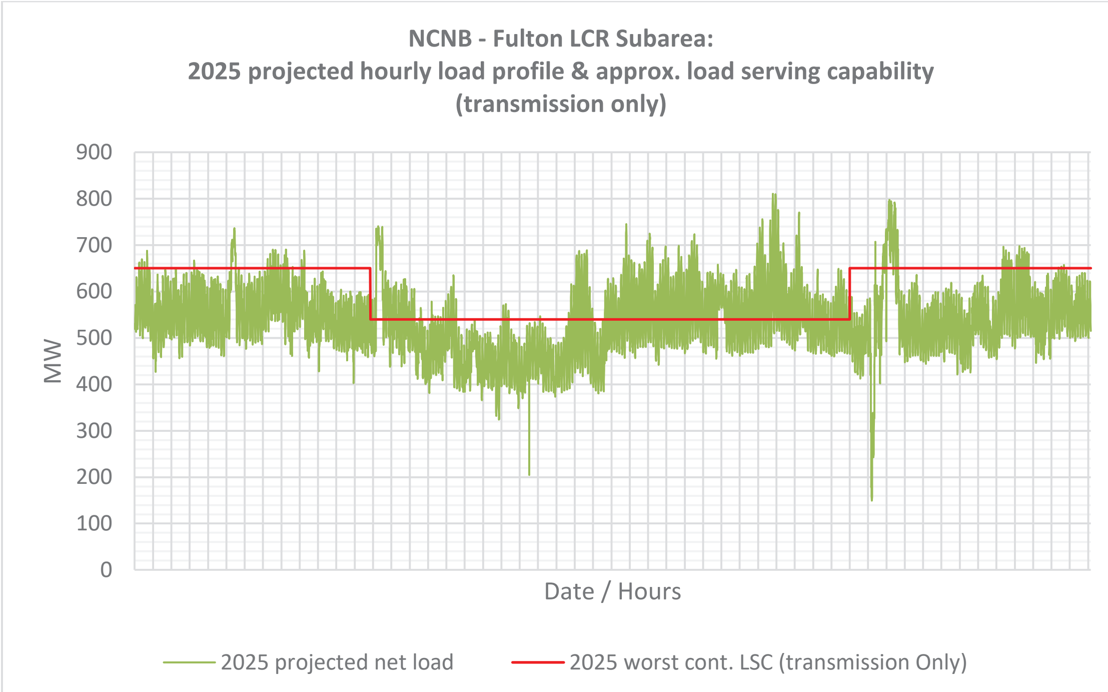


Figure 3.2-12 Fulton LCR Sub-area 2025 Forecast Hourly Profiles



3.2.2.3.4 Fulton LCR Sub-area Requirement

Table 3.2-7 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 272 MW. There is a significant LCR reduction because of the Lakeville 60 kV Area Reinforcement project in service in 2021 – to open the 60 kV line berween Cotati and Petaluma.

Table 3.2-7 Fulton LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Pengrove-Corona 115 kV line	Fulton-Lakeville #1 230 kV & Fulton-Ignacio #1 230 kV	272

3.2.2.3.5 Effectiveness factors

Effectiveness factors for generators in the Fulton LCR sub-area are in Attachment B table titled Fulton.

3.2.2.4 *North Coast and North Bay Overall*

3.2.2.4.1 North Coast and North Bay Overall Requirement

Table 3.2-8 identifies the sub-area LCR requirements. The LCR requirement for Category P2-4 contingency is 837 and for Category P3 contingency are 739 MW.

Table 3.2-8 North Coast and North Bay LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P2-4	Tulucay - Vaca Dixon 230 kV	Lakeville 230 kV – Section 2E & 1E	837
2025	Second Limit	P3	Vaca Dixon-Lakeville 230 kV	Vaca Dixon-Tulucay 230 kV with DEC power plant out of service	739

3.2.2.4.2 Effectiveness factors

Effectiveness factors for generators in the North Coast and North Bay LCR area are in Attachment B table titled Lakeville.

3.2.2.4.3 Changes compared to last year's results

Compared to 2024 load forecast went down by 56 MW; however, the total LCR need went up by 131 MW due to new contingency methdology (irrespective of) load decreaseLCR criteria.

3.2.3 Sierra Area

3.2.3.1 *Area Definition*

The transmission tie lines into the Sierra Area are:

Table Mountain-Rio Oso 230 kV line

Table Mountain-Palermo 230 kV line

Table Mt-Pease 60 kV line

Caribou-Palermo 115 kV line

Drum-Summit 115 kV line #1

Drum-Summit 115 kV line #2

Spaulding-Summit 60 kV line

Brighton-Bellota 230 kV line

Rio Oso-Lockeford 230 kV line

Gold Hill-Eight Mile Road 230 kV line

Lodi-Eight Mile Road 230 kV line

Gold Hill-Lake 230 kV line

The substations that delineate the Sierra Area are:

Table Mountain is out Rio Oso is in

Table Mountain is out Palermo is in

Table Mt is out Pease is in

Caribou is out Palermo is in

Drum is in Summit is out

Drum is in Summit is out

Spaulding is in Summit is out

Brighton is in Bellota is out

Rio Oso is in Lockeford is out

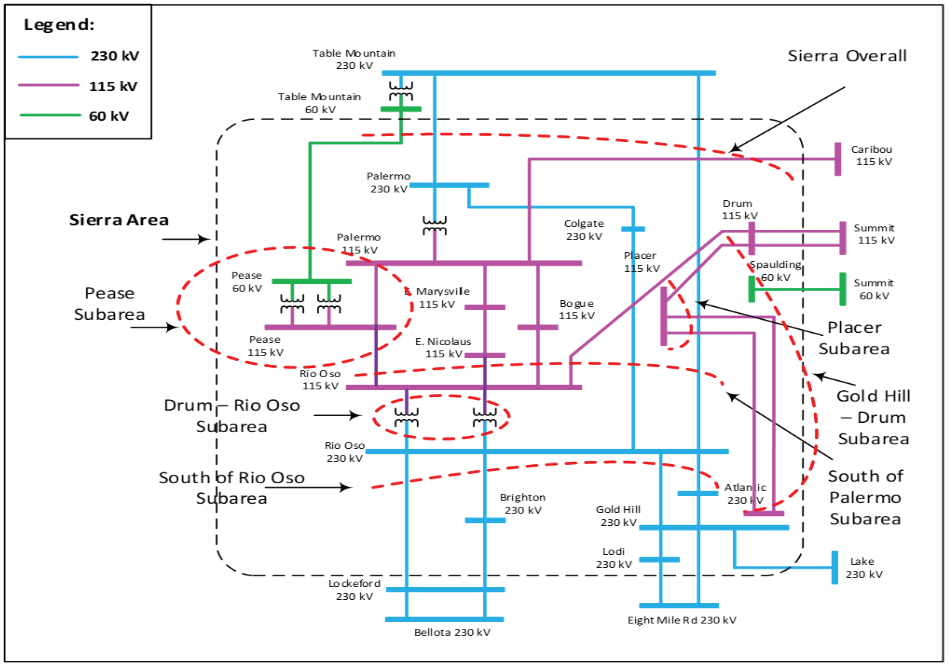
Gold Hill is in Eight Mile is out

Lodi is in Eight Mile is out

Gold Hill is in Lake is out

3.2.3.1.1 Sierra LCR Area Diagram

Figure 3.2-13 Sierra LCR Area



3.2.3.1.2 Sierra LCR Area Load and Resources

Table 3.2-9 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 19:00 PM.

At the local area peak time the estimated, ISO metered, solar output is 2.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-9 Sierra LCR Area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1849	Market, Net Seller	920	920
AAEE	-16	MUNI	1142	1142
Behind the meter DG	0	QF	41	41
Net Load	**1833**	Solar	5	0
Transmission Losses	85	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1918**	**Total**	**2108**	**2103**

3.2.3.1.3 Approved transmission projects modeled:

Rio Oso 230/115 kV transformer upgrade

Pease 115/60 kV transformer addition

South of Palermo 115 kV Reinforcement

Vaca Dixon Area Reinforcement

Rio Oso Area 230 kV Voltage Support

East Marysville 115/60 kV

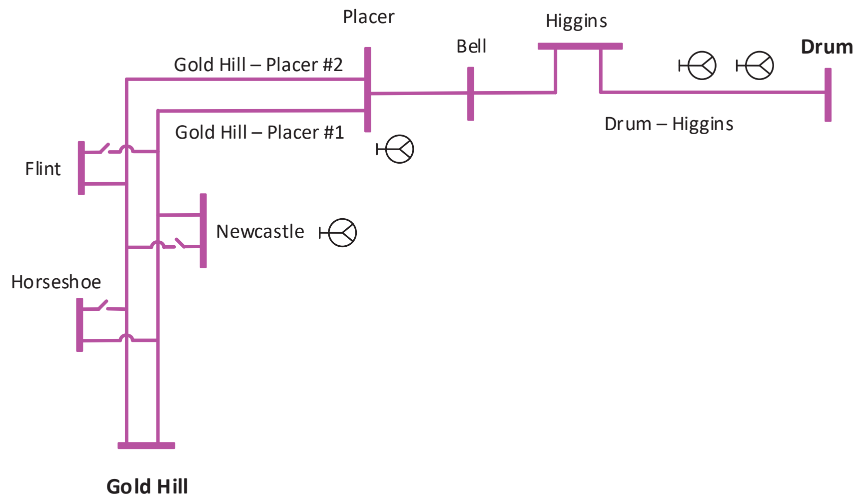
Gold Hill 230/115 kV Transformer Addition

3.2.3.2 *Placer Sub-area*

Placer is Sub-area of the Sierra LCR Area.

3.2.3.2.1 Placer LCR Sub-area Diagram

Figure 3.2-14 Placer LCR Sub-area



3.2.3.2.2 Placer LCR Sub-area Load and Resources

Table 3.2-10 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-10 Placer LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	175	Market, Net Seller	54	54
AAEE	-1	MUNI	42	42
Behind the meter DG	0	QF	0	0
Net Load	**174**	Solar	0	0
Transmission Losses	5	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**179**	**Total**	**96**	**96**

3.2.3.2.3 Placer LCR Sub-area Hourly Profiles

Figure 3.2-15 illustrates the forecast 2025 profile for the peak day for the Placer LCR sub-area with the Category P6 normal and emergency capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-16 illustrates the forecast 2025 hourly profile for Placer LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-15 Placer LCR Sub-area 2025 Peak Day Forecast Profiles

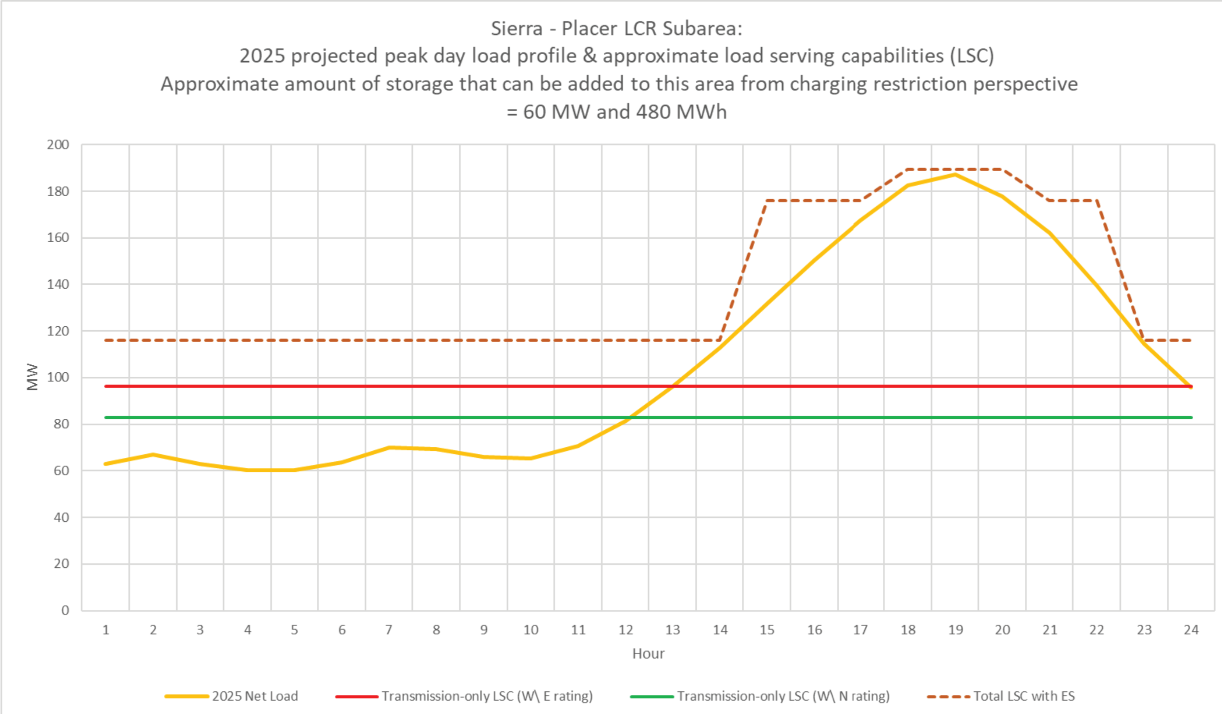
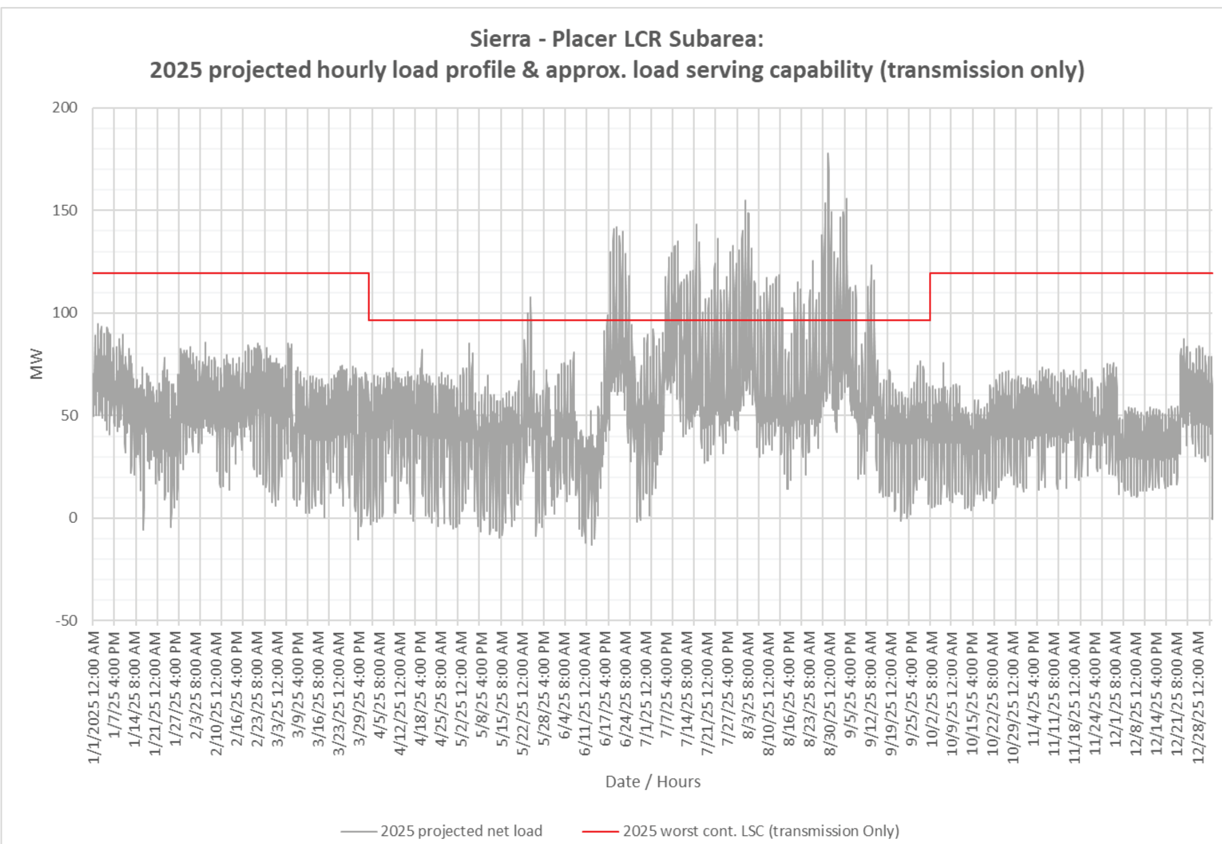


Figure 3.2-16 Placer LCR Sub-area 2025 Forecast Hourly Profiles



3.2.3.2.4 Placer LCR Sub-area Requirement

Table 3.2-11 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 93 MW.

Table 3.2-11 Placer LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Drum–Higgins 115 kV	Gold Hill-Placer #1 115 kV & Gold Hill-Placer #2 115 kV	93

3.2.3.2.5 Effectiveness factors

All units within the Placer Sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.3.3 *Pease Sub-area*

Pease is Sub-area of the Sierra LCR Area.

Pease Sub-area will be eliminated due to the East Marysville 115/60 kV transmission project .

3.2.3.4 *Drum-Rio Oso Sub-area*

Drum-Rio Oso is a Sub-area of the Sierra LCR Area.

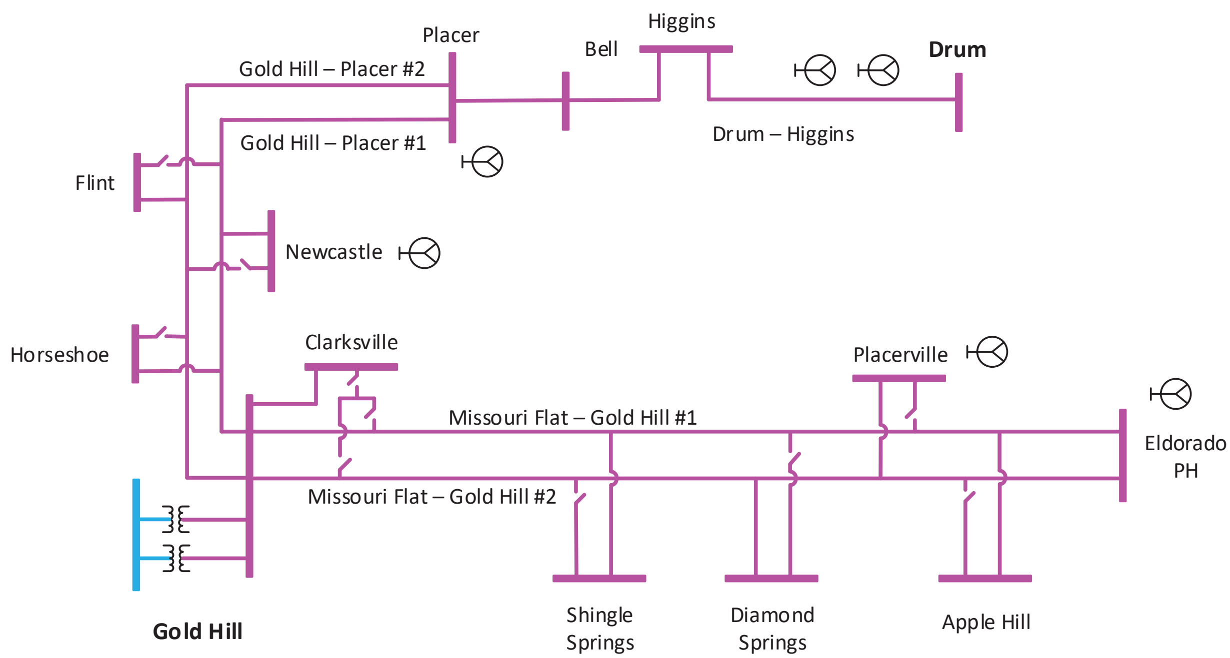
Drum-Rio Oso Sub-area will be eliminated due to the Rio Oso 230/115 kV transformer upgrade transmission project.

3.2.3.5 *Gold Hill-Drum Sub-area*

Gold Hill-Drum is Sub-area of the Sierra LCR Area.

3.2.3.5.1 Gold Hill-Drum LCR Sub-area Diagram

Figure 3.2-17 Gold Hill-Drum LCR Sub-area



3.2.3.5.2 Gold Hill-Drum LCR Sub-area Load and Resources

Table 3.2-12 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-12 Gold Hill-Drum LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	507	Market and Net Seller	85	85
AAEE	-4	MUNI	42	42
Behind the meter DG	0	QF	0	0
Net Load	**503**	Solar	0	0
Transmission Losses	9	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**512**	**Total**	**127**	**127**

3.2.3.5.3 Gold Hill-Drum LCR Sub-area Hourly Profiles

Figure 3.2-18 illustrates the forecast 2025 profile for the peak day for the Gold Hill-Drum LCR sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-19 illustrates the forecast 2021 hourly profile for Gold Hill-Drum LCR sub-area with the Category P6 load serving capability without local gas resources.

Figure 3.2-18 Gold Hill-Drum LCR Sub-area 2025 Peak Day Forecast Profiles

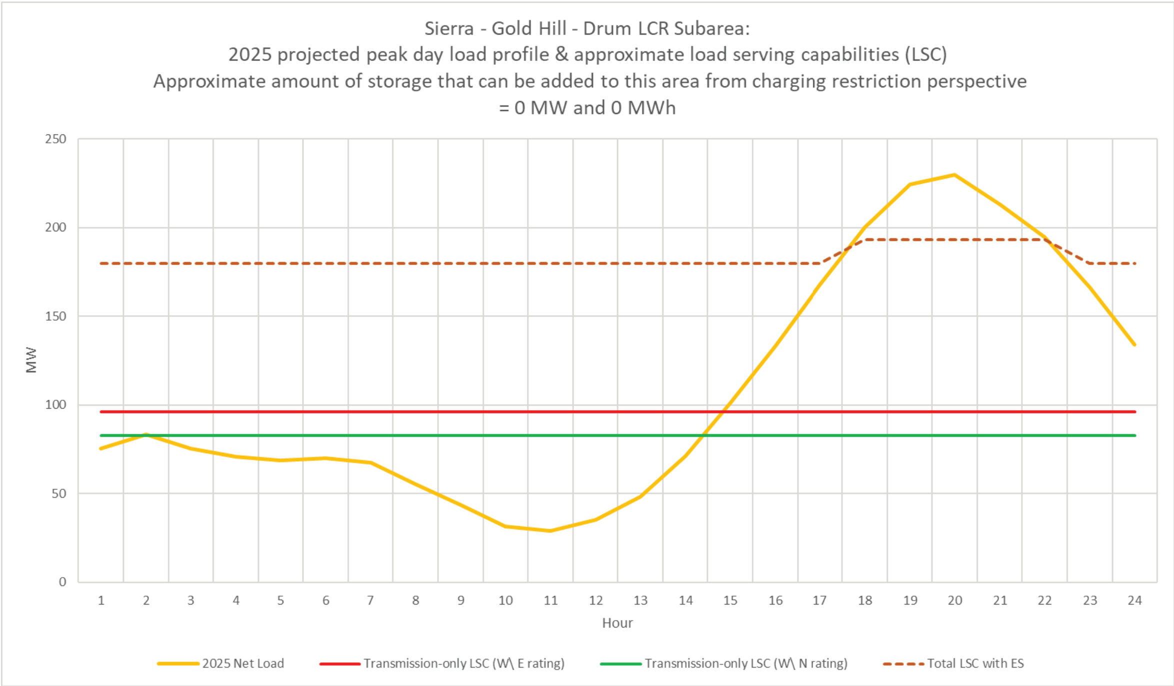
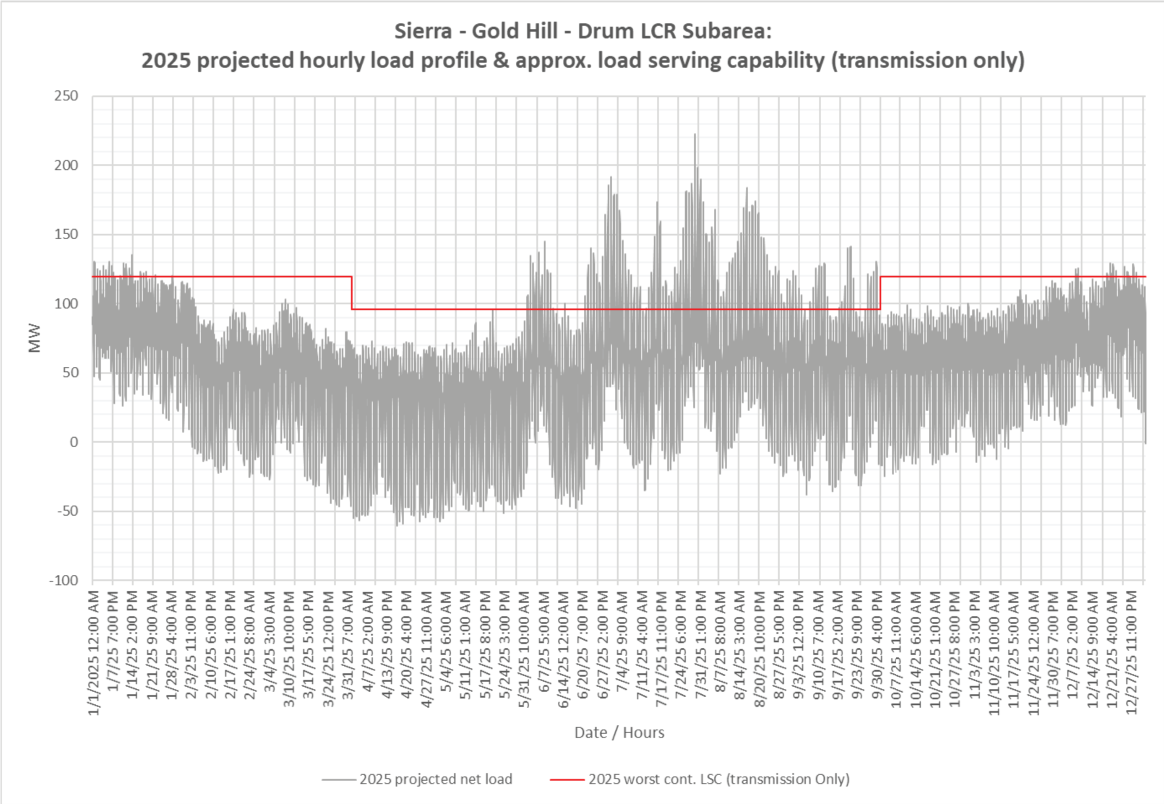


Figure 3.2-19 Gold Hill-Drum LCR Sub-area 2025 Forecast Hourly Profiles



3.2.3.5.4 Gold Hill-Drum LCR Sub-area Requirement

Table 3.2-13 identifies the sub-area LCR requirements. The Category P6 LCR requirement is 142 MW including 45 MW of NQC and peak deficiency .

Table 3.2-13 Gold Hill-Drum LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Drum – Higgins 115 kV	Bus-tie-breaker (P2-4) at Gold Hill 115 kV substation	142 (45)

3.2.3.5.5 Effectiveness factors:

All units within the Gold Hill-Drum sub-area have the same effectiveness factor.

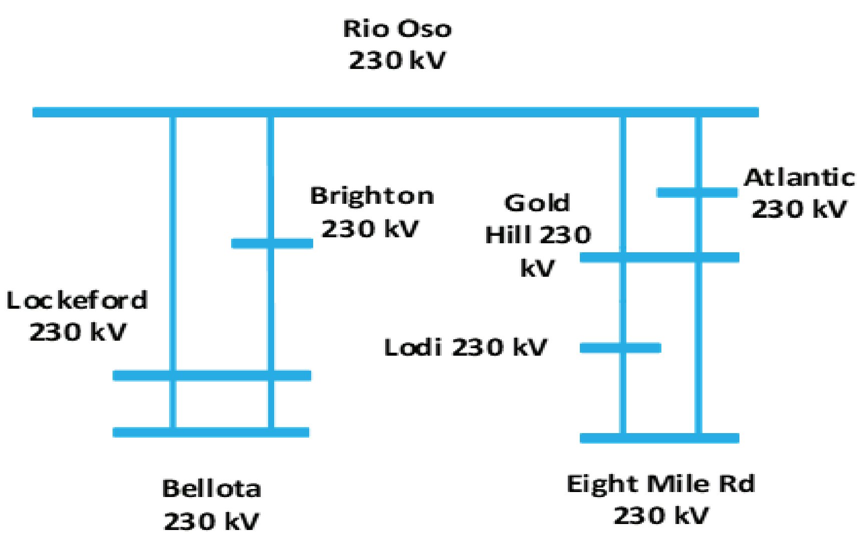
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 and 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.3.6 *South of Rio Oso Sub-area*

South of Rio Oso is a Sub-area of the Sierra LCR Area.

3.2.3.6.1 South of Rio Oso LCR Sub-area Diagram

Figure 3.2-20 South of Rio Oso LCR Sub-area



3.2.3.6.2 South of Rio Oso LCR Sub-area Load and Resources

The South of Rio Oso sub-area does not have a defined load pocket with the limits based upon power flow through the area. Table 3.2-14 provides the forecasted resources in the sub-area. The list of generators within the LCR area are provided in Attachment A.

Table 3.2-14 South of Rio Oso LCR Sub-area 2025 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The South of Rio Oso Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market	122	122
	MUNI	621	621
	QF	0	0
	LTPP Preferred Resources	0	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**743**	**743**

3.2.3.6.3 South of Rio Oso LCR Sub-area Hourly Profiles

The South of Rio Oso Sub-area does not have a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

3.2.3.6.4 South of Rio Oso LCR Sub-area Requirement

Table 3.2-15 identifies the sub-area LCR requirements. The LCR requirements for Category P6 contingency is 223 MW.

Table 3.2-15 South of Rio Oso LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P6	Rio Oso – Atlantic 230 kV	Rio Oso – Gold Hill 230 kV Rio Oso – Brighton 230 kV	223

3.2.3.6.5 Effectiveness factors:

Effectiveness factors for generators in the South of Rio Oso LCR sub-area are in Attachment B table titled Rio Oso.

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

3.2.3.7 *South of Palermo Sub-area*

South of Palermo sub-area will be eliminated due to the South of Palermo transmission project.

3.2.3.8 *Sierra Area Overall*

3.2.3.8.1 Sierra LCR Area Hourly Profiles

The Sierra LCR Area limits are based upon power flow through the area. As such, no load profile is provided for the area.

3.2.3.8.2 Sierra LCR Area Requirement

Table 3.2-16 identifies the area requirements. The LCR requirement for Category P6 contingency is 1367 MW.

Table 3.2-16 Sierra Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P6	Table Mountain – Pease 60 kV	Table Mountain – Palermo 230 kV Table Mountain – Rio Oso 230 kV	1367

3.2.3.8.3 Effectiveness factors:

Effectiveness factors for generators in the Sierra overall area are in Attachment B table titled Sierra Overall.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 and 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.3.8.4 Changes compared to last year's results:

The load forecast went up by 54 MW. The total LCR need has increased by 109 MW and the total existing capacity required has increased by 63 MW mostly due to increase in load forecast.

3.2.4 Stockton Area

The LCR requirement for the Stockton Area is driven by the Tesla-Bellota sub-area.

3.2.4.1 *Area Definition*

Tesla-Bellota Sub-Area Definition

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

Bellota 230/115 kV Transformer #1

Bellota 230/115 kV Transformer #2

Tesla-Tracy 115 kV Line

Tesla-Salado 115 kV Line

Tesla-Salado-Manteca 115 kV line

Tesla-Schulte #1 115 kV Line

Tesla-Schulte #2 115kV line

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

Bellota 230 kV is out Bellota 115 kV is in

Bellota 230 kV is out Bellota 115 kV is in

Tesla is out Tracy is in

Tesla is out Salado is in

Tesla is out Salado and Manteca are in

Tesla is out Schulte is in

Tesla is out Schulte is in

3.2.4.1.1 Stockton LCR Area Diagram

The Stockton LCR Area is comprised of the individual noncontiguous sub-areas with diagrams provided for each of the sub-areas below.

3.2.4.1.2 Stockton LCR Area Load and Resources

Table 3.2-17 provides the forecast load and resources in the area. The list of generators within the LCR area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 19:10 PM.

At the local area peak time the estimated, ISO metered, solar output is 2.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-17 Stockton LCR Area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**NQC**	**At Peak**
Gross Load	938	Market, Net Seller	491	491
AAEE	-7	MUNI	116	116
Behind the meter DG	0	QF	0	0
Net Load	**931**	Solar	12	0
Transmission Losses	19	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**950**	**Total**	**619**	**607**

3.2.4.1.3 Stockton LCR Area Hourly Profiles

The Stockton LCR Area is comprised of the individual noncontiguous sub-areas with profiles provided for each of the sub-areas below.

3.2.4.1.4 Approved transmission projects modeled

Weber-Stockton "A" #1 and #2 60 kV Reconductoring

Ripon 115 kV line

Vierra 115 kV Looping Project

Tesla 230 kV Bus Series Reactor

Lockeford-Lodi Area 230 kV Development

3.2.4.2 *Weber Sub-area*

Weber sub-area has been eliminated due to change in LCR criteria.

3.2.4.3 *Lockeford Sub-area*

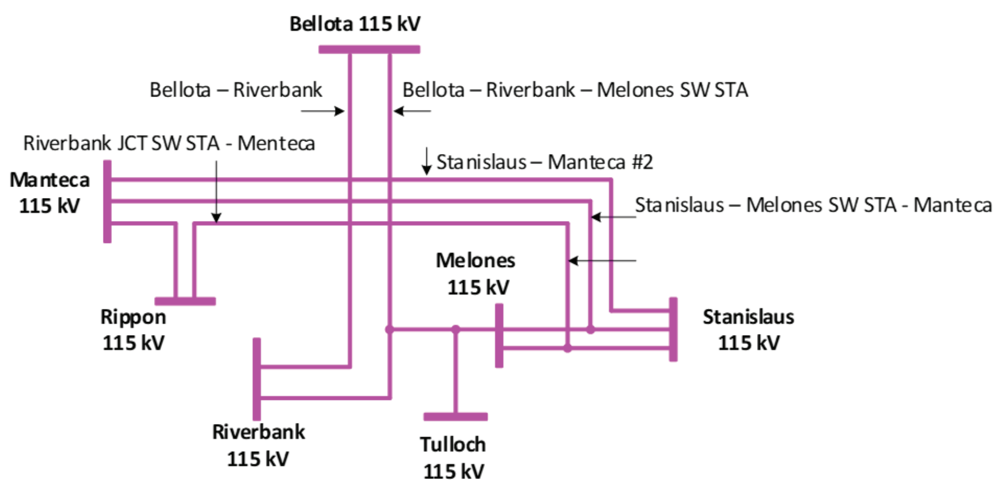
Lockeford sub-area will be eliminated due to the Lockeford-Lodi Area 230 kV Development transmission project.

3.2.4.4 *Stanislaus Sub-area*

Stanislaus is a Sub-area within the Tesla-Bellota Sub-area of the Stockton LCR Area.

3.2.4.4.1 Stanislaus LCR Sub-area Diagram

Figure 3.2-21 Stanislaus LCR Sub-area



3.2.4.4.2 Stanislaus LCR Sub-area Load and Resources

The Stanislaus sub-area does not has a defined load pocket with the limits based upon power flow through the area. Table 3.2-18 provides the forecasted resources in the sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-18 Stanislaus LCR Sub-area 2025 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Stanislaus Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller	117	117
	MUNI	94	94
	QF	0	0
	Solar	0	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**211**	**211**

3.2.4.4.3 Stanislaus LCR Sub-area Hourly Profiles

The Stanislaus Sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

3.2.4.4.4 Stanislaus LCR Sub-area Requirement

Table 3.2-19 identifies the sub-area requirements. The LCR requirement for Category P3 contingency is 213 MW including 2 MW deficiency.

Table 3.2-19 Stanislaus LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P3	Manteca – Ripon 115 kV	Bellota-Riverbank-Melones 115 kV and Stanislaus PH	213 (2)

3.2.4.4.5 Effectiveness factors:

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

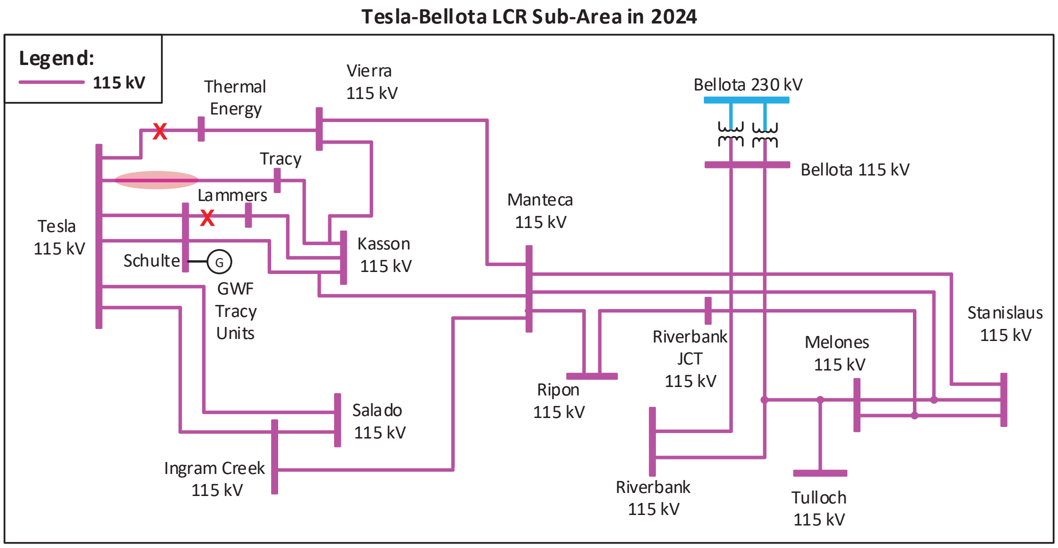
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7410 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.4.5 *Tesla-Bellota Sub-area*

Tesla-Bellota is a Sub-area of the Stockton LCR Area.

3.2.4.5.1 Tesla-Bellota LCR Sub-area Diagram

Figure 3.2-22 Tesla-Bellota LCR Sub-area



3.2.4.5.2 Tesla Bellota LCR Sub-area Load and Resources

Table 3.2-20 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-20 Tesla-Bellota LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	938	Market, Net Seller	491	491
AAEE	-7	MUNI	116	116
Behind the meter DG	0	QF	0	0
Net Load	**931**	LTPP Preferred Resources	12	0
Transmission Losses	19	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**950**	**Total**	**619**	**607**

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

3.2.4.5.3 Tesla-Bellota LCR Sub-area Hourly Profiles

Figure 3.2-23 illustrates the forecast 2025 profile for the peak day for the Tesla-Bellota sub-area with the Category P6 normal and emergency load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-24 illustrates the forecast 2025 hourly profile for Tesla-Bellota sub-area with of the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-23 Tesla-Bellota LCR Sub-area 2025 Peak Day Forecast Profiles

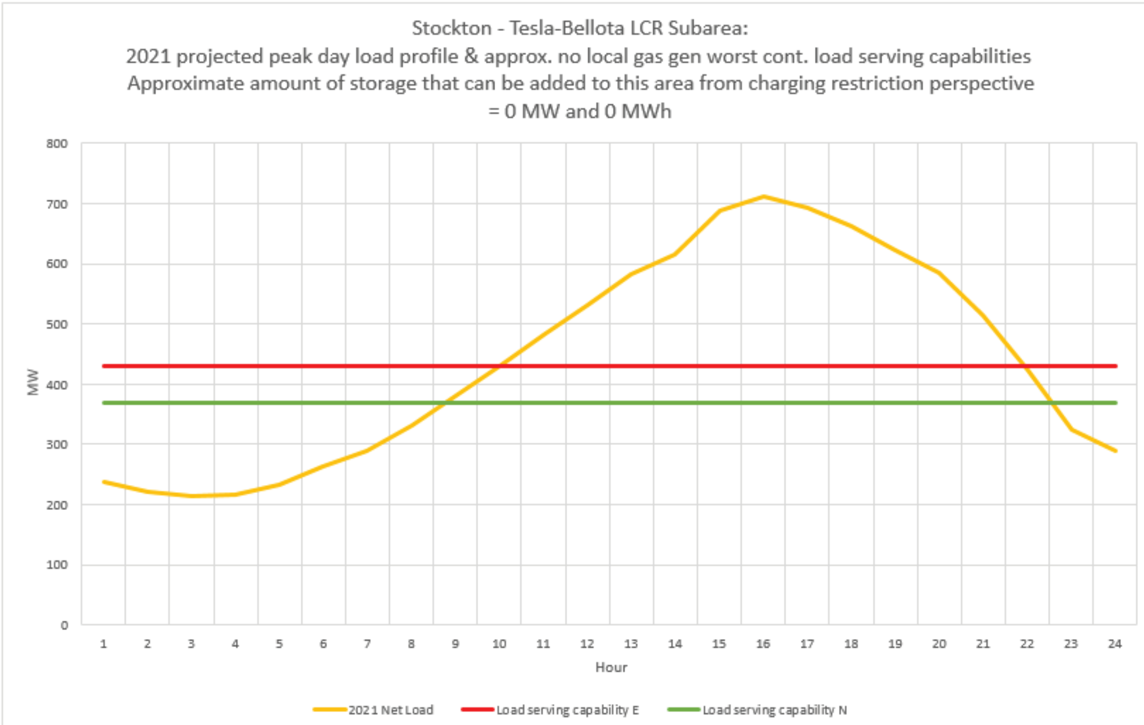
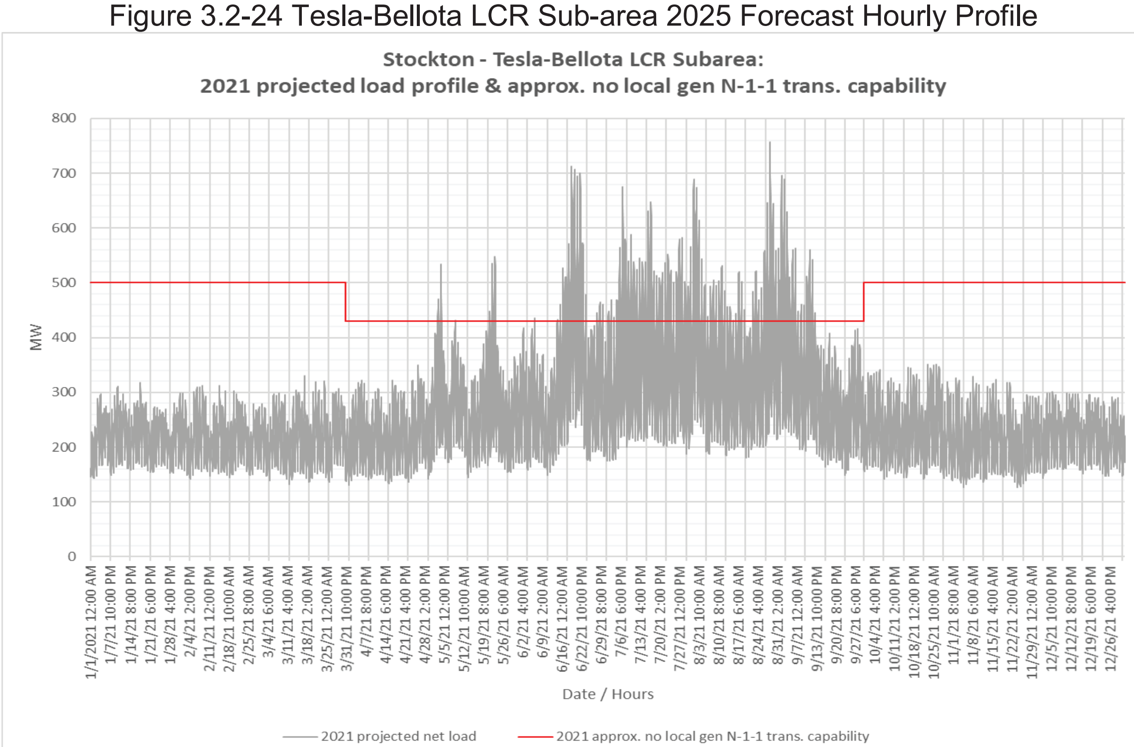


Figure 3.2-24 Tesla-Bellota LCR Sub-area 2025 Forecast Hourly Profile



3.2.4.5.4 Tesla-Bellota LCR Sub-area Requirement

Table 3.2-21 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 741 MW including a 122 MW of NQC deficiency or 134 MW of at peak deficiency.

Table 3.2-21 Tesla-Bellota LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P6	Stanislaus – Melones – Riverbank Jct 115 kV	Tesla 115 kV Bus	674 (55 NQC/ 67 Peak)
2025	First limit	P6	Tesla – Vierra 115 kV	Schulte – Lammers 115 kV & Schulte-Kasson-Manteca 115 kV	431 (122 NQC/ 134 Peak)
Total LCR Need for Tesla – Bellota Sub-area in 2025					741 (122 NQC/ 134 Peak)

3.2.4.5.5 Effectiveness factors:

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7410 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.4.6 *Stockton Overall*

3.2.4.6.1 Stockton LCR Area Overall Requirement

The requirement for this area is driven by the requirement for the Tesla-Bellota sub-area. Table 3.2-22 identifies the area requirements. The LCR requirement for Category P6 contingency is 741 MW with a 122 MW NQC deficiency or 134 MW at peak deficiency.

Table 3.2-22 Stockton LCR Sub-area Overall Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025		P6	Stockton Overall		741 (122 NQC/ 134 Peak)

3.2.4.6.2 Changes compared to 2024 LCT study

The load forecast went down by 379 MW due to the elimination of the Weber and Lockeford sub-areas, otherwise the load forecast would have gone up by 65 MW. The total LCR need has decreased by 268 MW due to transmission development and change in criteria.

3.2.5 Greater Bay Area

3.2.5.1 *Area Definition:*

The transmission tie lines into the Greater Bay Area are:

Lakeville-Sobrante 230 kV

Ignacio-Sobrante 230 kV

Parkway-Moraga 230 kV

Bahia-Moraga 230 kV

Lambie SW Sta-Vaca Dixon 230 kV

Peabody-Contra Costa P.P. 230 kV

Tesla-Kelso 230 kV

Tesla-Delta Switching Yard 230 kV

Tesla-Pittsburg #1 230 kV

Tesla-Pittsburg #2 230 kV

Tesla-Newark #1 230 kV

Tesla-Newark #2 230 kV

Tesla-Ravenswood 230 kV

Tesla-Metcalf 500 kV

Moss Landing-Metcalf 500 kV

Moss Landing-Metcalf #1 230 kV

Moss Landing-Metcalf #2 230 kV

Oakdale TID-Newark #1 115 kV

Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

Lakeville is out Sobrante is in

Ignacio is out Sobrante is in

Parkway is out Moraga is in

Bahia is out Moraga is in

Lambie SW Sta is in Vaca Dixon is out

Peabody is out Contra Costa P.P. is in

Tesla is out Kelso is in

Tesla is out Delta Switching Yard is in

Tesla is out Pittsburg is in

Tesla is out Pittsburg is in

Tesla is out Newark is in

Tesla is out Newark is in

Tesla is out Ravenswood is in

Tesla is out Metcalf is in

Moss Landing is out Metcalf is in

Moss Landing is out Metcalf is in

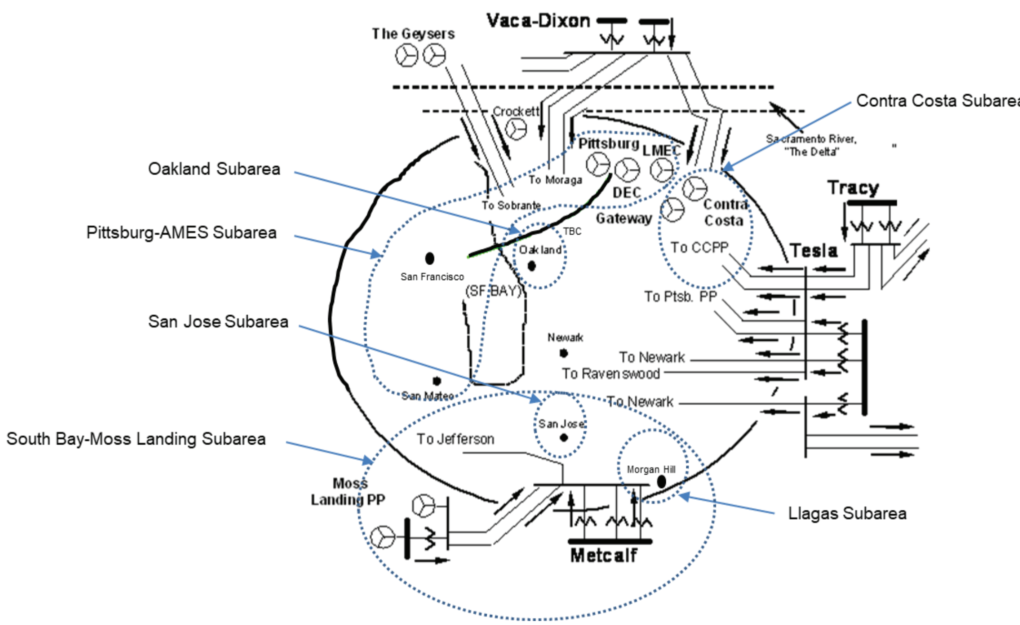
Moss Landing is out Metcalf is in

Oakdale TID is out Newark is in

Oakdale TID is out Newark is in

3.2.5.1.1 Greater Bay LCR Area Diagram

Figure 3.2-25 Greater Bay LCR Area



3.2.5.1.2 Greater Bay LCR Area Load and Resources

Table 3.2-23 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 17:50 PM.

At the local area peak time the estimated, ISO metered, solar output is 44.00%.

If required, all technology type resources, including solar, are dispatched at NQC.

Table 3.2-23 Greater Bay Area LCR Area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	10606	Market, Net Seller, Battery, Wind	6138	6138
AAEE	-120	MUNI	377	377
Behind the meter DG	-247	QF	227	227
Net Load	**10239**	Solar	8	8
Transmission Losses	240	Existing 20-minute Demand Response	0	0
Pumps	264	Future preferred resource and energy storage	594	594
Load + Losses + Pumps	**10743**	**Total**	**7344**	**7344**

3.2.5.1.3 Approved transmission projects modeled

Oakland Clean Energy Initiative Project (Oakland CTs are assumed retired)

Morgan Hill Area Reinforcement (revised scope)

Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade

East Shore-Oakland J 115 kV Reconductoring Project

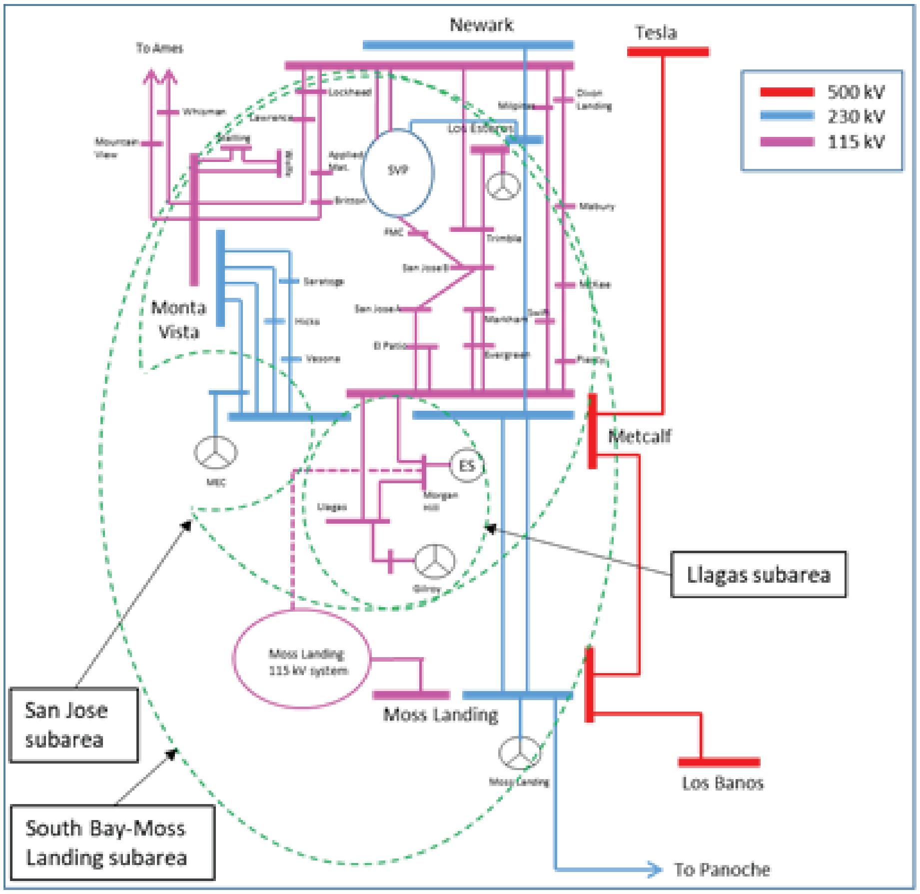
Vaca Dixon-Lakeville 230 kV Corridor Series Compensation

3.2.5.2 *Llagas Sub-area*

Llagas is a Sub-area of the Greater Bay LCR Area.

3.2.5.2.1 Llagas LCR Sub-area Diagram

Figure 3.2-26 Llagas LCR Sub-area



3.2.5.2.2 Llagas LCR Sub-area Load and Resources

Table 3.2-24 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-24 Llagas LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	212	Market, Net Seller, Battery, Solar	246	246
AAEE	-3	MUNI	0	0
Behind the meter DG	-8	QF	0	0
Net Load	**201**	LTPP Preferred Resources	0	0
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**201**	**Total**	**246**	**246**

3.2.5.2.3 Llagas LCR Sub-area Hourly Profiles

Figure 3.2-27 illustrates the forecast 2025 profile for the peak day for the Llagas LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-28 illustrates the forecast 2025 hourly profile for Llagas LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-27 Llagas LCR Sub-area 2025 Peak Day Forecast Profiles

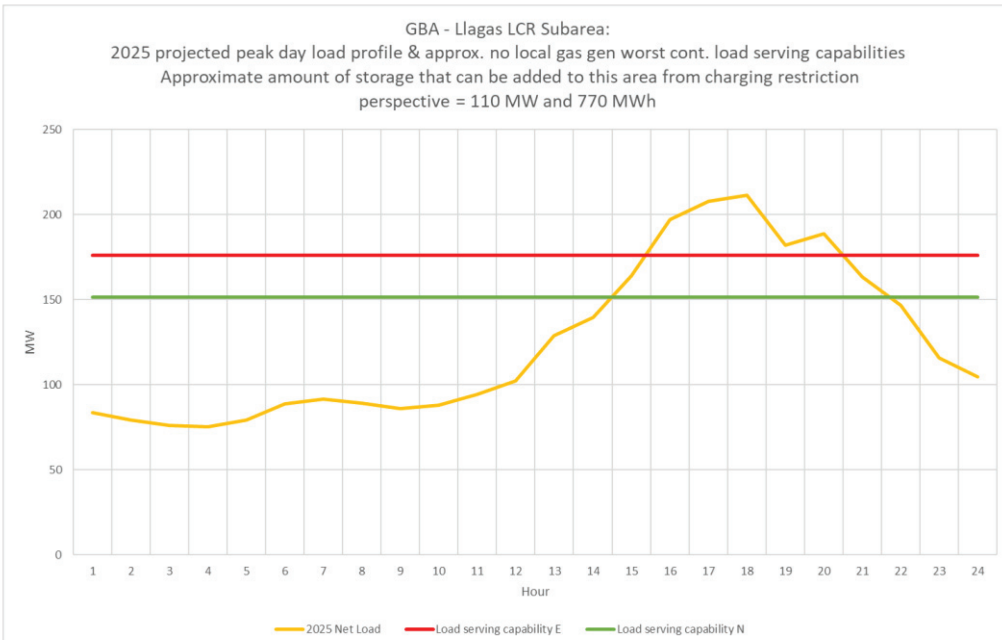
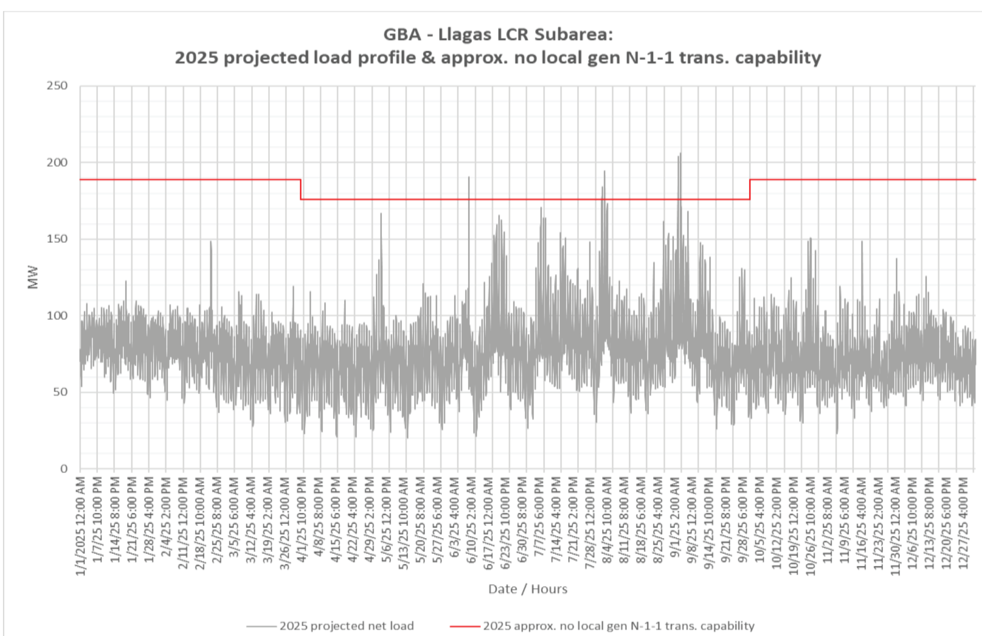


Figure 3.2-28 Llagas LCR Sub-area 2025 Forecast Hourly Profiles



3.2.5.2.4 Llagas LCR Sub-area Requirement

Table 3.2-25 identifies the sub-area LCR requirements. The LCR requirement for the Category P6 contingency is 33 MW.

Table 3.2-25 Llagas LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2025	First limit	P6	Metcalf-Llagas 115 kV	Metcalf-Morgan Hill 115 kV & Morgan Hill-Green Valley 115 kV	33

3.2.5.2.5 **Effectiveness factors:**

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

3.2.5.3 *San Jose Sub-area*

San Jose is a Sub-area of the Greater Bay LCR Area.

3.2.5.3.1 San Jose LCR Sub-area Diagram

The San Jose LCR Sub-area is identified in Figure 3.2-26.

3.2.5.3.2 San Jose LCR Sub-area Load and Resources

Table 3.2-26 provides the forecast load and resources in San Jose LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-26 San Jose LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	2544	Market, Net Seller, Battery, Solar	575	575
AAEE	-32	MUNI	198	198
Behind the meter DG	-53	QF	0	0
Net Load	**2459**	LTPP Preferred Resources	75	75
Transmission Losses	68	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**2527**	**Total**	**848**	**848**

3.2.5.3.3 San Jose LCR Sub-area Hourly Profiles

Figure 3.2-29 illustrates the forecast 2025 profile for the peak day for the San Jose LCR sub-area with the Category P2 normal and emergengy load serving capabilities without local gas resources.

The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-30 illustrates the forecast 2025 hourly profile for San Jose LCR sub-area with the Category P2emergency load serving capability without local gas resources.

Figure 3.2-29 San Jose LCR Sub-area 2025 Peak Day Forecast Profiles

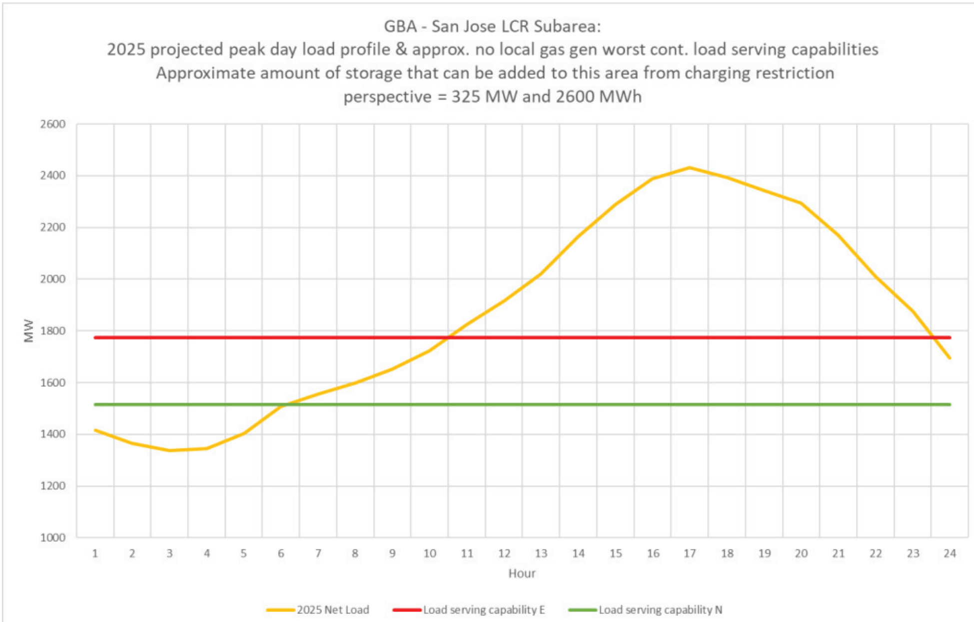
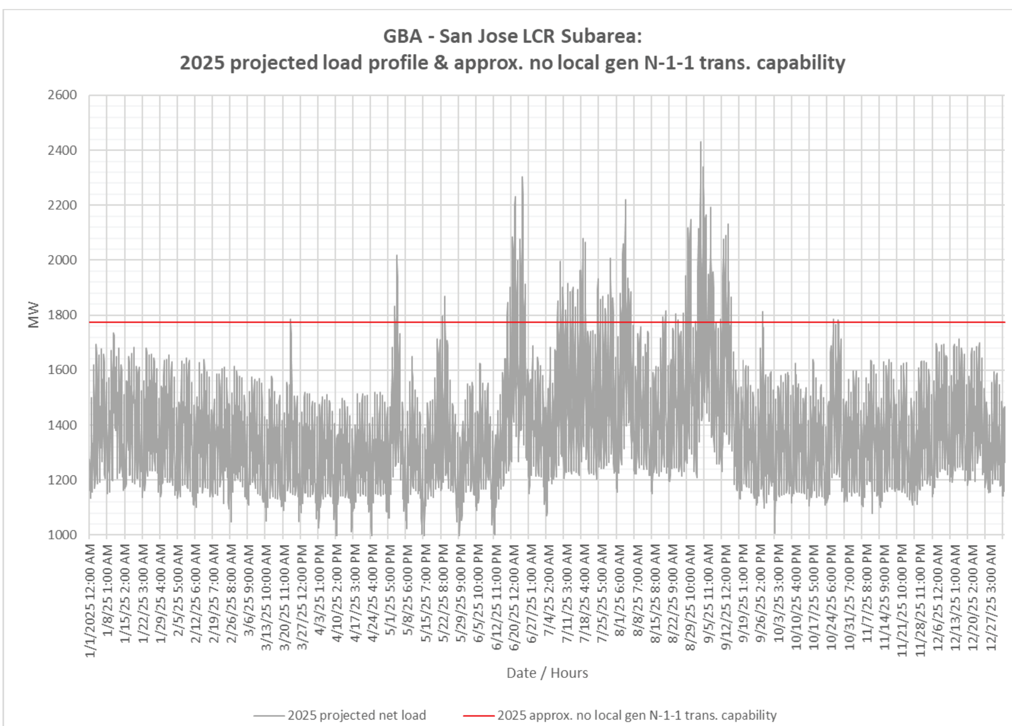


Figure 3.2-30 San Jose LCR Sub-area 2025 Forecast Hourly Profiles



3.2.5.3.4 San Jose LCR Sub-area Requirement

Table 3.2-27 identifies the sub-area LCR requirements. The LCR requirement for the Category P2 contingency is 862 MW wchich includes deficiency of 14 MW.

Table 3.2-27 San Jose LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P2	Metcalf 230/115 kV transformer # 1 or # 3	Metcalf 230kV - Section 2D & 2E	862 (14)

3.2.5.3.5 Effectiveness factors:

Effectiveness factors for generators in the San Jose LCR sub-area are in Attachment B table titled San Jose.

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

3.2.5.4 *South Bay-Moss Landing Sub-area*

South Bay-Moss Landing is a Sub-area of the Greater Bay LCR Area.

3.2.5.4.1 South Bay-Moss Landing LCR Sub-area Diagram

The South Bay-Moss Landing LCR sub-area is identified in Figure 3.2-26.

3.2.5.4.2 South Bay-Moss Landing LCR Sub-area Load and Resources

Table 3.2-28 provides the forecast load and resources in South Bay-Moss Landing LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-28 South Bay-Moss Landing LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4165	Market, Net Seller, Battery, Solar	2165	2165
AAEE	-52	MUNI	198	198
Behind the meter DG	-101	QF	0	0
Net Load	**4012**	LTPP Preferred Resources	558	558
Transmission Losses	112	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**4124**	**Total**	**2921**	**2921**

3.2.5.4.3 South Bay-Moss Landing LCR Sub-area Hourly Profiles

Figure 3.2-31 illustrates the forecast 2025 profile for the peak day for the South Bay-Moss Landing LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-32 illustrates the forecast 2025 hourly profile for South Bay-Moss Landing LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-31 South Bay-Moss Landing LCR Sub-area 2025 Peak Day Forecast Profiles

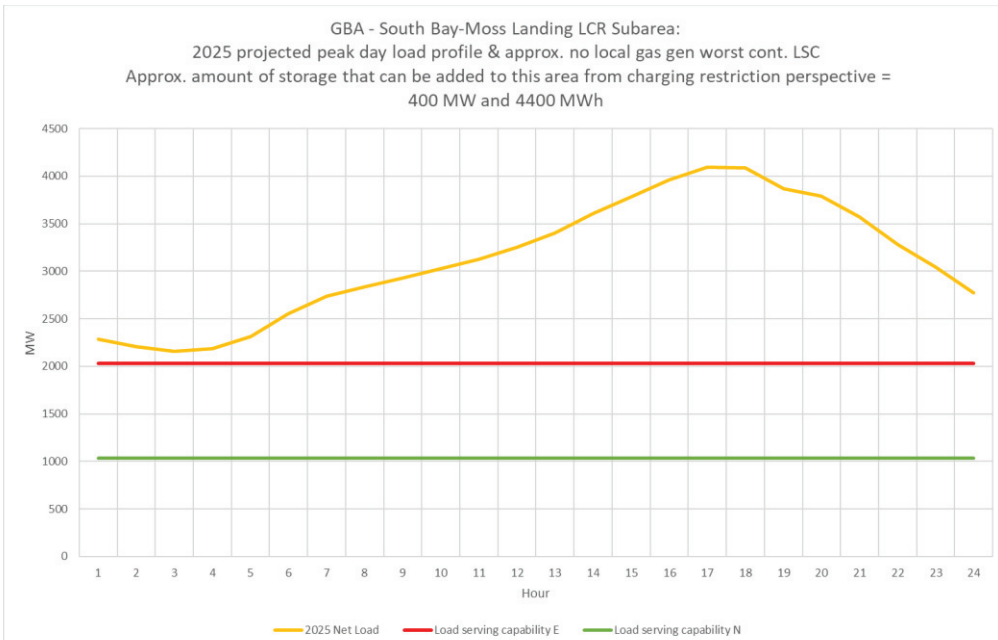
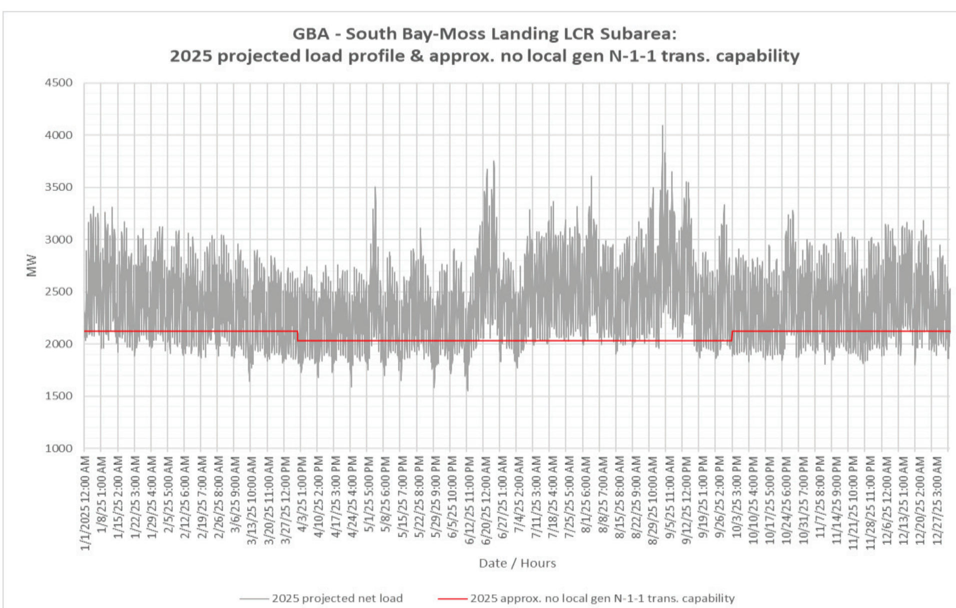


Figure 3.2-32 South Bay-Moss Landing LCR Sub-area 2025 Forecast Hourly Profiles



3.2.5.4.4 South Bay-Moss Landing LCR Sub- Requirement

Table 3.2-29 identifies the sub-area LCR requirements. The LCR requirement for the Category P6 contingency is 1834 MW.

Table 3.2-29 South Bay-Moss Landing LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2025	First Limit	P6	Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	1834

3.2.5.4.5 Effectiveness factors:

Effectiveness factors for generators in the South Bay-Moss Landing LCR sub-area are in Attachment B table titled South Bay-Moss Landing.

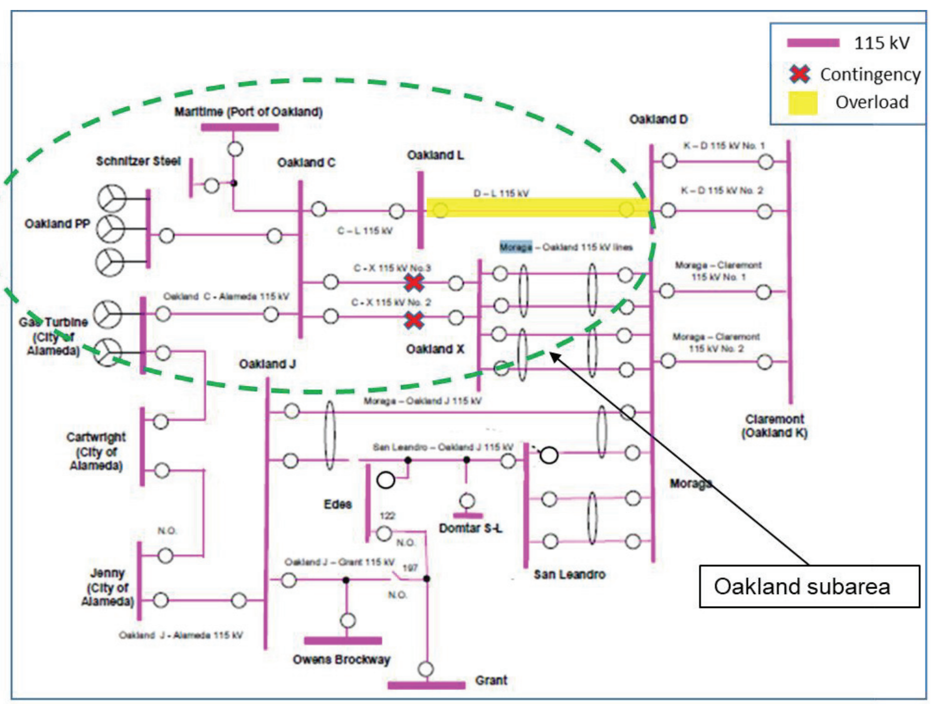
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 (T-165Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.5.5 *Oakland Sub-area*

Oakland is a Sub-area of the Greater Bay LCR Area.

3.2.5.5.1 Oakland LCR Sub-area Diagram

Figure 3.2-33 Oakland LCR Sub-area



3.2.5.5.2 Oakland LCR Sub-area Load and Resources

Table 3.2-30 provides the forecast load and resources in Oakland LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-30 Oakland LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	225	Market, Net Seller, Battery, Solar	0	0
AAEE	-3	MUNI	48	48
Behind the meter DG	-3	QF	0	0
Net Load	**219**	LTPP Preferred Resources	36	36
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**219**	**Total**	**84**	**84**

3.2.5.5.3 Oakland LCR Sub-area Hourly Profiles

Figure 3.2-34 illustrates the forecast 2025 profile for the peak day for the Oakland LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-35 illustrates the forecast 2025 hourly profile for Oakland LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-34 Oakland LCR Sub-area 2025 Peak Day Forecast Profiles

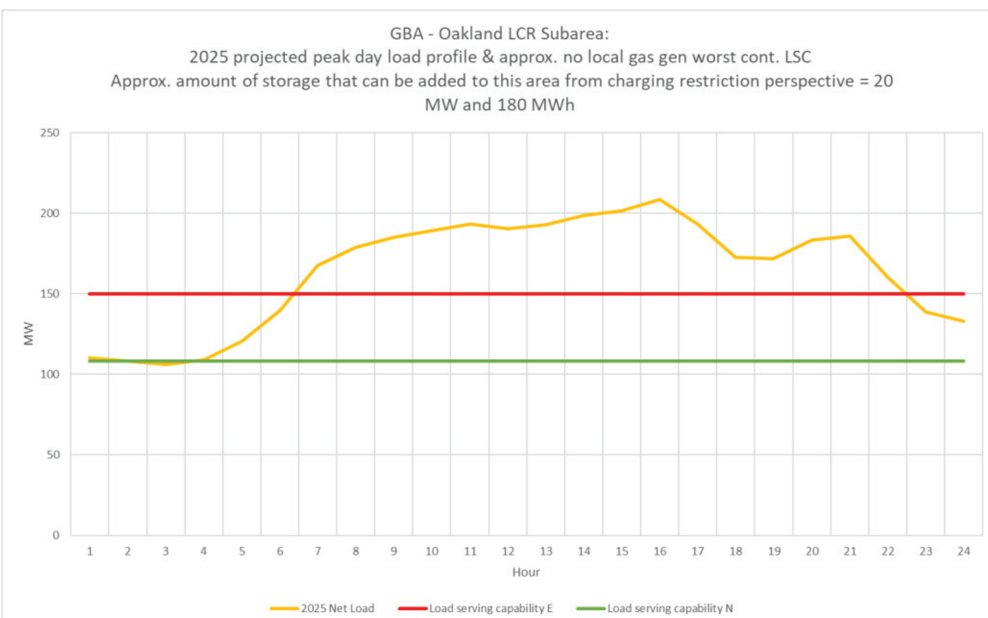
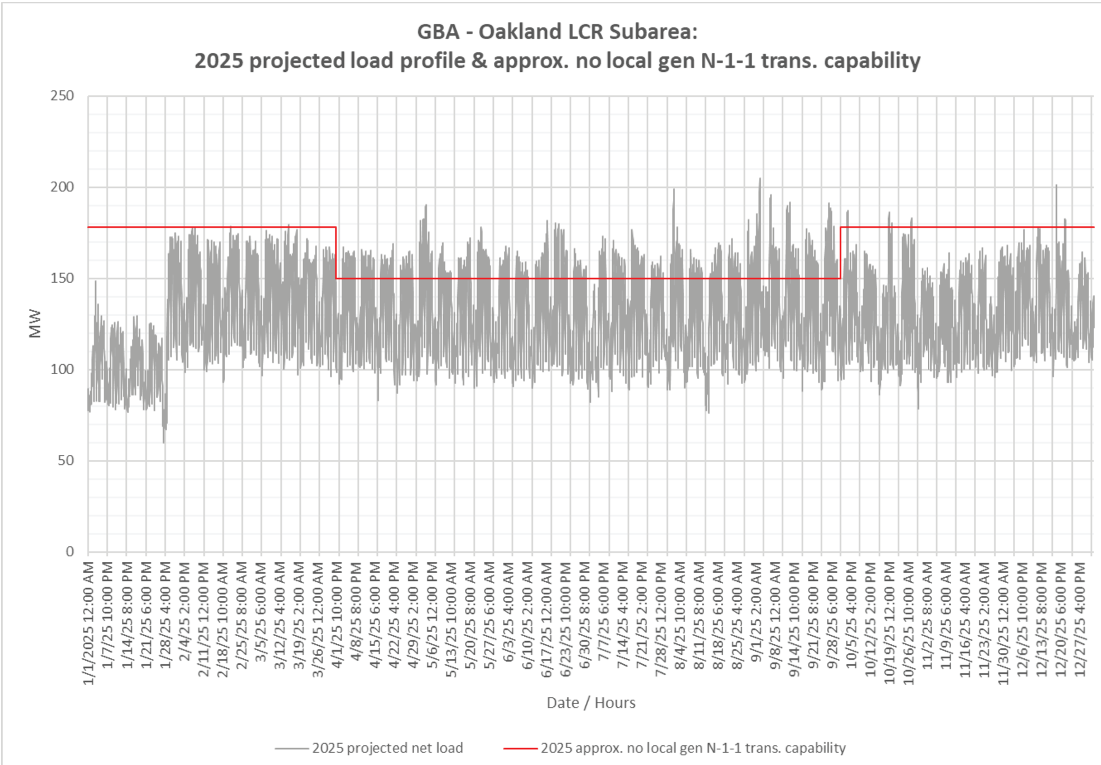


Figure 3.2-35 Oakland LCR Sub-area 2025 Forecast Hourly Profiles



3.2.5.5.4 Oakland LCR Sub-area Requirement

Table 3.2-31 identifies the sub-area requirements. The LCR requirement for the Category P6 contingency is 71 MW.

Table 3.2-31 Oakland LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2025	First limit	P6	Moraga-Claremont #2 115 kV cable	Oakland C-X #2 & #3 115 kV	71[8]

3.2.5.5.5 **Effectiveness factors:**

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

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

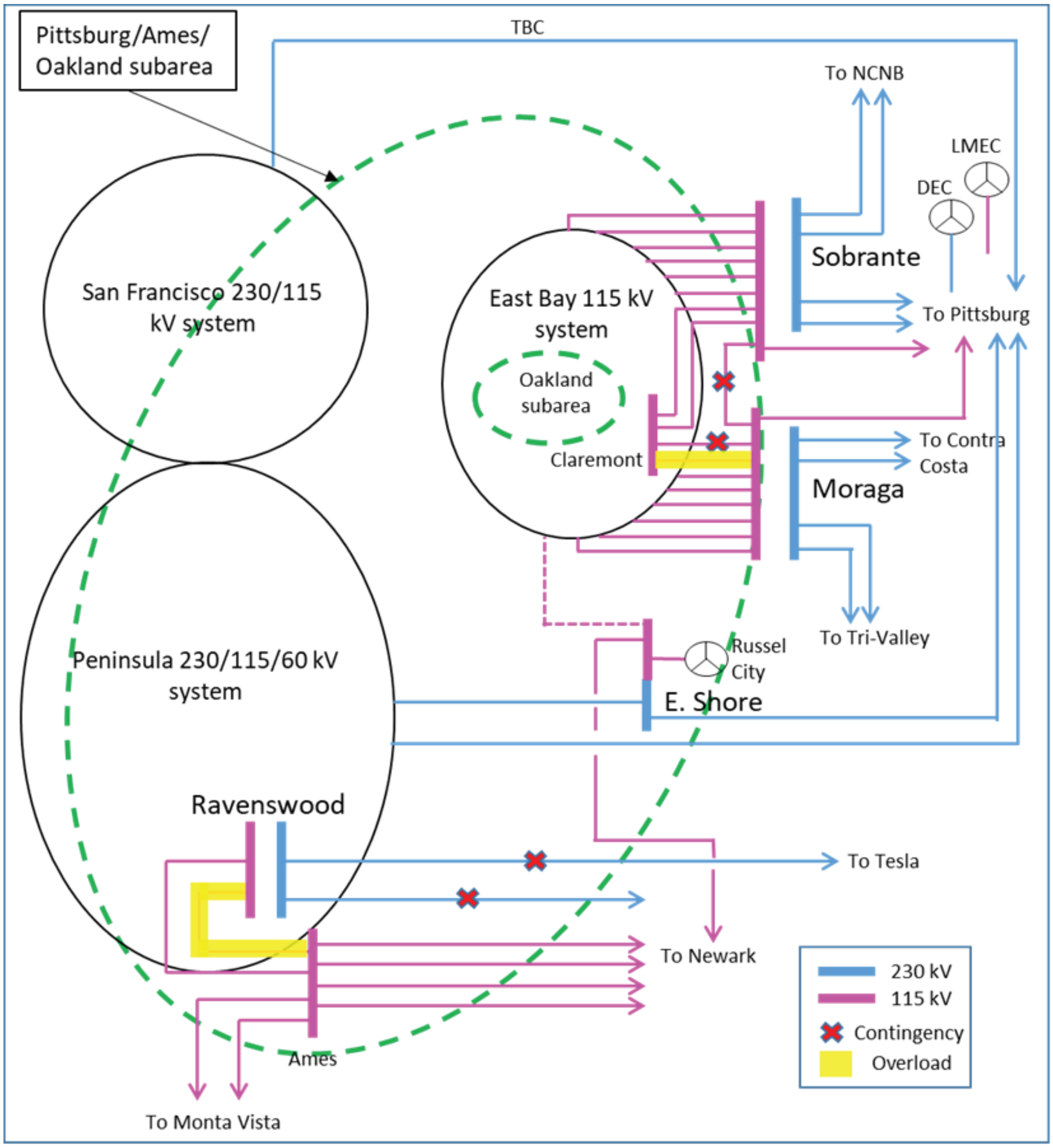
[8] This requirement doesn't reflect potential load transfer that could occur following the first contingency. An approved operating procedure including this load transfer could reduce this requirement.

3.2.5.6 *Ames-Pittsburg-Oakland Sub-areas Combined*

Ames-Pittsburg-Oakland is a Sub-area of the Greater Bay LCR Area.

3.2.5.6.1 Ames-Pittsburg-Oakland LCR Sub-area Diagram

Figure 3.2-36 Ames-Pittsburg-Oakland LCR Sub-area



3.2.5.6.2 Ames-Pittsburg-Oakland LCR Sub-area Load and Resources

Table 3.2-32 provides the forecast load and resources in Ames-Pittsburg-Oakland LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-32 Ames-Pittsburg-Oakland LCR Sub-area 2025 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Ames-Pittsburg-Oakland Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller, Battery, Wind	2152	2152
	MUNI	48	48
	QF	225	225
	Solar	5	5
	Existing 20-minute Demand Response	0	0
	LTPP Preferred Resources	36	36
	Total	**2466**	**2466**

3.2.5.6.3 Ames-Pittsburg-Oakland LCR Sub-area Hourly Profiles

The Ames-Pittsburg-Oakland Sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

3.2.5.6.4 Ames-Pittsburg-Oakland LCR Sub-area Requirement

Table 3.2-33 identifies the sub-area LCR requirements. The LCR requirement for the Category P7 or P2 contingency is 1761 MW.

Table 3.2-33 Ames-Pittsburg-Oakland LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2025	First limit	P7	Ames-Ravenswood #1 115 kV line	Newark-Ravenswood 230 kV & Tesla-Ravenswood 230 kV	1761
		P2	Martinez-Sobrante 115 kV line	Pittsburg Section 1D & 1E 230kV	

3.2.5.6.5 **Effectiveness factors:**

Effectiveness factors for generators in the Ames-Pittsburg-Oakland LCR sub-area are in Attachment B table titled Ames/Pittsburg/Oakland.

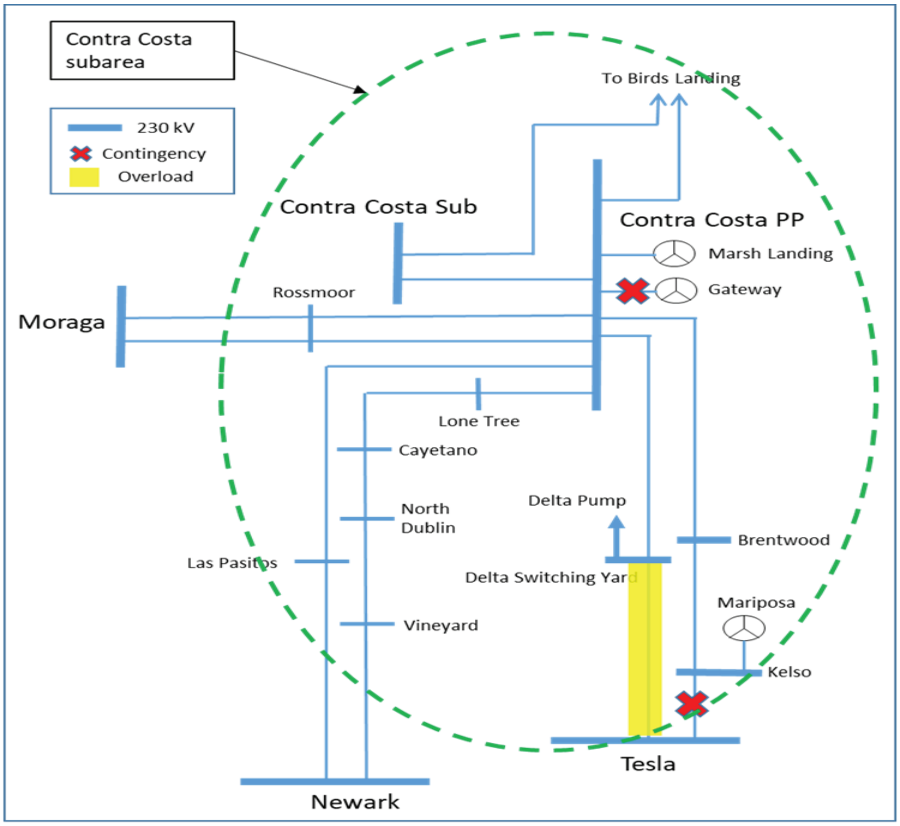
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 (T-165Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.5.7 *Contra Costa Sub-area*

Contra Costa is a Sub-area of the Greater Bay LCR Area.

3.2.5.7.1 Contra Costa LCR Sub-area Diagram

Figure 3.2-37 Contra Costa LCR Sub-area



3.2.5.7.2 Contra Costa LCR Sub-area Load and Resources

Table 3.2-34 provides the forecast load and resources in Contra Costa LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-34 Contra Costa LCR Sub-area 2025 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Contra Costa Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller, Battery, Solar	1669	1669
	MUNI	127	127
	QF	0	0
	Wind	244	244
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**2040**	**2040**

3.2.5.7.3 Contra Costa LCR Sub-area Hourly Profiles

The Contra Costa Sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

3.2.5.7.4 Contra Costa LCR Sub-area Requirement

Table 3.2-35 identifies the sub-area LCR requirements. The LCR requirement for the Category P6 contingency is 1417 MW.

Table 3.2-35 Contra Costa LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2025	First limit	P3	Delta Switching Yard-Tesla 230 kV	Kelso-Tesla 230 kV line and Gateway unit	1417

3.2.5.7.5 Effectiveness factors:

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

3.2.5.8 *Bay Area overall*

3.2.5.8.1 Bay Area LCR Area Hourly Profiles

Figure 3.2-38 illustrates the forecast 2025 profile for the peak day for the Bay Area LCR area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.2-39 illustrates the forecast 2025 hourly profile for Bay Area LCR area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-38 Bay Area LCR Area 2025 Peak Day Forecast Profiles

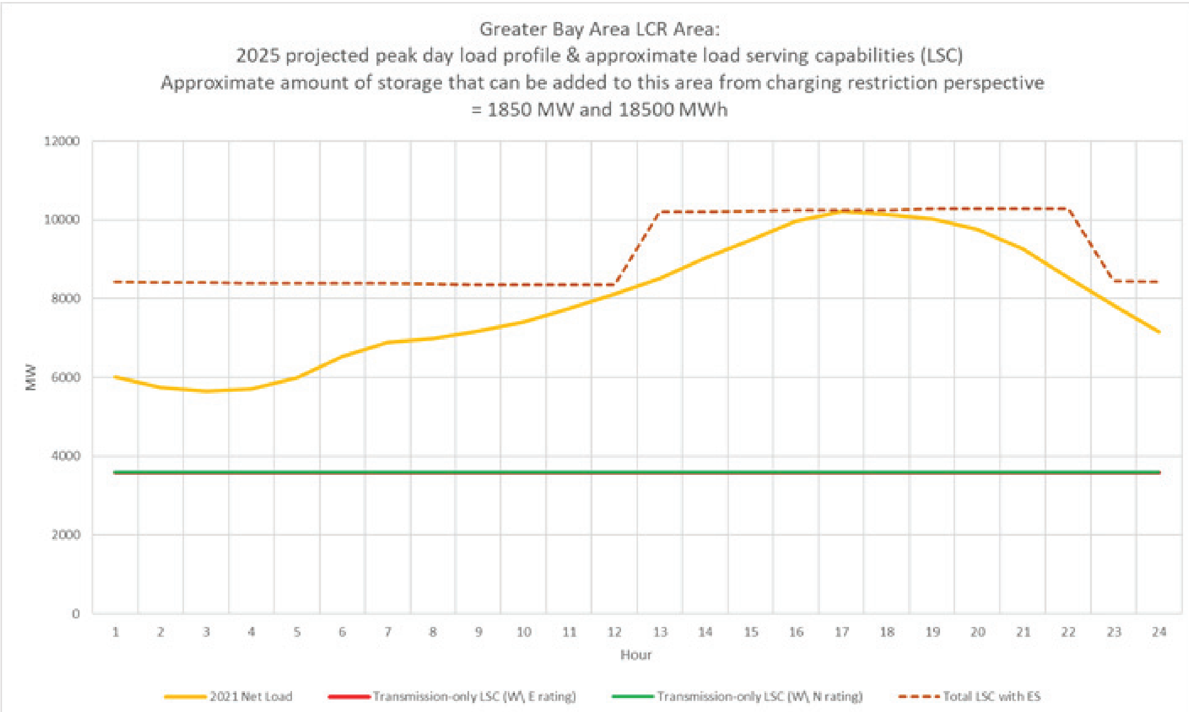
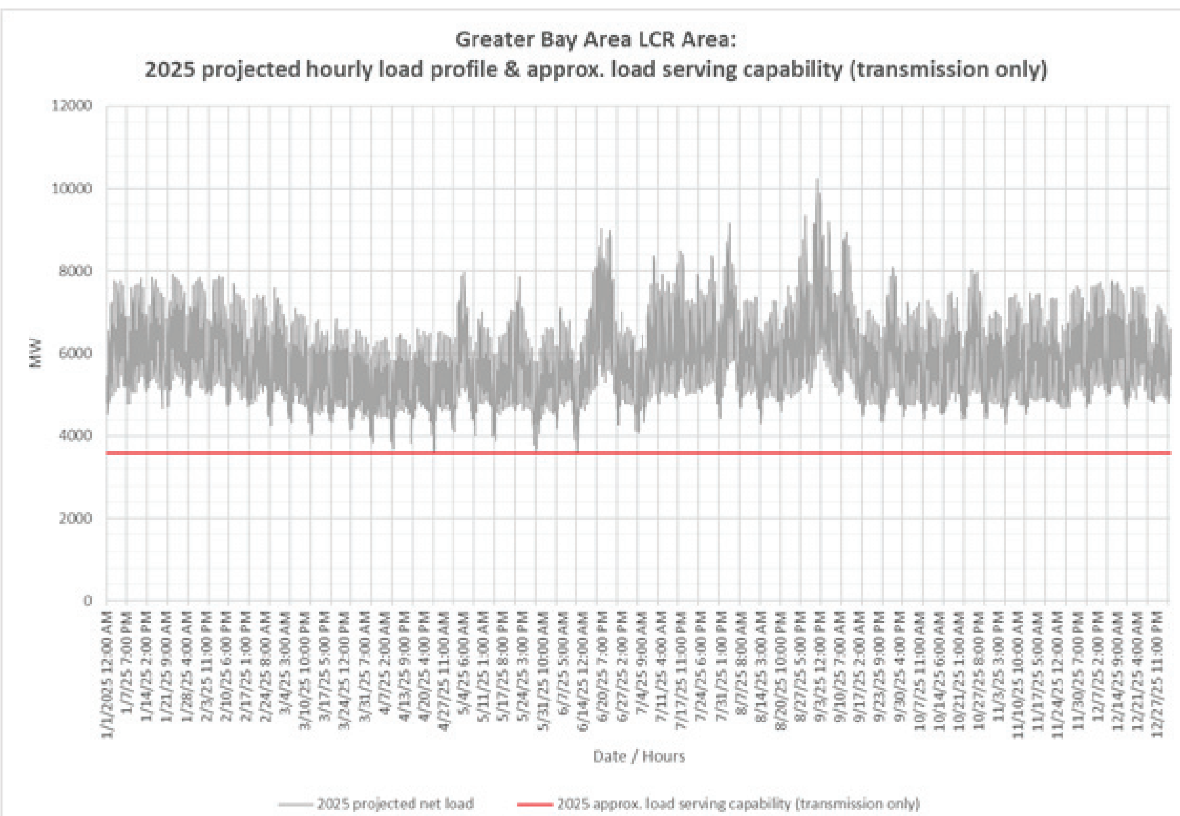


Figure 3.2-39 Bay Area LCR Area 2025 Forecast Hourly Profiles



3.2.5.8.2 Greater Bay LCR Area Overall Requirement

Table 3.2-36 identifies the area LCR requirements. The LCR requirement for the Category P6 contingency is 6110 MW.

Table 3.2-36 Bay Area LCR Overall area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2025	First limit	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	6110

3.2.5.8.3 Changes compared to 2024 requirements

Load forecast went up by 316 MW and total LCR need went up by 1715 MW mainly due to the new LCR criteria.

3.2.6 Greater Fresno Area

3.2.6.1 *Area Definition:*

The transmission facilities coming into the Greater Fresno area are:

Gates-Mustang #1 230 kV

Gates-Mustang #2 230 kV

Gates #5 230/70 kV Transformer Bank

Mercy Spring 230 /70 Bank # 1

Los Banos #3 230/70 Transformer Bank

Los Banos #4 230/70 Transformer Bank

Warnerville-Wilson 230kV

Melones-North Merced 230 kV line

Panoche-Tranquility #1 230 kV

Panoche-Tranquility #2 230 kV

Panoche #1 230/115 kV Transformer Bank

Panoche #2 230/115 kV Transformer Bank

Corcoran-Smyrna 115kV

Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

Gates is out Mustang is in

Gates is out Mustang is in

Gates 230 is out Gates 70 is in

Mercy Springs 230 is out Mercy Springs 70 is in

Los Banos 230 is out Los Banos 70 is in

Los Banos 230 is out Los Banos 70 is in

Warnerville is out Wilson is in

Melones is out North Merced is in

Panoche is out Tranquility #1 is in

Panoche is out Tranquility #2 is in

Panoche 230 is out Panoche 115 is in

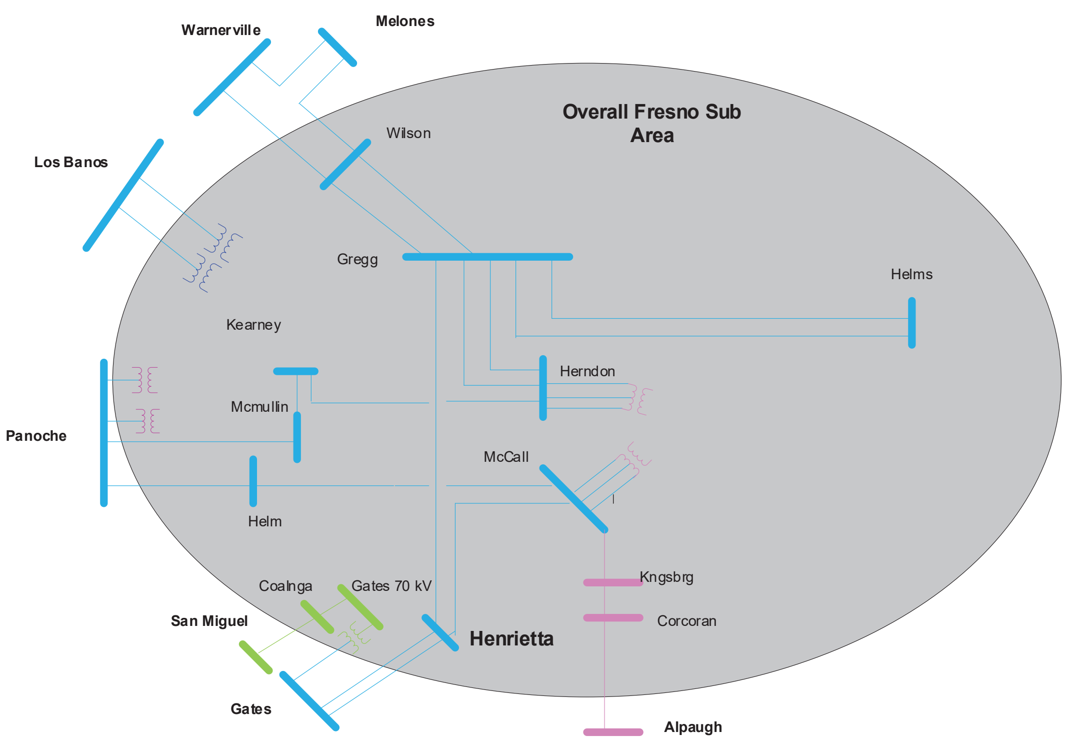
Panoche 230 is out Panoche 115 is in

Corcoran is in Smyrna is out

Coalinga is in San Miguel is out

3.2.6.1.2 Fresno LCR Area Diagram

Figure 3.2-40 Fresno LCR Area



3.2.6.1.3 Fresno LCR Area Load and Resources

Table 3.2-37 provides the forecast load and resources in Fresno LCR Area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 18:40 PM.

At the local area peak time the estimated, ISO metered, solar output is 12.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-37 Fresno LCR Area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	3217	Market, Net Seller, Battery	2815	2815
AAEE	-26	MUNI	212	212
Behind the meter DG	-5	QF	4	4
Net Load	**3186**	Solar	361	160
Transmission Losses	93	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**3279**	**Total**	**3392**	**3191**

3.2.6.1.4 Approved transmission projects modeled

Northern Fresno 115 kV Reinforcement (Revised scope – Mar 2021)

Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade (Jan 2021)

Wilson-Legrand 115 kV Reconductoring (Apr 2020)

Panoche-Oro Loma 115 kV Reconductoring (Apr 2021)

Oro Loma 70 kV Reinforcement (May 2020)

Reedley 70 kV Reinforcement Projects (Dec 2021)

Herndon-Bullard Reconductoring Projects (Jan 2021)

Wilson 115 kV Area Reinforcement (May 2023)

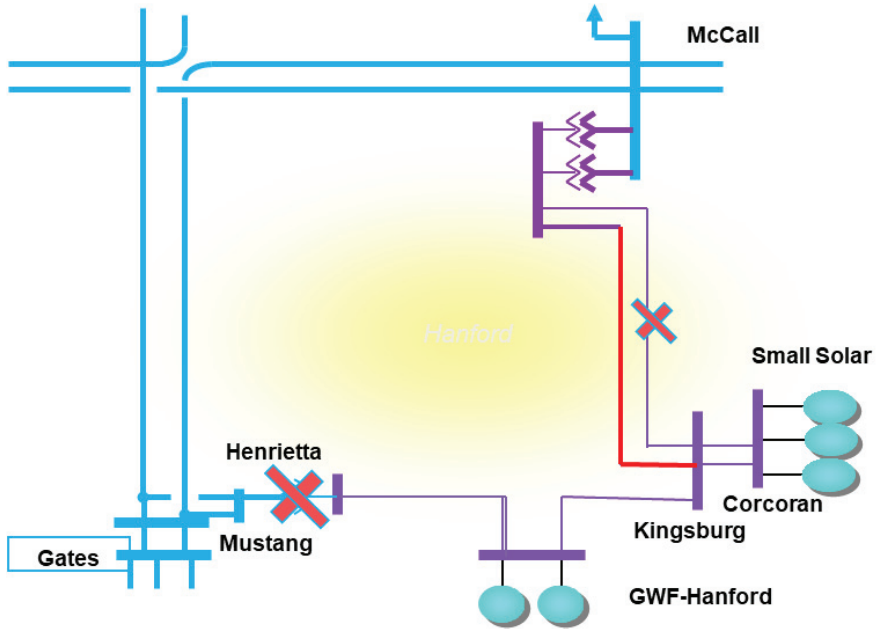
Bellota-Warnerville 230 kV Line Reconductoring (Dec 2023)

3.2.6.2 *Hanford Sub-area*

Hanford is a Sub-area of the Fresno LCR Area.

3.2.6.2.1 Hanford LCR Sub-area Diagram

Figure 3.2-41 Hanford LCR Sub-area



3.2.6.2.2 Hanford LCR Sub-area Load and Resources

Table 3.2-38 provides the forecast load and resources in Hanford LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-38 Hanford LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	209	Market, Net Seller, Battery	125	125
AAEE	-1	MUNI	0	0
Behind the meter DG	-3	QF	0	0
Net Load	**205**	Solar	25	11
Transmission Losses	5	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**210**	**Total**	**150**	**136**

3.2.6.2.3 Hanford LCR Sub-area Hourly Profiles

Figure 3.2-42 illustrates the forecast 2025 profile for the peak day for the Hanford LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-43 illustrates the forecast 2025 hourly profile for Hanford LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-42 Hanford LCR Sub-area 2025 Peak Day Forecast Profiles

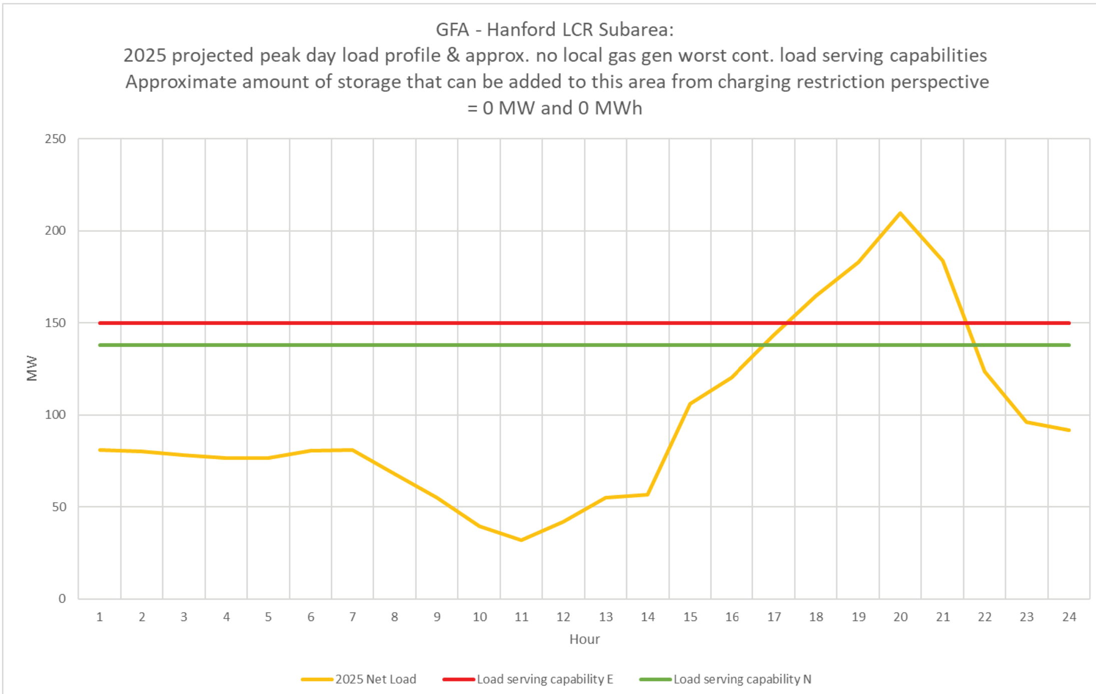
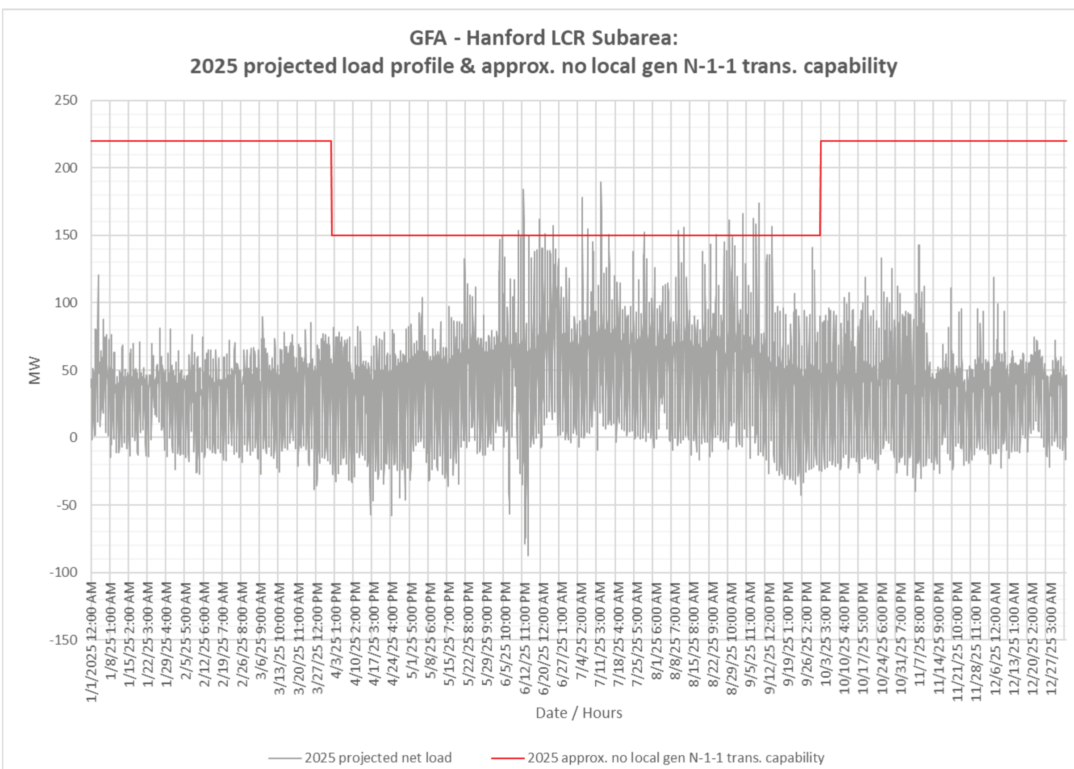


Figure 3.2-43 Hanford LCR Sub-area 2025 Forecast Hourly Profiles



3.2.6.2.4 Hanford LCR Sub-area Requirement

Table 3.2-39 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 58 MW.

Table 3.2-39 Hanford LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	McCall-Kingsburg #2 115 kV	McCall-Kingsburg #1 115kV line and Henrietta 230/115kV TB#3	58

3.2.6.2.5 **Effectiveness factors:**

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

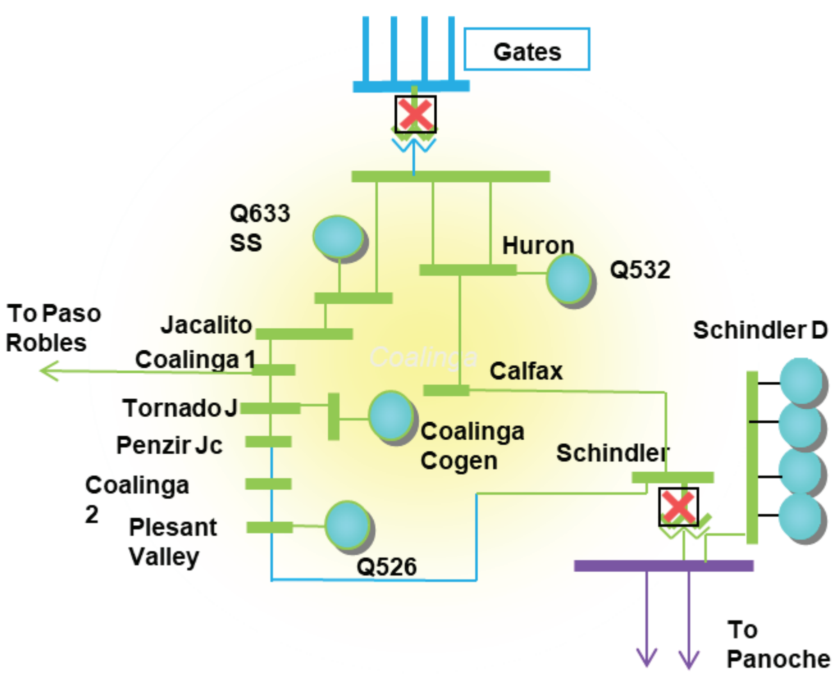
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.6.3 *Coalinga Sub-area*

Coalinga is a Sub-area of the Fresno LCR Area.

3.2.6.3.1 Coalinga LCR Sub-area Diagram

Figure 3.2-44 Coalinga LCR Sub-area



3.2.6.3.2 Coalinga LCR Sub-area Load and Resources

Table 3.2-40 provides the forecast load and resources in Coalinga LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-40 Coalinga LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	89	Market, Net Seller, Battery	0	0
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	3	3
Net Load	**88**	Solar	13	6
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**89**	**Total**	**16**	**9**

3.2.6.3.3 Coalinga LCR Sub-area Hourly Profiles

Figure 3.2-45 illustrates the forecast 2025 profile for the peak day for the Coalinga LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-46 illustrates the forecast 2025 hourly profile for Coalinga LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-45 Coalinga LCR Sub-area 2025 Peak Day Forecast Profiles

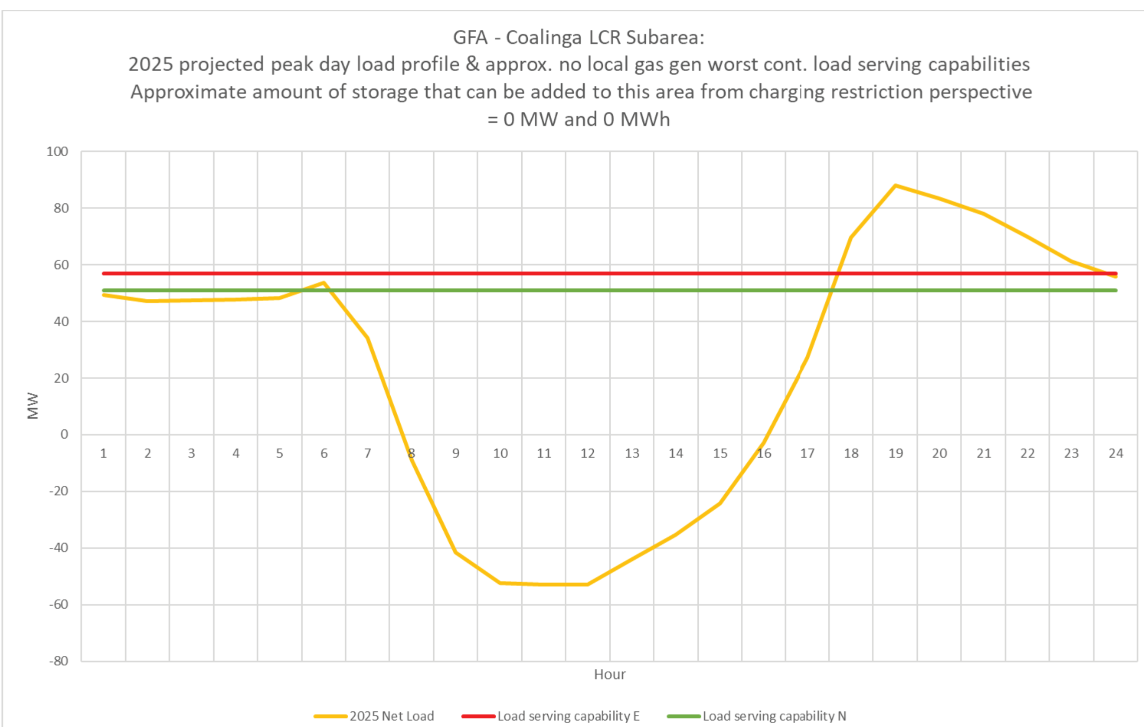
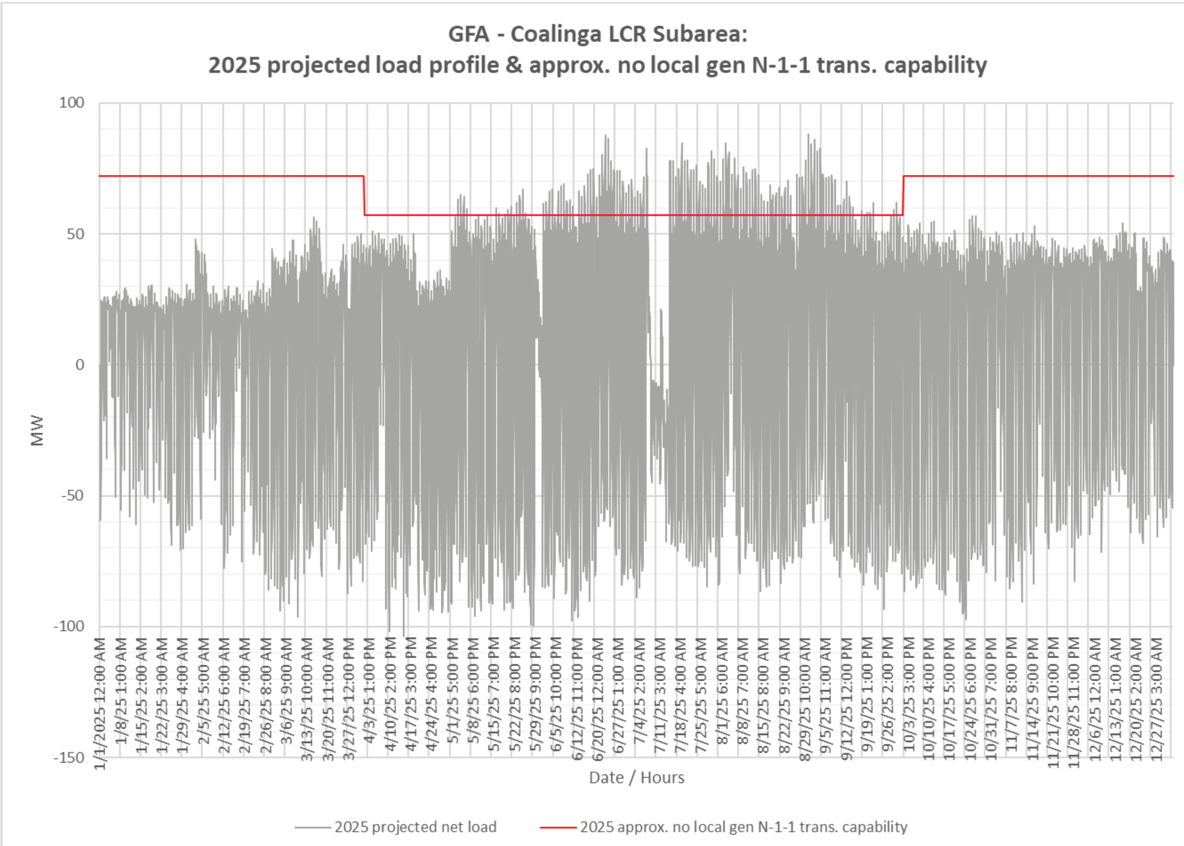


Figure 3.2-46 Coalinga LCR Sub-area 2025 Forecast Hourly Profiles



3.2.6.3.4 Coalinga LCR Sub-area Requirement

Table 3.2-41 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 52 MW including a 43 MW at peak deficiency and 36 MW NQC deficiency.

Table 3.2-41 Coalinga LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Overload on San-Miguel-Coalinga 70kV Line and Voltage Instability	T-1/T-1: Gates 230/70kV TB #5 and Schindler 115/70 kV TB#1	52 (43 Peak) (36 NQC)

3.2.6.3.5 **Effectiveness factors:**

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

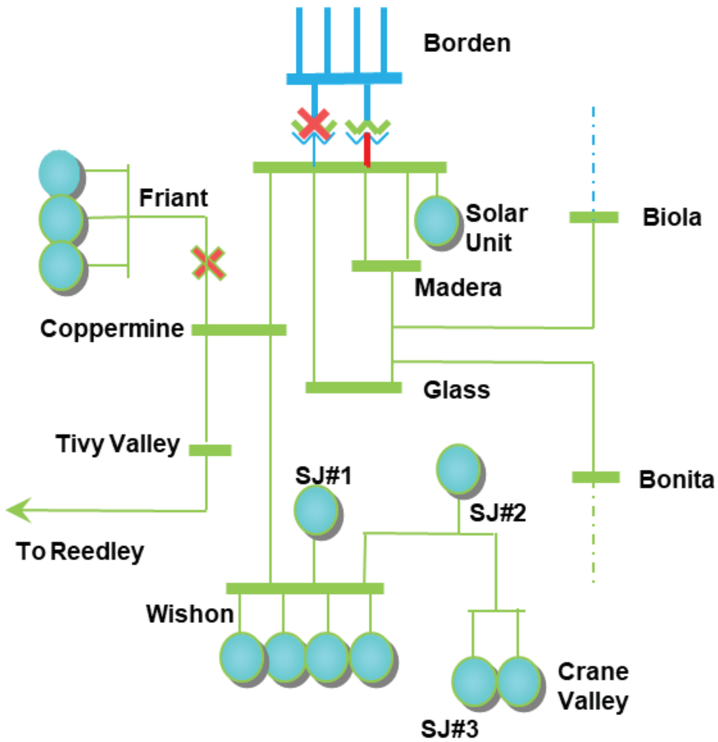
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.6.4 ***Borden Sub-area***

Borden is a sub-area of the Fresno LCR Area.

3.2.6.4.1 Borden LCR Sub-area Diagram

Figure 3.2-47 Borden LCR Sub-area



3.2.6.4.2 Borden LCR Sub-area Load and Resources

Table 3.2-42 provides the forecast load and resources in Borden LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-42 Borden LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	136	Market, Net Seller, Battery	33	33
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**135**	Solar	13	6
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**137**	**Total**	**46**	**39**

3.2.6.4.3 Borden LCR Sub-area Hourly Profiles

Figure 3.2-48 illustrates the forecast 2025 profile for the peak day for the Borden LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-49 illustrates the forecast 2025 hourly profile for Borden LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-48 Borden LCR Sub-area 2025 Peak Day Forecast Profiles

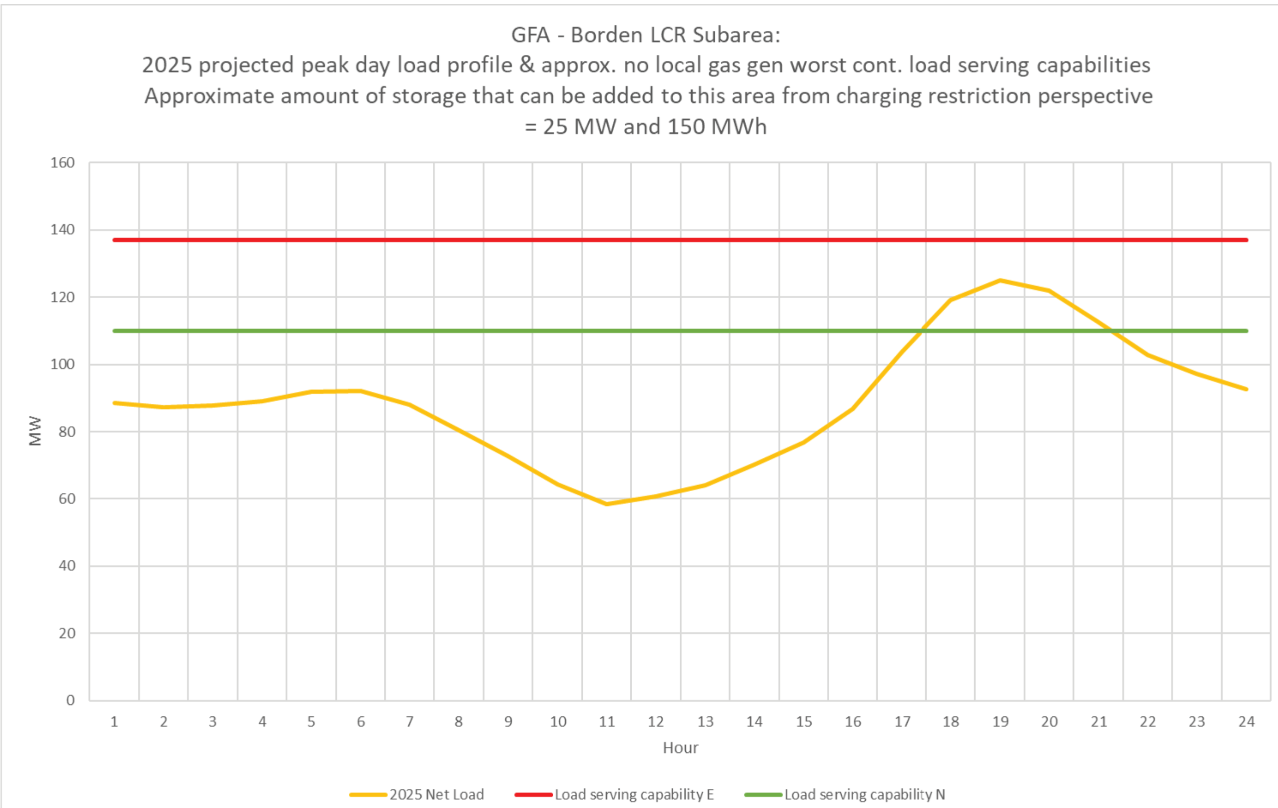
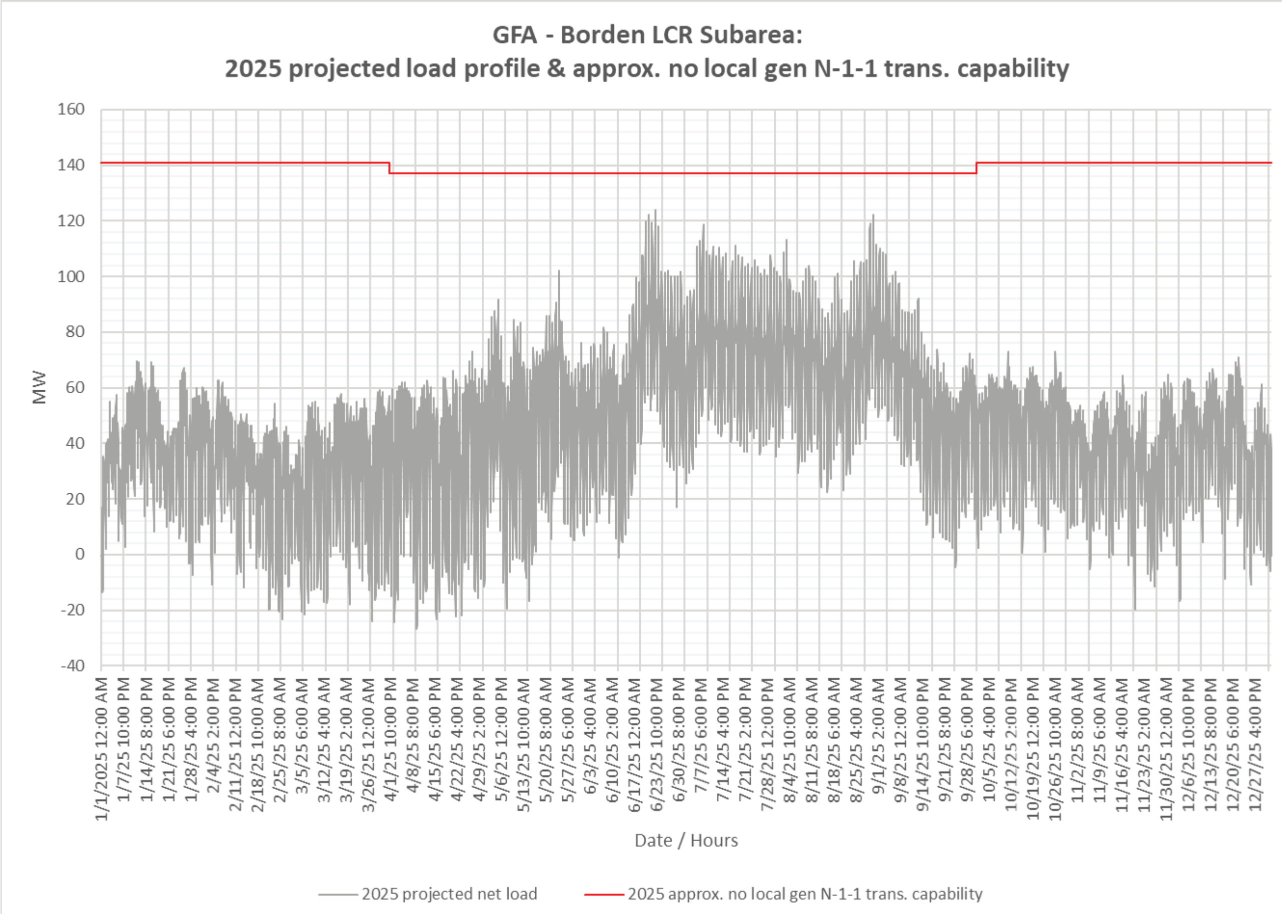


Figure 3.2-49 Borden LCR Sub-area 2025 Forecast Hourly Profiles



3.2.6.4.4 Borden LCR Sub-area Requirement

Table 3.2-43 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 4 MW.

Table 3.2-43 Borden LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Borden #1 230/70 kV Tx	Friant - Coppermine 70 kV & Borden #2 230/70 kV Tx	4

3.2.6.4.5 **Effectiveness factors:**

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

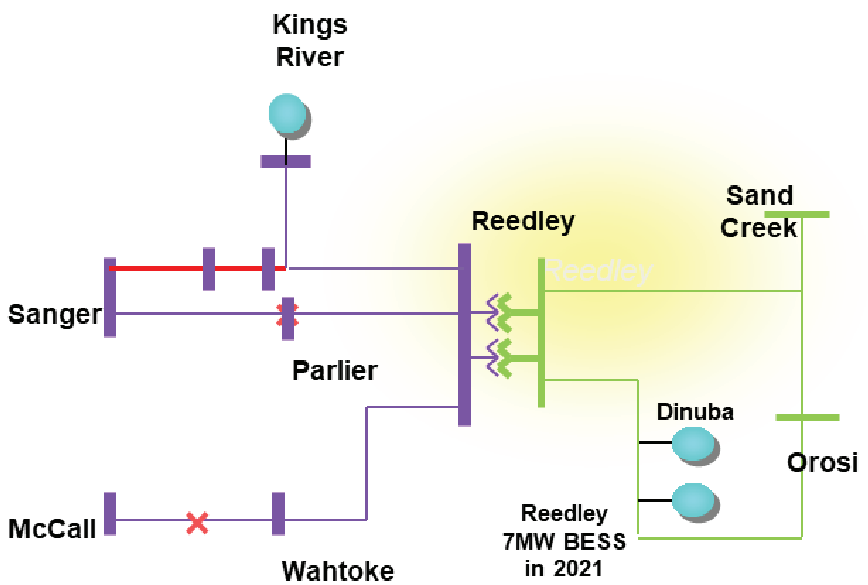
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.6.5 *Reedley Sub-area*

Reedley is a Sub-area of the Fresno LCR Area.

3.2.6.5.1 Reedley LCR Sub-area Diagram

Figure 3.2-50 Reedley LCR Sub-area



3.2.6.5.2 Reedley LCR Sub-area Load and Resources

Table 3.2-44 provides the forecast load and resources in Reedley LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-44 Reedley LCR Sub-area 2024 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	223	Market	51	51
AAEE	-8	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**215**	LTPP Preferred Resources	0	0
Transmission Losses	50	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**265**	**Total**	**51**	**51**

3.2.6.5.3 Reedley LCR Sub-area Hourly Profiles

Figure 3.2-51 illustrates the forecast 2025 profile for the peak day for the Reedley LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-52 illustrates the forecast 2025 hourly profile for Reedley LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-51 Reedley LCR Sub-area 2025 Peak Day Forecast Profiles

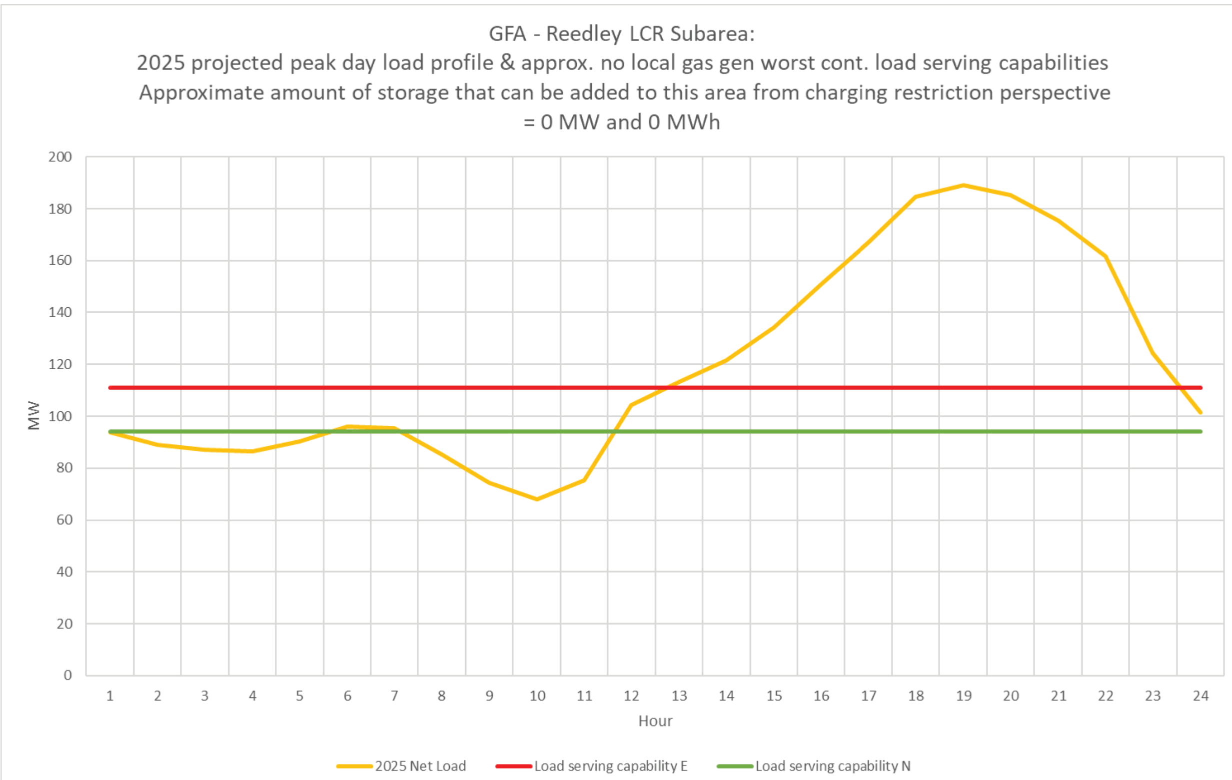
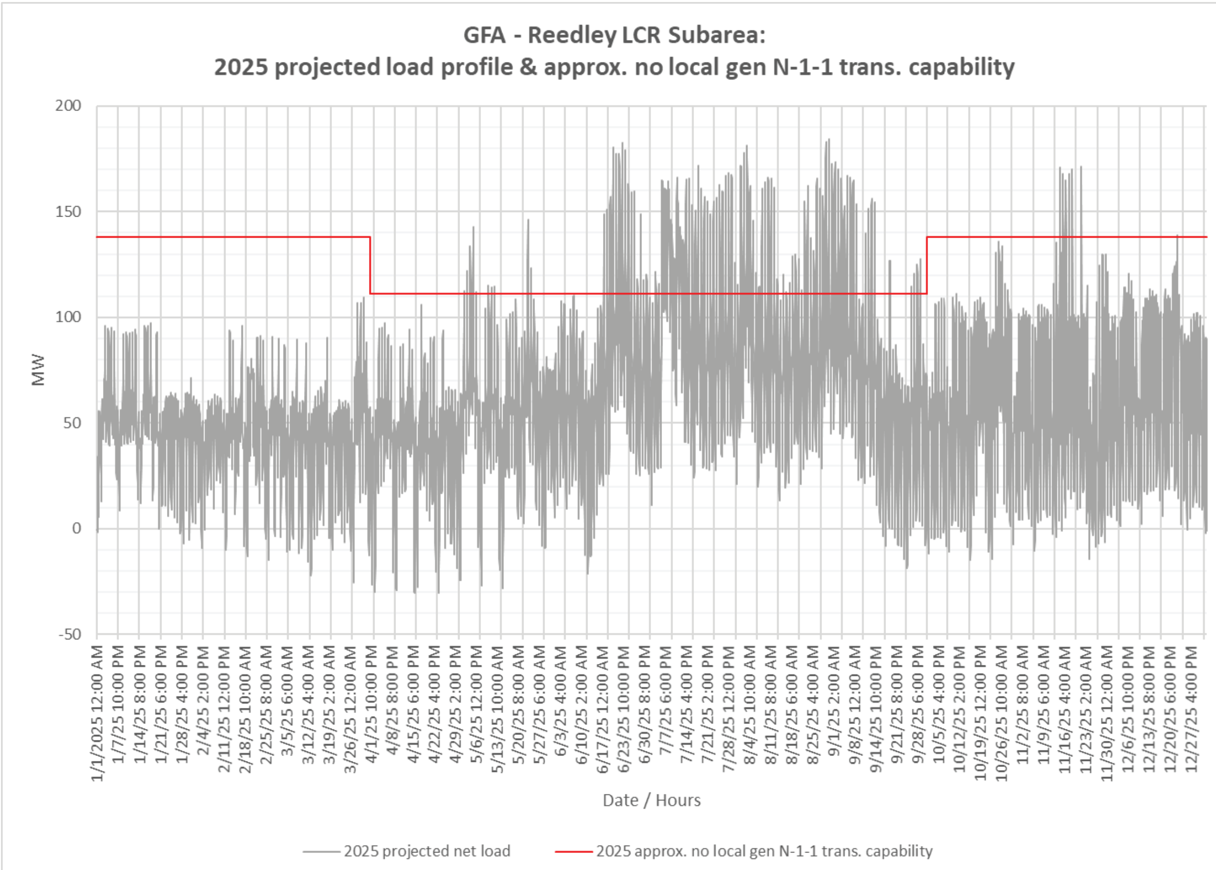


Figure 3.2-52 Reedley LCR Sub-area 2025 Forecast Hourly Profiles



3.2.6.5.4 Reedley LCR Sub-area Requirement

Table 3.2-45 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 84 MW including a 33 MW of deficiency.

Table 3.2-45 Reedley LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Kings River-Sanger-Reedley 115 kV	McCall-Reedley 115 kV & Sanger-Reedley 115 kV	84 (33)

3.2.6.5.5 **Effectiveness factors:**

All units within the Reedley Sub-area have the same effectiveness factor.

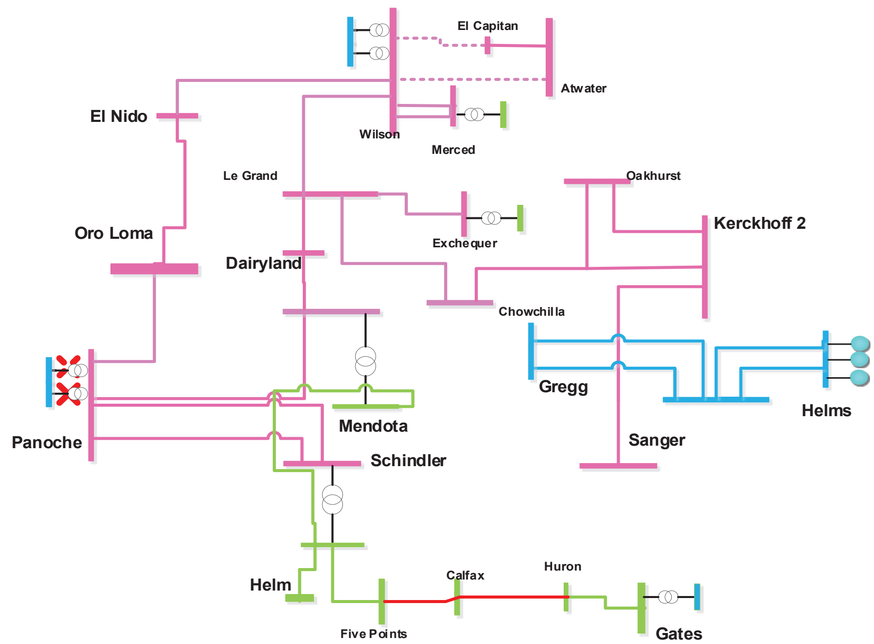
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.6.6 *Panoche Sub-area*

Panoche is a Sub-area of the Fresno LCR Area.

3.2.6.6.1 Panoche LCR Sub-area Diagram

Figure 3.2-53 Panoche LCR Sub-area



3.2.6.6.2 Panoche LCR Sub-area Load and Resources

Table 3.2-46 provides the forecast load and resources in Panoche LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-46 Panoche LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	427	Market, Net Seller	282	282
AAEE	-4	MUNI	100	100
Behind the meter DG	-1	QF	3	3
Net Load	**422**	Solar	89	40
Transmission Losses	8	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**430**	**Total**	**474**	**425**

3.2.6.6.3 Panoche LCR Sub-area Hourly Profiles

Figure 3.2-54 illustrates the forecast 2025 profile for the peak day for the Panoche LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-55 illustrates the forecast 2025 hourly profile for Panoche LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-54 Panoche LCR Sub-area 2025 Peak Day Forecast Profiles

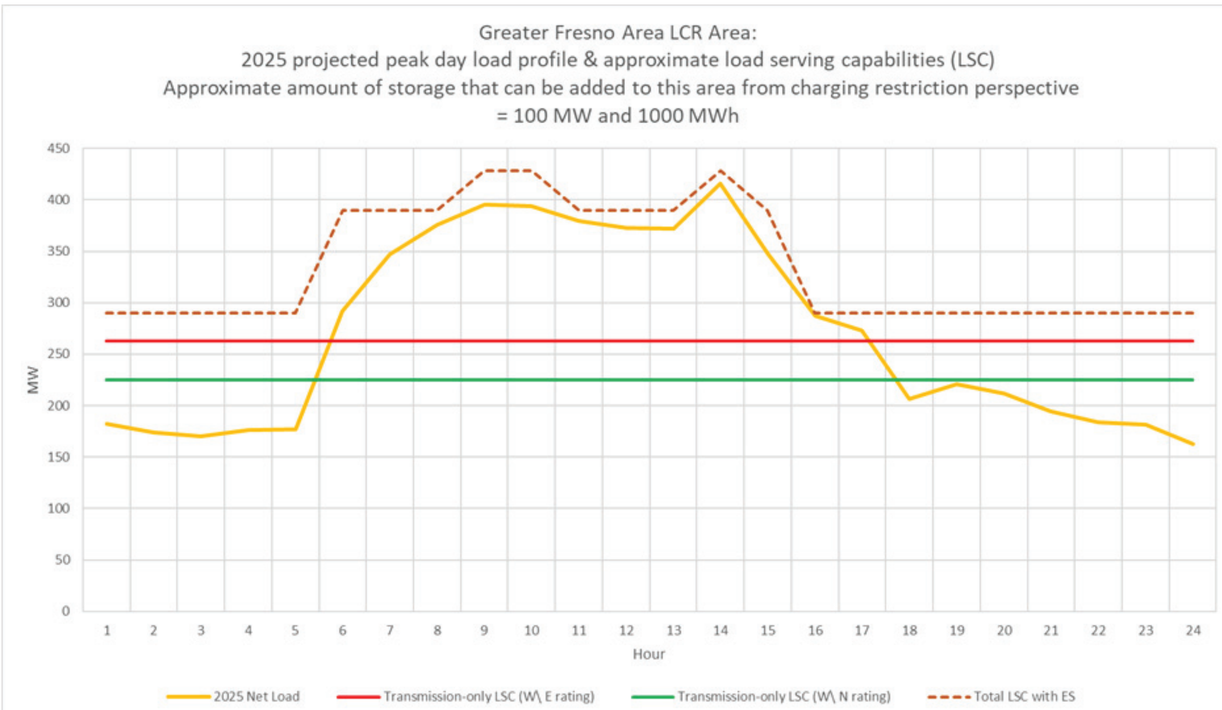
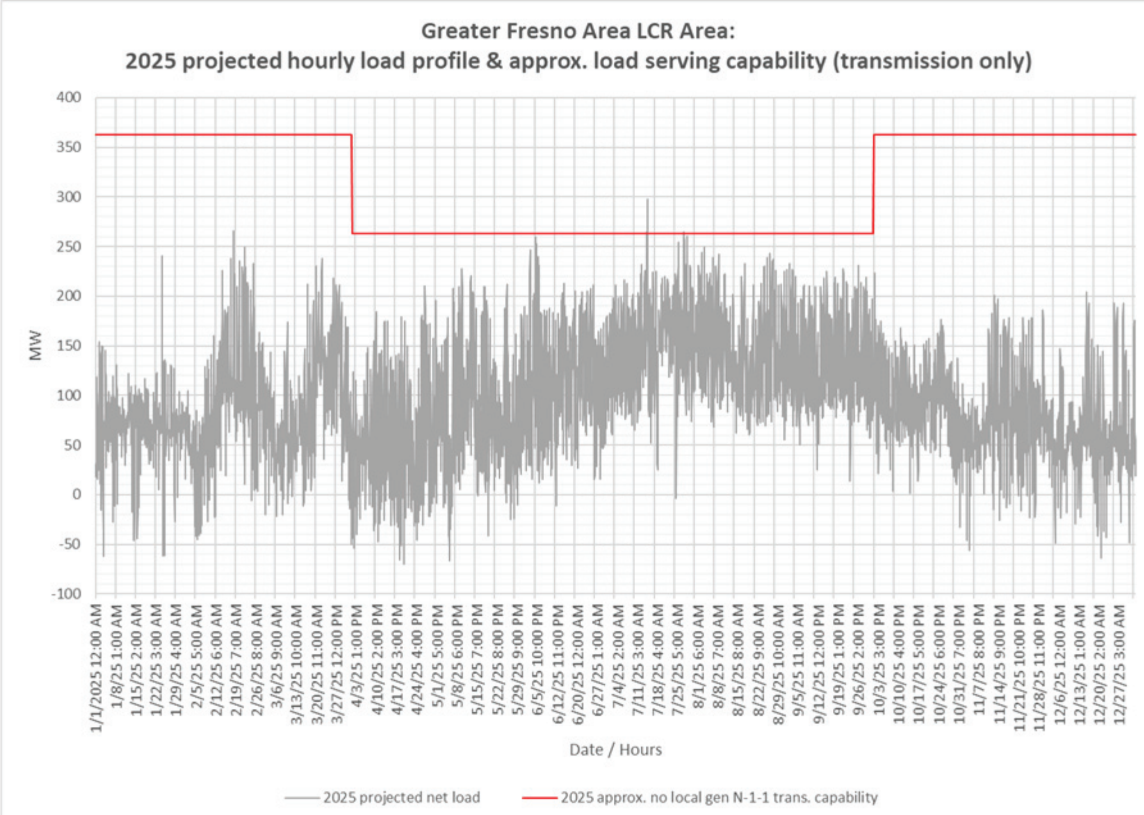


Figure 3.2-55 Panoche LCR Sub-area 2025 Forecast Hourly Profiles



3.2.6.6.4 Panoche LCR Sub-area Requirement

Table 3.2-47 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 164 MW.

Table 3.2-47 Panoche LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P6	Five Points-Huron-Gates 70 kV line	Panoche 230/115 kV TB #2 and Panoche 230/115 kV TB #	164

3.2.6.6.5 **Effectiveness factors:**

Effective factors for generators in the Panoche LCR sub-area are in Attachment B table title Panoche.

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

3.2.6.7 *Wilson 115 kV Sub-area*

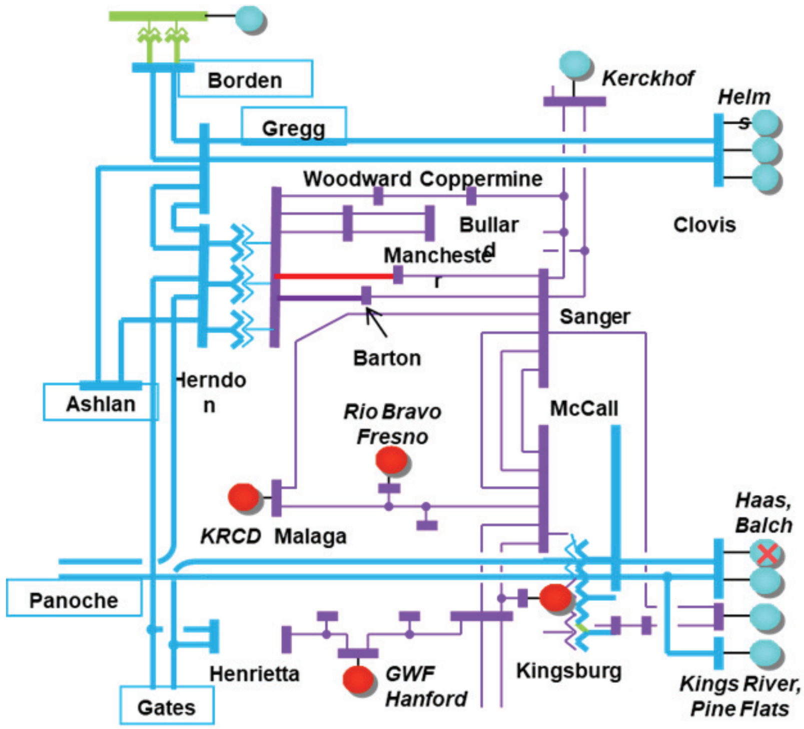
Wilson 115 kV sub-area will be eliminated due to the Wilson #3 230/115 kV transformer coming into service as part of the Wilson 115 kV area reinforcement transmission project.

3.2.6.8 *Herndon Sub-area*

Herndon is a Sub-area of the Fresno LCR Area.

3.2.6.8.1 Herndon LCR Sub-area Diagram

Figure 3.2-56 Herndon LCR Sub-area



3.2.6.8.2 Herndon LCR Sub-area Load and Resources

Table 3.2-48 provides the forecast load and resources in Herndon LCR sub-area in 2024. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-48 Herndon LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1523	Market, Net Seller, Battery	997	997
AAEE	-13	MUNI	98	98
Behind the meter DG	-3	QF	1	1
Net Load	**1507**	Solar	63	28

Transmission Losses	25	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1532**	**Total**	**1159**	**1124**

3.2.6.8.3 Herndon LCR Sub-area Hourly Profiles

Figure 3.2-57 illustrates the forecast 2025 profile for the peak day for the Herndon LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-58 illustrates the forecast 2025 hourly profile for Herndon LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-57 Herndon LCR Sub-area 2025 Peak Day Forecast Profiles

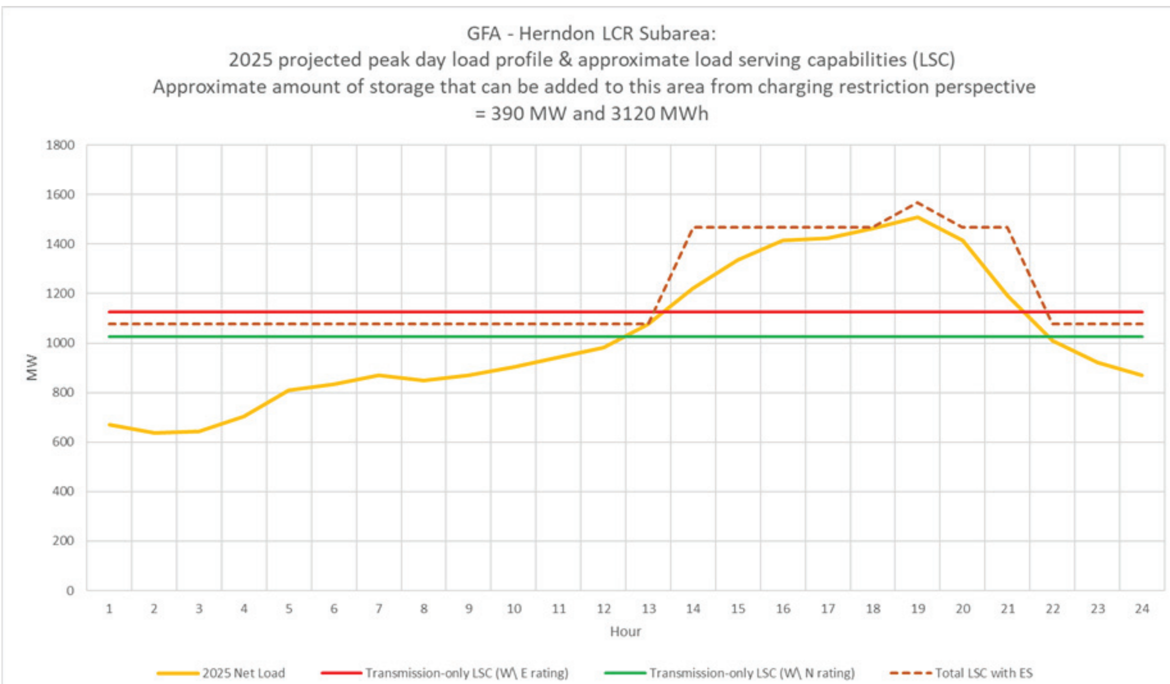
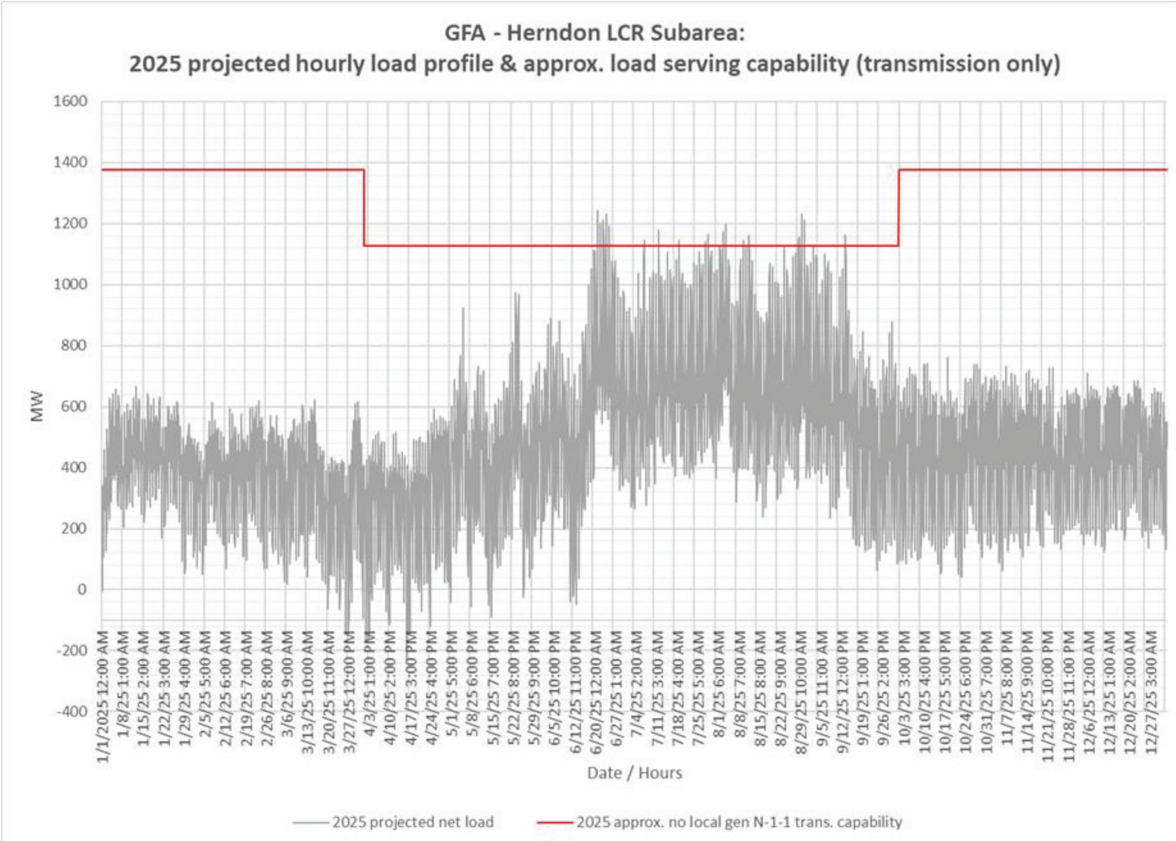


Figure 3.2-58 Herndon LCR Sub-area 2025 Forecast Hourly Profiles



3.2.6.8.4 Herndon LCR Sub-area Requirement

Table 3.2-49 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 441 MW.

Table 3.2-49 Herndon LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P6	Herndon-Manchester 115 kV	Herndon-Woodward 115 kV line & Herndon-Barton 115 kV line	441

3.2.6.8.5 **Effectiveness factors:**

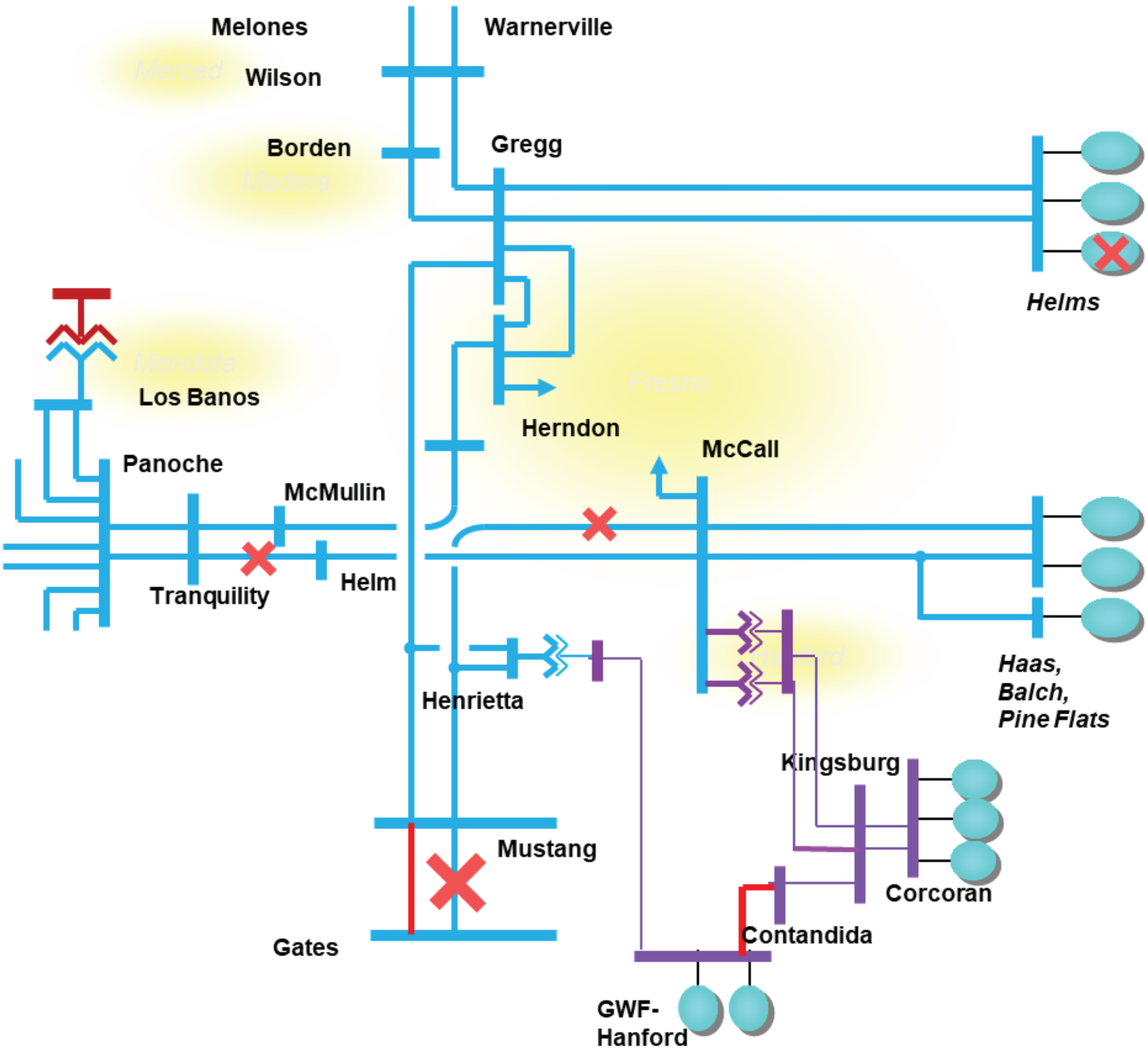
Effectiveness factors for generators in the Herndon LCR sub-area are in Attachment B table titled Herndon.

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

3.2.6.9 *Fresno Overall area*

3.2.6.9.1 Fresno LCR area Diagram

Figure 3.2-59 Fresno LCR area



3.2.6.9.2 Fresno Overall LCR area Load and Resources

Table 3.2-37 provides the forecast load and resources in Fresno LCR area in 2025. The list of generators within the LCR area are provided in Attachment A.

3.2.6.9.3 Fresno Overall LCR area Hourly Profiles

Figure 3.2-60 illustrates the forecast 2025 profile for the peak day for the Overall LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.2-61 illustrates the forecast 2025 hourly profile for Overall LCR sub-area with the Category P6 emergency load serving capability without local gas resources.

Figure 3.2-60 Fresno LCR Area 2025 Peak Day Forecast Profiles

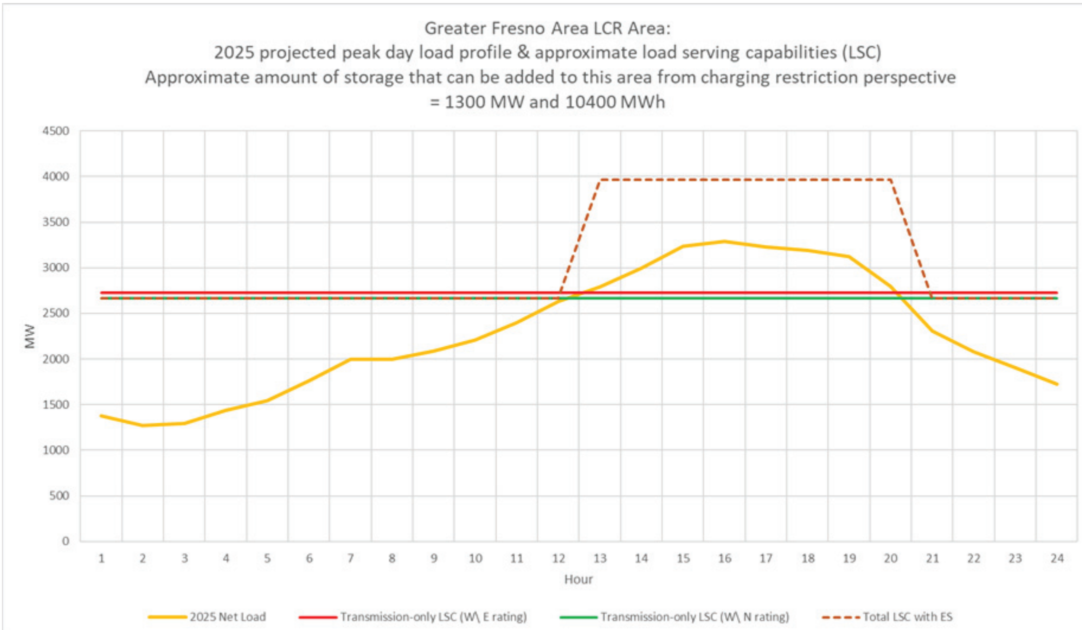
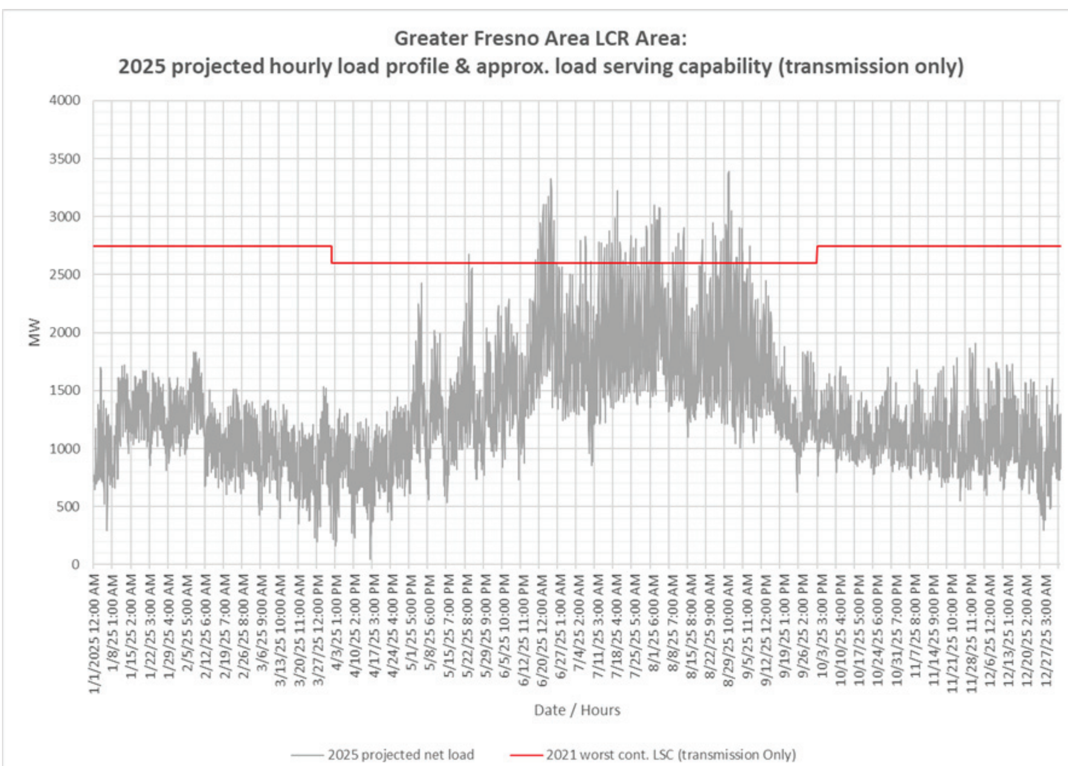


Figure 3.2-61 Fresno LCR Area 2025 Forecast Hourly Profiles



3.2.6.9.4 Fresno Overall LCR Area Requirement

Table 3.2-50 identifies the area LCR requirements. The LCR requirement Category P6 contingency is 1971 MW.

Table 3.2-50 Fresno Overall LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First limit	P6	GWF-Contandida 115 kV Line	Panoche-Helm 230 kV Line and Gates-McCall 230 kV line	1971

3.2.6.9.5 **Effectiveness factors:**

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

3.2.6.9.6 Changes compared to 2024 requirements

Compared with 2024 the load forecast decreased by 58 MW and the LCR has increased by 260 MW, due to newly identified contingency and limiting element.

3.2.7 Kern Area

3.2.7.1 *Area Definition:*

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

Midway-Kern PP #1 230 kV Line

Midway-Kern PP #2 230 kV Line

Midway-Kern PP #3 230 kV Line

Midway-Kern PP #4 230 kV Line

Midway-WheelerRidge 230 kV # 1

Midway-WheelerRidge 230 kV # 2

Famoso-Lerdo 115 kV Line (Normal Open)

Wasco-Famoso 70 kV Line (Normal Open)

Copus-Old River 70 kV Line (Normal Open)

Copus-Old River 70 kV Line (Normal Open)

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

Midway 230 kV is out and Bakersfield 230 kV is in

Midway 230 kV is out and Stockdale 230 kV is in

Midway 230 kV is out Kern PP 230 kV is in

Midway 230 kV is out and Buena Vista 230 kV is in

Famoso 115 kV is out Cawelo 115 kV is in

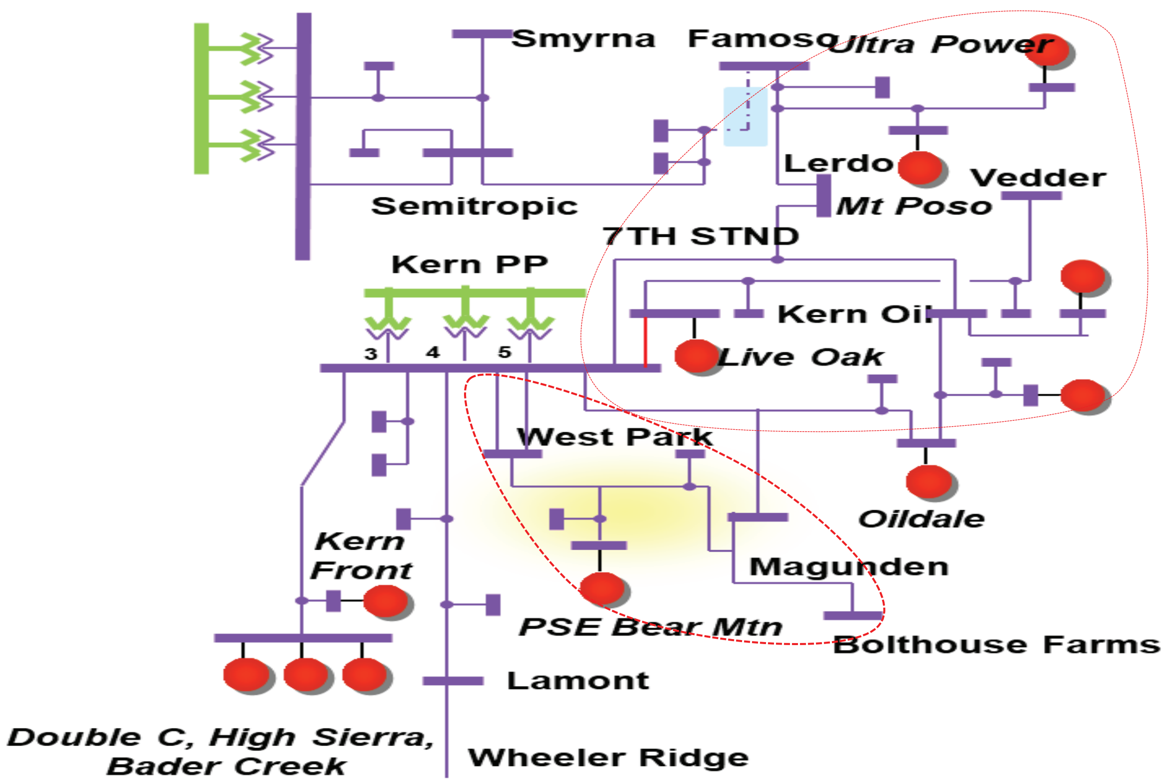
Wasco 70 kV is out Mc Farland 70 kV is in

Copus 70 kV is out, South Kern Solar 70 kV is in

Lakeview 70 kV is out, San Emidio Junction 70 kV is in

3.2.7.1.1 Kern LCR Area Diagram

Figure 3.2-62 Kern LCR Area



3.2.7.1.2 Kern LCR Area Load and Resources

Table 3.2-51 provides the forecast load and resources in Kern LCR area in 2025. The list of generators within the LCR area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 19:20 PM.

At the local area peak time the estimated, ISO metered, solar output is 0.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-51 Kern LCR Area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	1327[9]	Market, Net Seller	330	330
AAEE	-11	MUNI	0	0
Behind the meter DG	0	QF	5	5
Net Load	**1316**	Solar	78	0
Transmission Losses	15	Existing 20-minute Demand Response	0	0
Pumps	320	Mothballed	0	0
Load + Losses + Pumps	**1651**	**Total**	**413**	**335**

3.2.7.1.3 Approved transmission projects modeled

Kern PP 230 kV Area Reinforcement

Bakersfield Nos. 1 and 2 230 kV Tap Lines Reconductoring

Midway-Kern PP 230 kV #2 Line

Midway-Kern PP 1, 3 & 4 230 kV Line Capacity Increase

Kern PP 115 kV Area Reinforcement

Wheeler Ridge Junction Station

3.2.7.2 *Kern 70 kV Sub-area*

Kern 70 kV is a sub-area of the Kern LCR Area.

[9] Kern Area LCR definition has changed due to modeling of approved transmission upgrades

3.2.7.2.1 Kern 70 kV LCR Sub-area Diagram

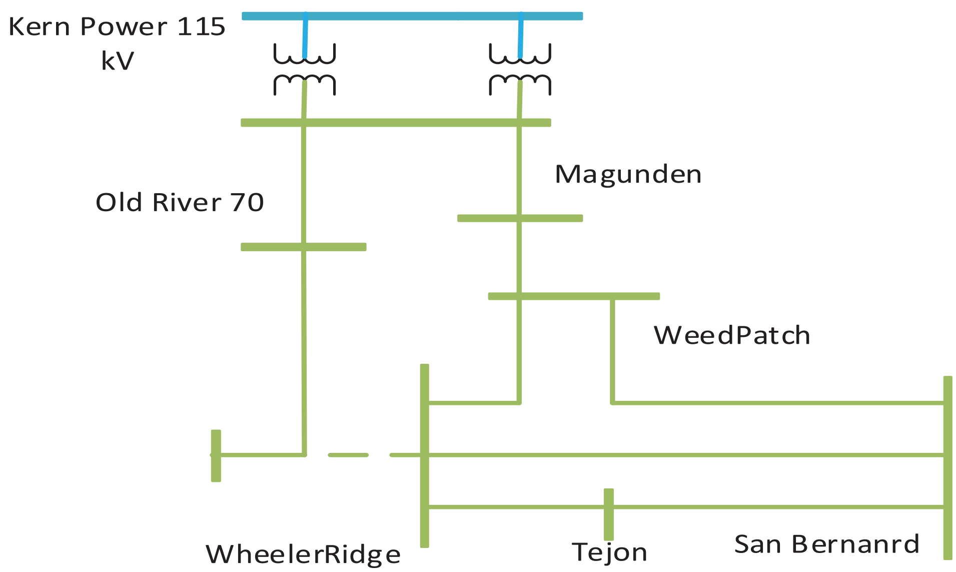


Figure 3.2-63 Kern 70 kV LCR Sub-area

3.2.7.2.2 Kern 70 kV LCR Sub-area Load and Resources

Table 3.2-52 provides the forecast load and resources in Kern 70 kV LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-52 Kern 70 kV LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	242	Market, Net Seller	4	4
AAEE	-2	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**240**	Solar	13	0
Transmission Losses	3	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**243**	**Total**	**17**	**4**

3.2.7.2.3 Kern 70 kV LCR Sub-area Hourly Profiles

Figure 3.2-64 illustrates the forecast 2025 profile for the summer peak, winter peak and spring off-peak days for the Kern 70 kV LCR sub-area with the Category P6 contingency transmission capability without resources. Figure 3.2-65 illustrates the forecast 2020 hourly profile for Kern 70 kV LCR sub-area with the Category P6 contingency transmission capability without resources.

Figure 3.2-64 Kern 70 kV LCR Sub-area 2025 Peak Day Forecast Profiles

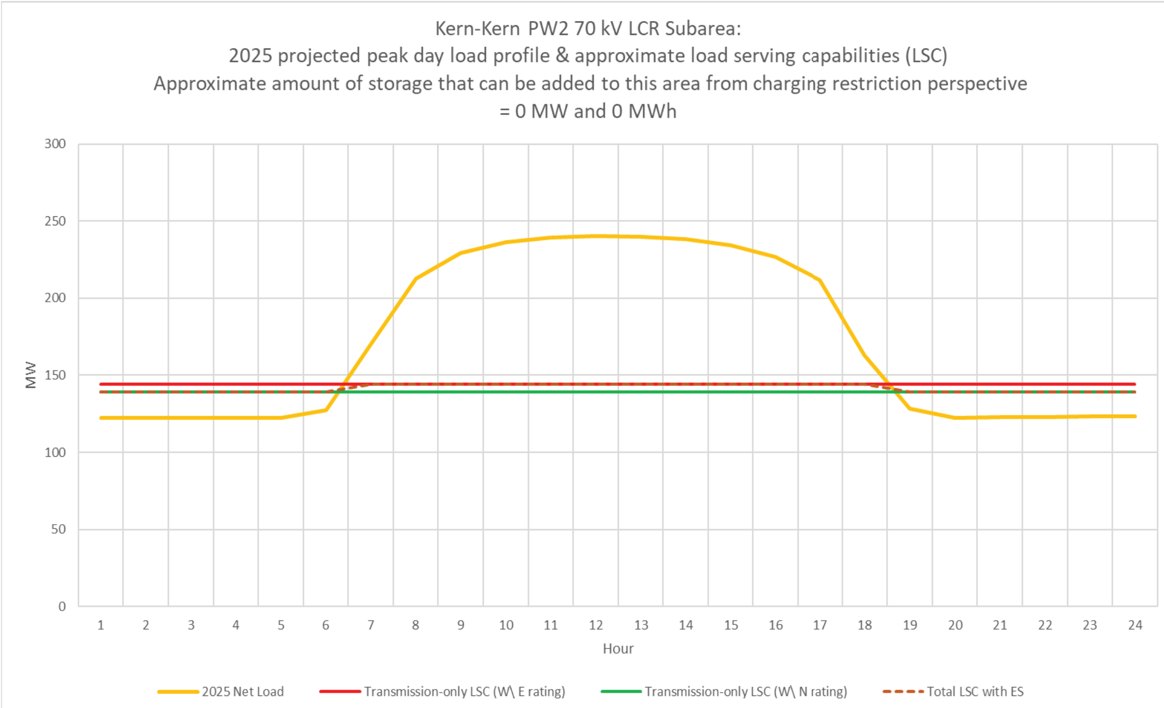
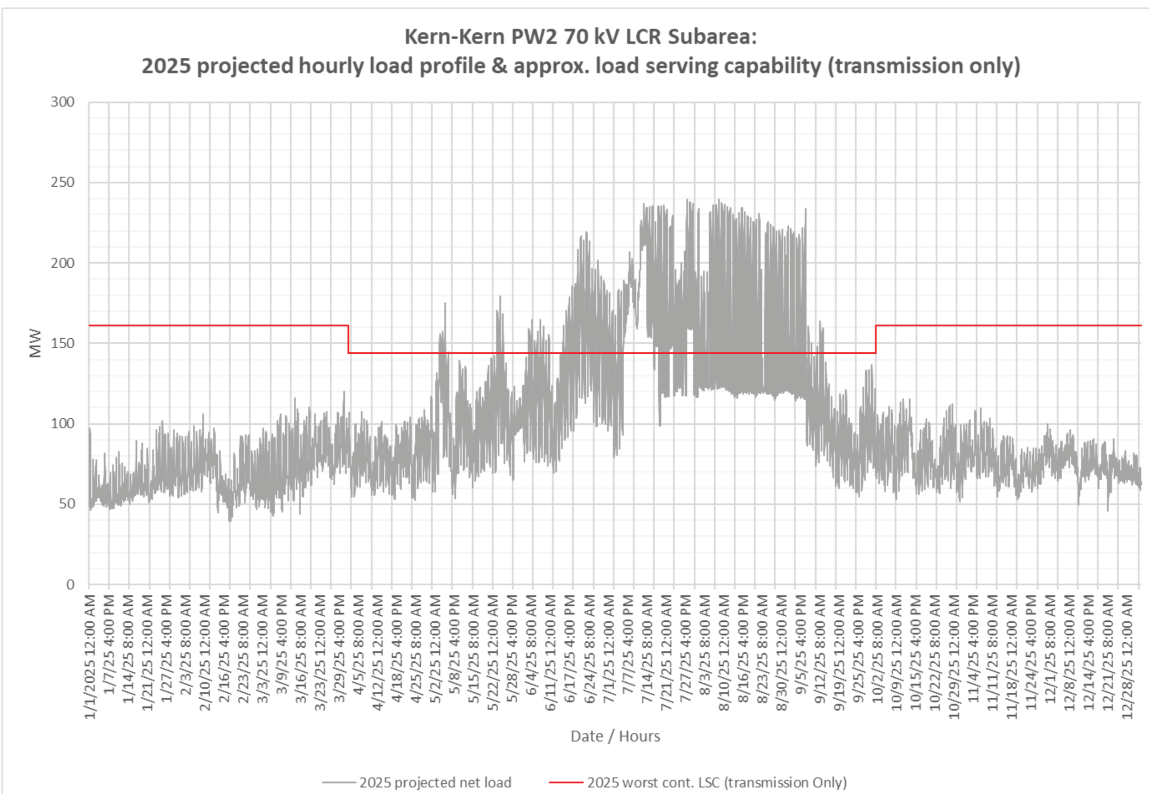


Figure 3.2-65 Kern 70 kV LCR Sub-area 2025 Forecast Hourly Profiles



3.2.7.2.4 Kern 70 kV LCR Sub-area Requirement

Table 3.2-53 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 90 MW including a 73 MW NQC deficiency or 86 MW at peak deficiency.

Table 3.2-53 Kern 70 kV LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Weedpatch to Weedpatch SF 70 kV	Kern PW1 115/70 T/F & Kern PW2 115/70 T/F	90 (73 NQC/86 Peak)

3.2.7.2.5 **Effectiveness factors:**

All units within the Kern 70 kV sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.7.3 ***Westpark Sub-area***

Westpark is a Sub-area of the Kern LCR Area.

3.2.7.3.1 Westpark LCR Sub-area Diagram

Please see Figure 3.2-62 for Westpark Sub-area diagram.

3.2.7.3.2 Westpark LCR Sub-area Load and Resources

Table 3.2-54 provides the forecast load and resources in Westpark LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-54 Westpark LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	165	Market, Net Seller	44	44
AAEE	-2	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**163**	LTPP Preferred Resources	0	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**164**	**Total**	**44**	**44**

3.2.7.3.3 Westpark LCR Sub-area Hourly Profiles

Figure 3.2-66 illustrates the forecast 2025 profile for the summer peak, winter peak and spring off-peak days for the Westpark LCR sub-area with the Category P6 contingency transmission capability without resources. Figure 3.2-67 illustrates the forecast 2025 hourly profile for Westpark LCR sub-area with the Category P6 contingency transmission capability without resources.

Figure 3.2-66 Westpark LCR Sub-area 2025 Peak Day Forecast Profiles

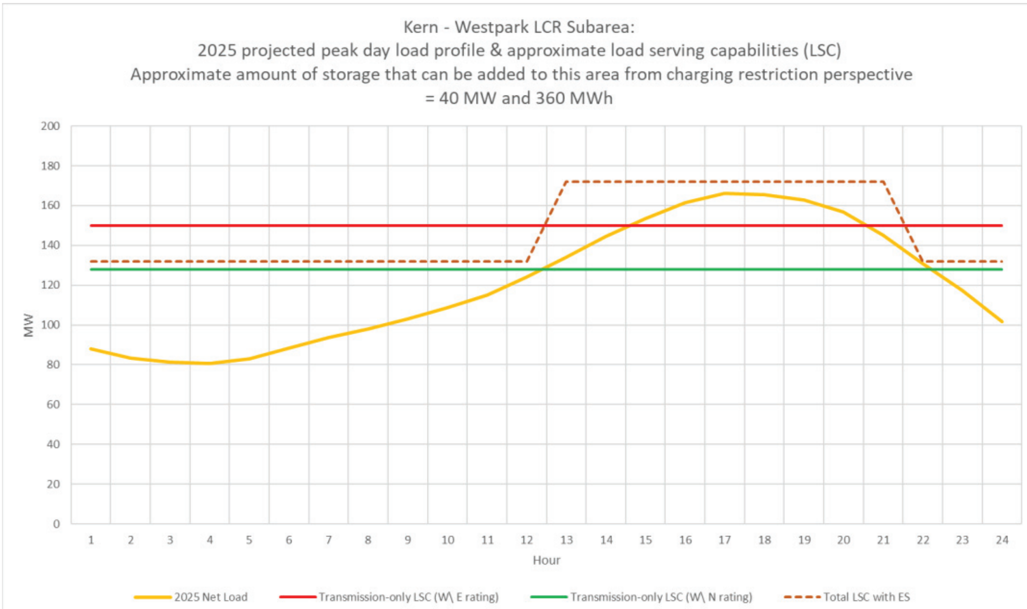
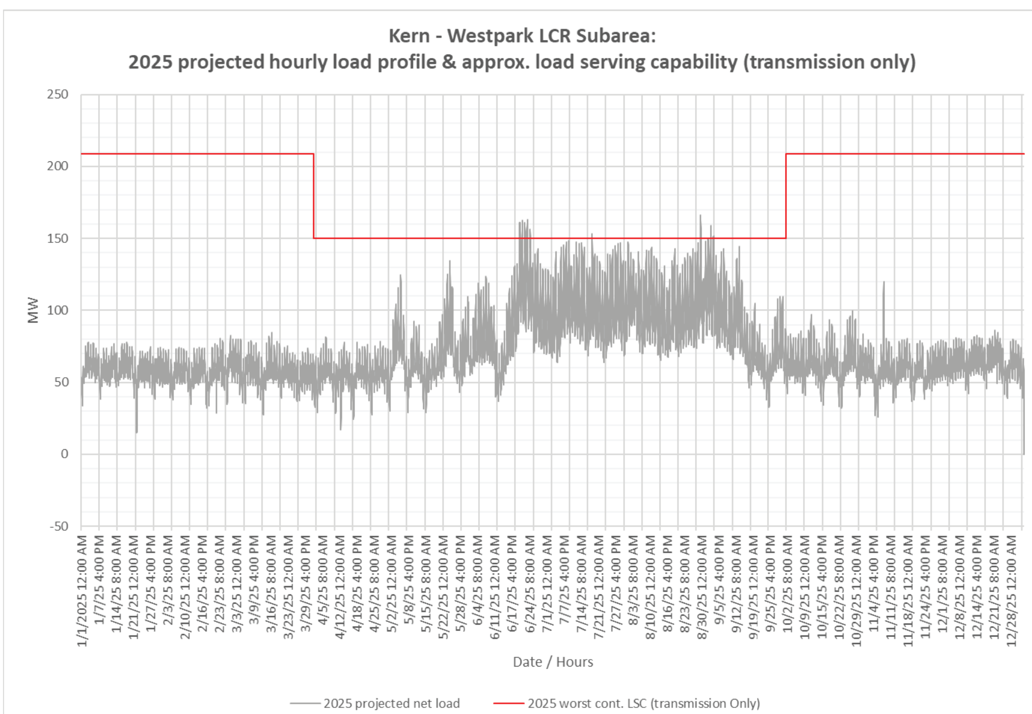


Figure 3.2-67 Westpark LCR Sub-area 2025 Forecast Hourly Profiles



3.2.7.3.4 Westpark LCR Sub-area Requirement

Table 3.2-55 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 20 MW.

Table 3.2-55 Westpark LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Remaining Kern-West Park #1 or #2 115 kV	Kern-West Park #1 or # 2 115 kV & Magunden-Wheeler J # 115 kV	20

3.2.7.3.5 Effectiveness factors:

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

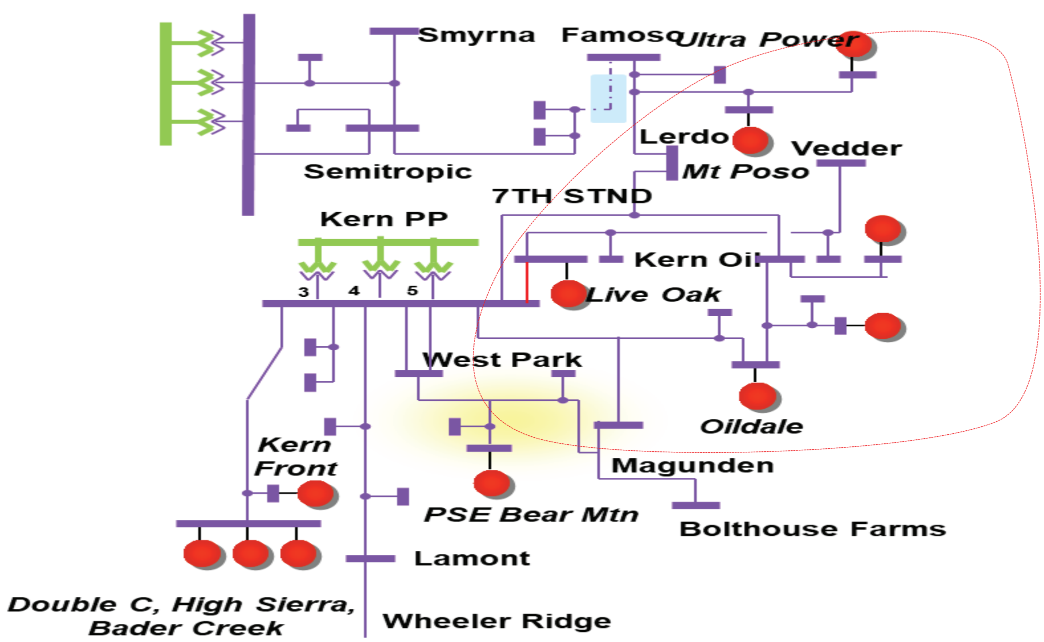
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.7.4 *Kern Oil Sub-area*

Kern Oil is a Sub-area of the Kern LCR Area.

3.2.7.4.1 Kern Oil LCR Sub-area Diagram

Figure 3.2-68 Kern Oil LCR Sub-area



3.2.7.4.2 Kern Oil LCR Sub-area Load and Resources

Table 3.2-56 provides the forecast load and resources in Kern Oil LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-56 Kern Oil LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	300	Market	95	95
AAEE	-3	MUNI	0	0
Behind the meter DG	0	QF	5	5
Net Load	**297**	Solar	7	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**298**	**Total**	**107**	**100**

3.2.7.4.3 Kern Oil LCR Sub-area Hourly Profiles

Figure 3.2-69 illustrates the forecast 2025 profile for the summer peak, winter peak and spring off-peak days for the Kern Oil LCR sub-area with the Category P6 contingency transmission capability without resources. Figure 3.2-70 illustrates the forecast 2025 hourly profile for Kern Oil LCR sub-area with the Category P6 contingency transmission capability without resources.

Figure 3.2-69 Kern Oil LCR Sub-area 2025 Peak Day Forecast Profiles

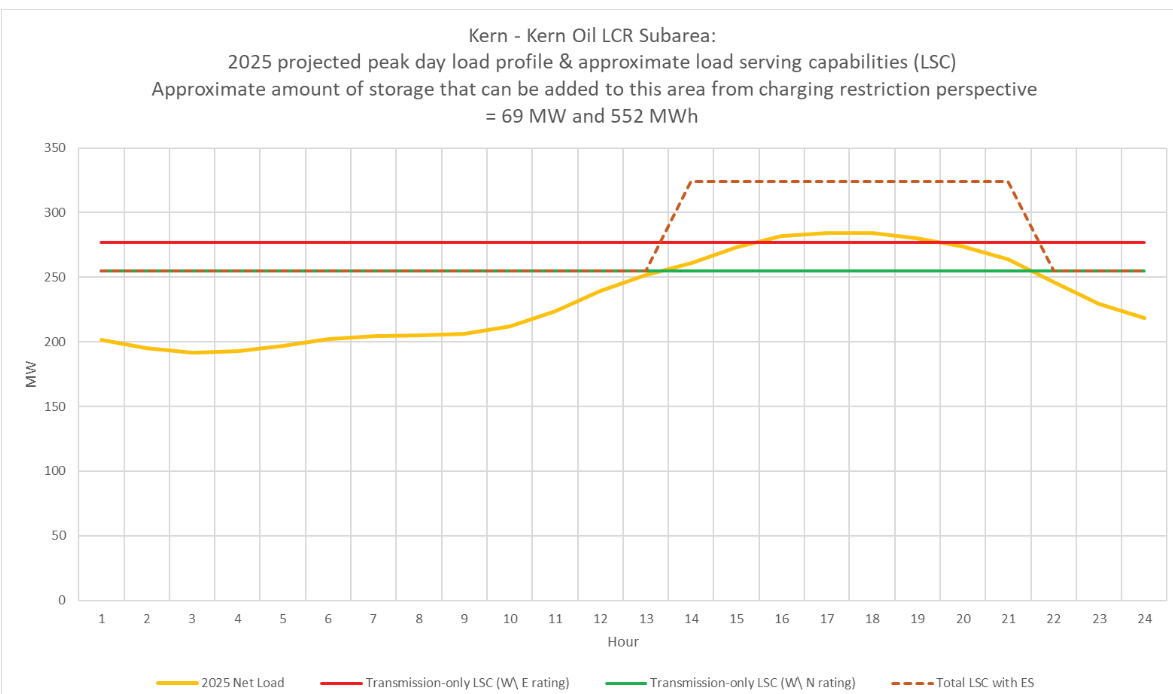
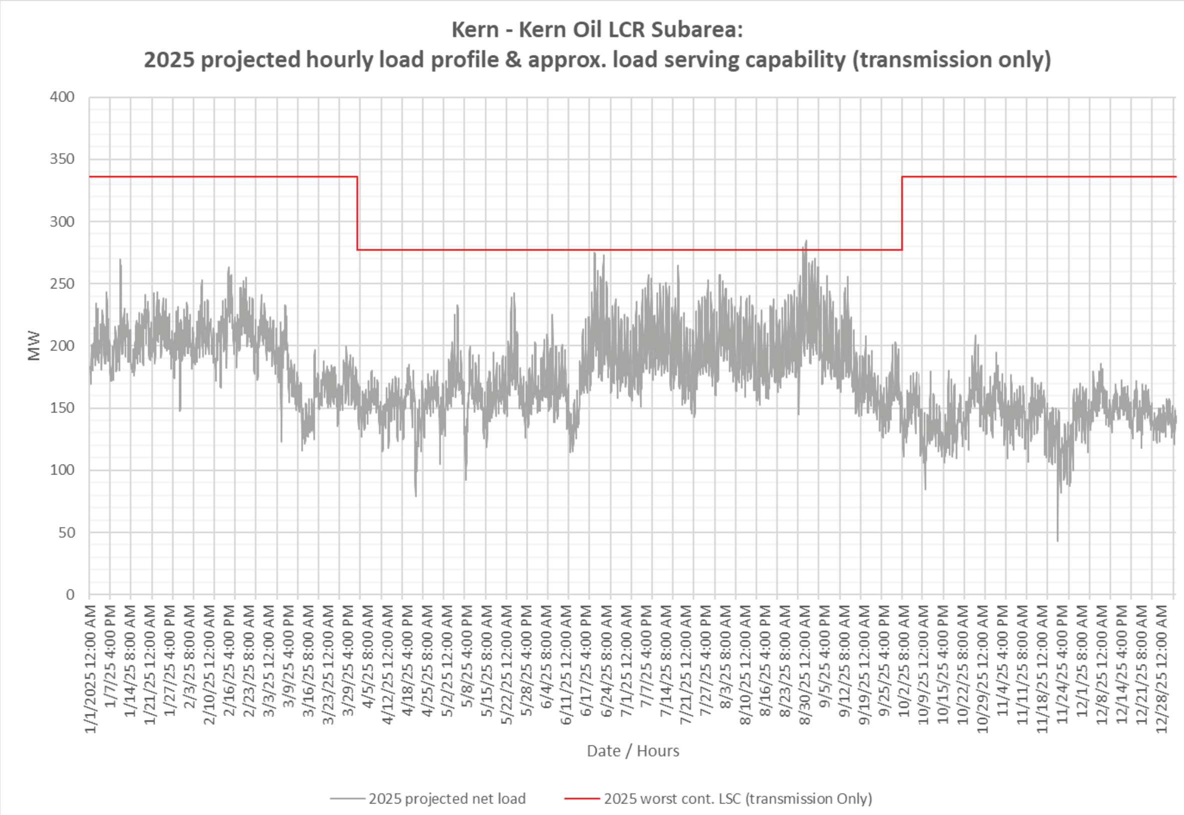


Figure 3.2-70 Kern Oil LCR Sub-area 2025 Forecast Hourly Profiles



3.2.7.4.4 Kern Oil LCR Sub-area Requirement

Table 3.2-57 identifies the sub-area LCR requirements. The LCR requirement for Category Category P6 contingency LCR requirement is 69 MW.

Table 3.2-57 Kern Oil LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency-	LCR (MW) (Deficiency)
2025	First Limit	P6	Kern Oil Jn to Golden Bear 115 kV line section	Kern PP-7th Standard 115 kV & Kern PP-Live Oak 115 kV	69

3.2.7.4.5 **Effectiveness factors:**

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.7.5 *South Kern PP Sub-area*

South Kern PP is Sub-area of the Kern LCR Area.

3.2.7.5.1 South Kern PP LCR Sub-area Diagram

Figure 3.2-71 South Kern PP LCR Sub-area

3.2.7.5.2 South Kern PP LCR Sub-area Load and Resources

Refer to Table 3.2-51 Kern Area Load and Resources table.

3.2.7.5.3 South Kern PP LCR Sub-area Hourly Profiles

Figure 3.2-72 illustrates the forecast 2025 profile for the summer peak, winter peak and spring off-peak days for the South Kern PP LCR sub-area with the Category P6 contingency transmission capability without resources. Figure 3.2-73 illustrates the forecast 2025 hourly profile for South Kern PP LCR sub-area with the Category P6 contingency transmission capability without resources.

Figure 3.2-72 South Kern PP LCR Sub-area 2025 Peak Day Forecast Profiles

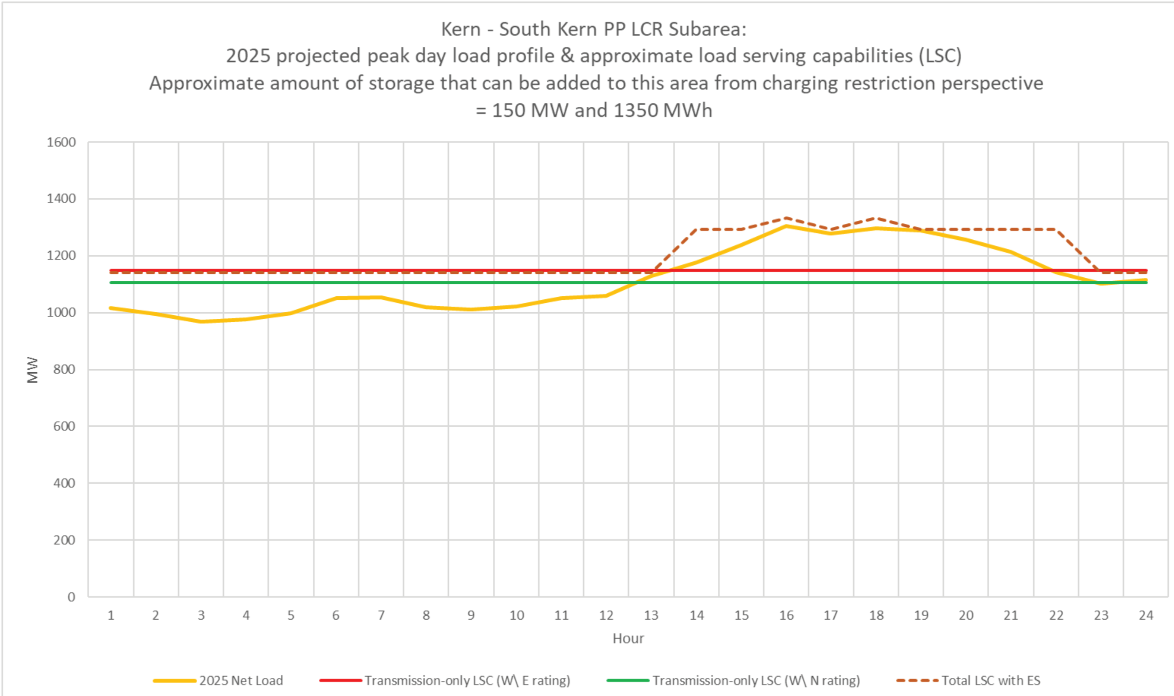
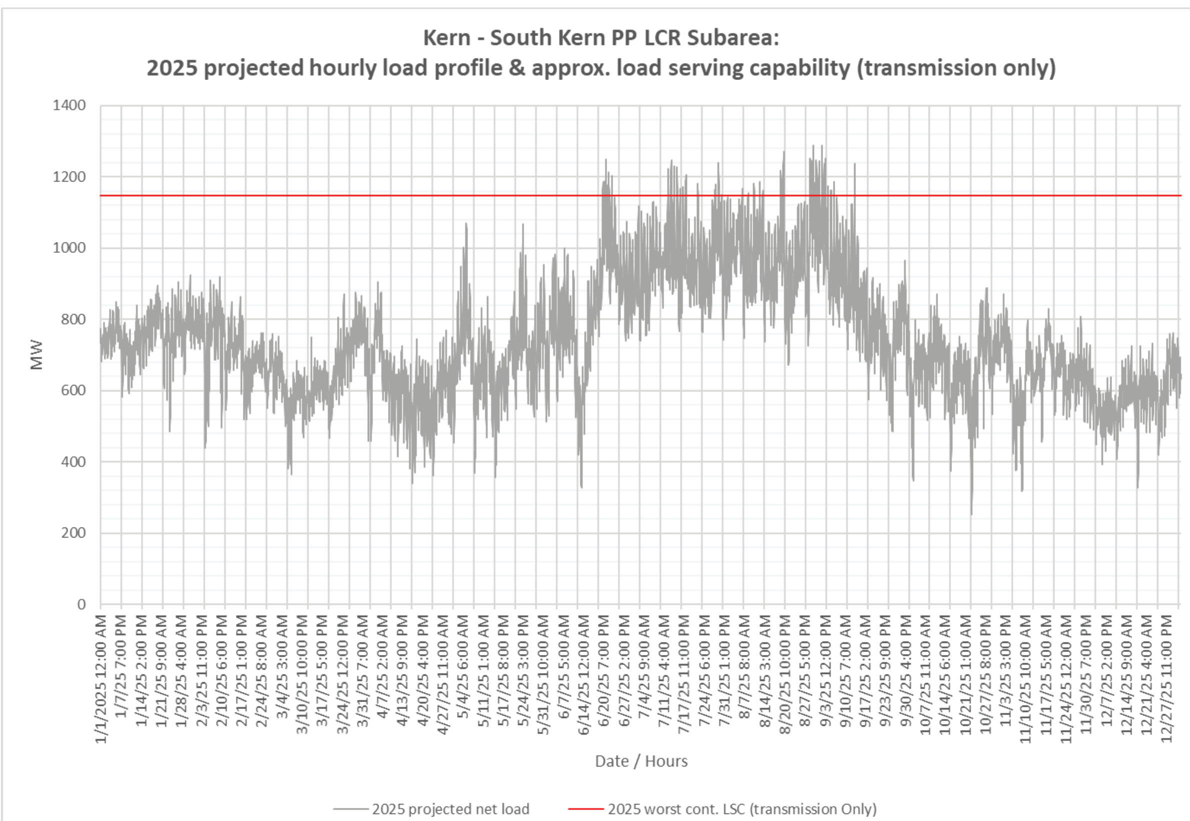


Figure 3.2-73 South Kern Overall LCR Area 2025 Forecast Hourly Profiles



3.2.7.5.4 South Kern PP LCR Sub-area Requirement

Table 3.2-58 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 186 MW.

Table 3.2-58 South Kern PP LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Kern 230/115 kV T/F # 5	Kern 230/115 kV T/F # 3 & Kern 230/115 kV T/F # 4	186

3.2.7.5.5 **Effectiveness factors:**

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.7.6 ***Kern Area Overall Requirements***

3.2.7.6.1 Kern LCR Area Overall Requirement

Table 3.2-59 identifies the limiting facility and contingency that establishes the Kern Area 2025 LCR requirements. The LCR requirement for Category P6 contingency the LCR requirement is 276 MW with a 73 MW NQC deficiency or 86 MW of at peak deficiency.

Table 3.2-59 Kern Overall LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	N/A	P6	Aggregate of Sub-areas.		272 (73 NQC/ 86 Peak)

3.2.7.6.2 Kern Overall LCR Area Hourly Profile

Refer to South Kern PP LCR area profiles.

3.2.7.6.3 Changes compared to 2024 requirements

Compared with 2024, due to the definition change, the load has increased by 748 MW. The LCR requirement has increased by 120 MW mainly due to load forecast increase and change in LCR criteria.

3.2.8 Big Creek/Ventura Area

3.2.8.1 *Area Definition:*

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

Antelope #1 500/230 kV Transformer

Antelope #2 500/230 kV Transformer

Sylmar - Pardee 230 kV #1 and #2 Lines

Vincent - Pardee 230 kV #2 Line

Vincent - Santa Clara 230 kV Line

The substations that delineate the Big Creek/Ventura Area are:

Antelope 500 kV is out Antelope 230 kV is in

Antelope 500 kV is out Antelope 230 kV is in

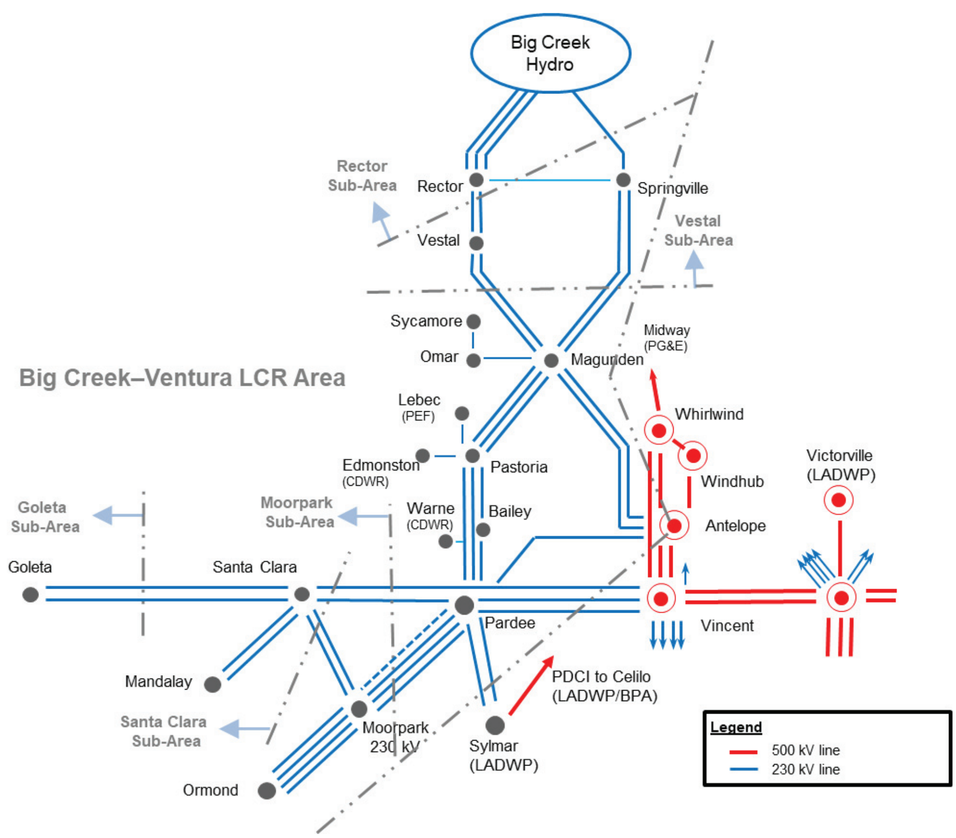
Sylmar is out Pardee is in

Vincent is out Pardee is in

Vincent is out Santa Clara is in

3.2.8.1.1 Big Creek/Ventura LCR Area Diagram

Figure 3.2-74 Big Creek/Ventura LCR Area



3.2.8.1.2 Big Creek/Ventura LCR Area Load and Resources

Table 3.2-60 provides the forecast load and resources in the Big Creek/Ventura LCR area in 2025. The list of generators within the LCR area are provided in Attachment A and does not include new LTPP Preferred resources or existing DR.

In year 2025 the estimated time of local area peak is 5:00 PM.

At the local area peak time the estimated, ISO-metered solar output is 21.9%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-60 Big Creek/Ventura LCR Area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4574	Market, Net Seller, Battery, Wind	2656	2656
AAEE	-76	MUNI	312	312
Behind the meter DG	-403	QF	112	112
Net Load	**4095**	Solar	250	250
Transmission Losses	59	LTPP Preferred Resources (Battery)	207	207
Pumps	275	Existing 20-minute Demand Response	100	100
Load + Losses + Pumps	**4429**	**Total**	**3637**	**3637**

3.2.8.1.3 Approved transmission projects modeled:

Big Creek Corridor Rating Increase Project (completed).

Pardee-Moorpark No. 4 230 kV Transmission Circuit (ISD – 12/31/2020)

Sylmar–Pardee 230 kV Rating Increase Project (ISD – 05/2023)[10]

3.2.8.2 *Rector Sub-area*

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

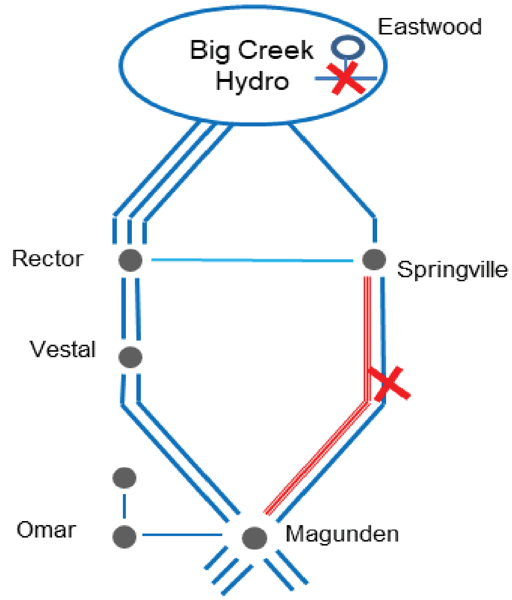
3.2.8.3 *Vestal Sub-area*

Vestal is a Sub-area of the Big Creek/Ventura LCR Area.

3.2.8.3.1 Vestal LCR Sub-area Diagram

[10] Most of the LCR study work was performed without the Sylmar–Pardee 230 kV Rating Increase Project as it was not approved by the CAISO Board yet. Subsequent to its approval, additional studies were performed for the Big Creek Ventura area to determine the LCR with the project included.

Figure 3.2-75 Vestal LCR Sub-area



3.2.8.3.2 Vestal LCR Sub-area Load and Resources

Table 3.2-61 provides the forecast load and resources in Vestal LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

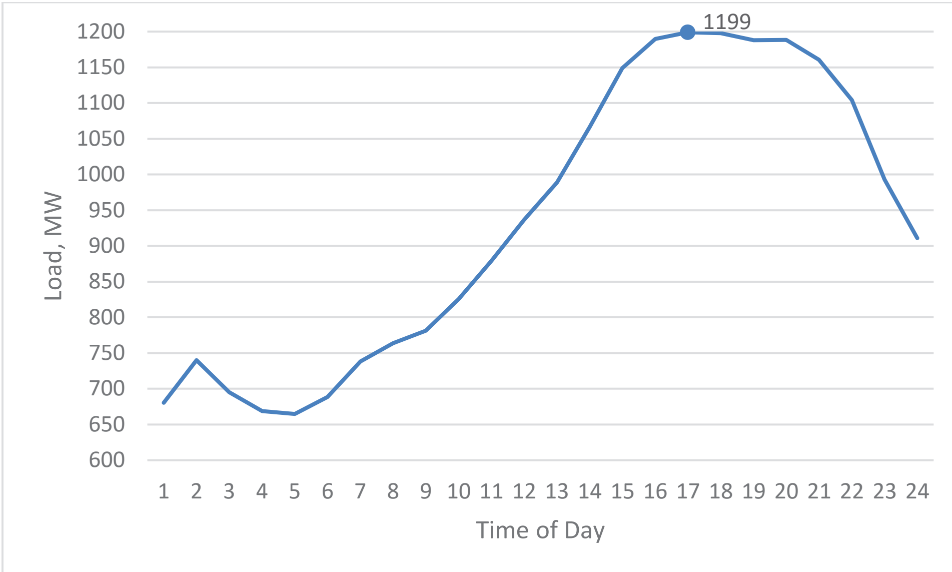
Table 3.2-61 Vestal LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	N/A	Market, Net Seller, Battery, Wind	1055	1055
AAEE	N/A	MUNI	0	0
Behind the meter DG	N/A	QF	22	22
Net Load	**1199**	Solar	9	9
Transmission Losses	29	LTPP Preferred Resources	0	0
Pumps	0	Existing 20-minute Demand Response	41	41
Load + Losses + Pumps	**1228**	**Total**	**1127**	**1127**

3.2.8.3.3 Vestal LCR Sub-area Hourly Profiles

Figure 3.2-76 illustrates the forecast 2025 profile for the summer peak day in the Vestal LCR sub-area based on the CEC hourly forecast for the SCE area.

Figure 3.2-76 Vestal LCR Sub-area 2025 Peak Day Forecast Profiles



3.2.8.3.4 Vestal LCR Sub-area Requirement

Table 3.2-62 identifies the sub-area LCR requirements. The 2025 LCR requirement for Category P3 contingency are the same, is 310 MW.

Table 3.2-62 Vestal LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P3	Magunden–Springville #2 230 kV line	Magunden–Springville #1 230 kV line with Eastwood out of service	310

3.2.8.3.5 Effectiveness factors:

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

3.2.8.4 *Goleta Sub-area*

Goleta is a Sub-area of the Big Creek/Ventura LCR Area.

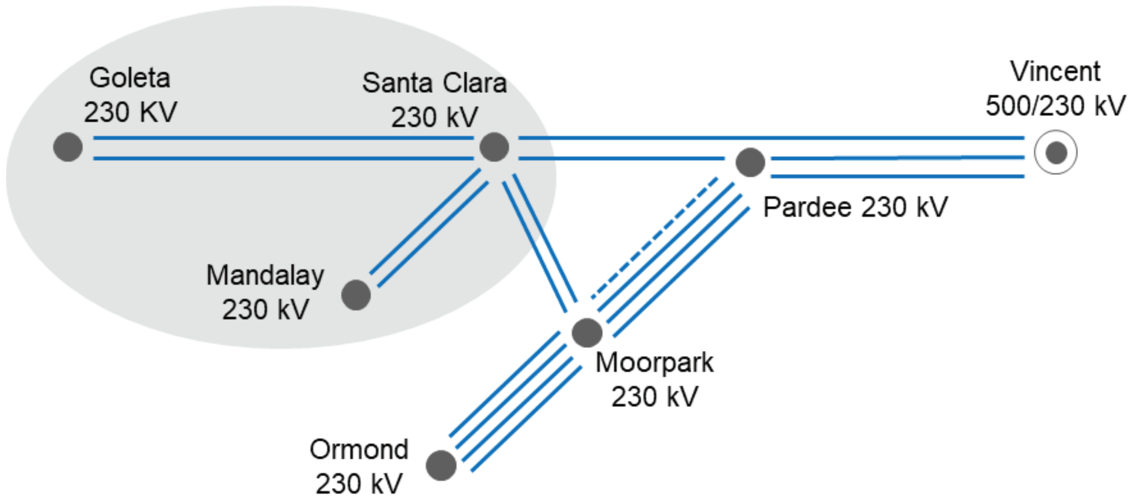
The LCR need is satisfied by the need in the larger Santa Clara sub-area.

3.2.8.5 *Santa Clara Sub-area*

Santa Clara is a Sub-area of the Big Creek/Ventura LCR Area.

3.2.8.5.1 Santa Clara LCR Sub-area Diagram

Figure 3.2-77 Santa Clara LCR Sub-area



3.2.8.5.2 Santa Clara LCR Sub-area Load and Resources

Table 3.2-63 provides the forecast load and resources in Santa Clara LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

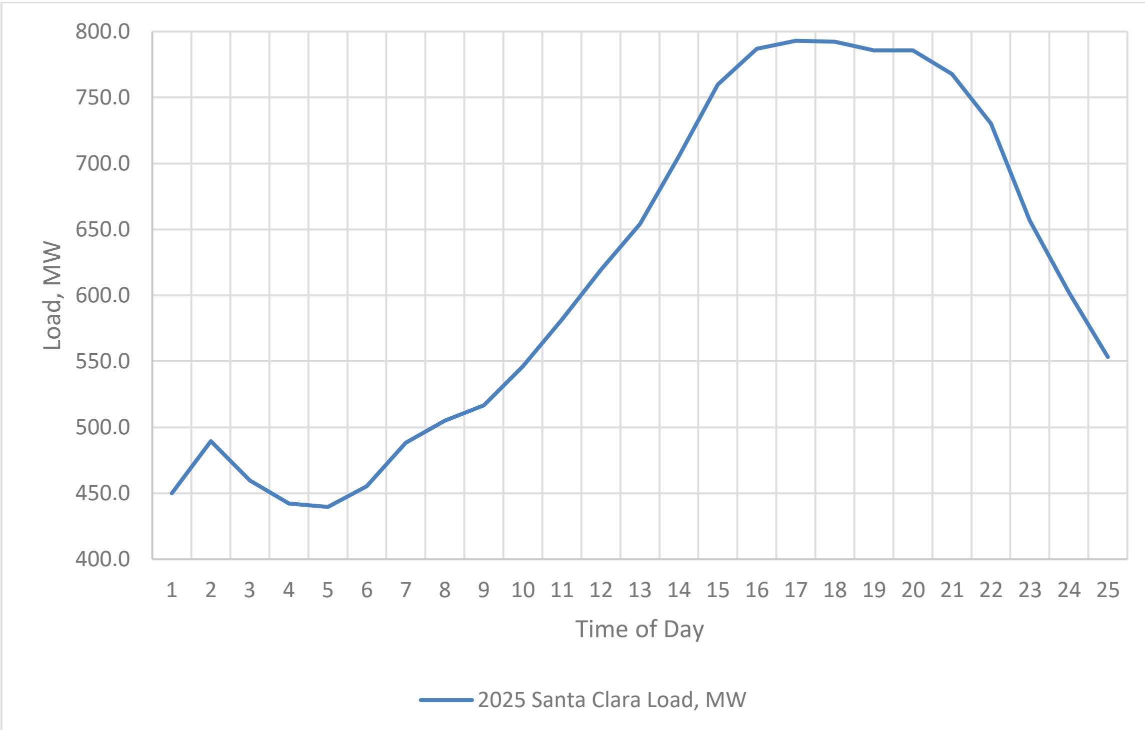
Table 3.2-63 Santa Clara LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	N/A	Market	156	156
AAEE	N/A	MUNI	0	0
Behind the meter DG	N/A	QF	84	84
Net Load	**793**	LTPP Preferred Resources (Battery)	195	195
Transmission Losses	2	Existing Demand Response	7	7
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**795**	**Total**	**442**	**442**

3.2.8.5.3 Santa Clara LCR Sub-area Hourly Profiles

Figure 3.2-78 illustrates the forecast 2025 profile for the summer peak day in the Santa Clara LCR sub-area based on the CEC forecast load shape for the SCE TAC area.

Figure 3.2-78 Santa Clara LCR Sub-area 2025 Peak Day Forecast Profiles



3.2.8.5.4 Santa Clara LCR Sub-area Requirement

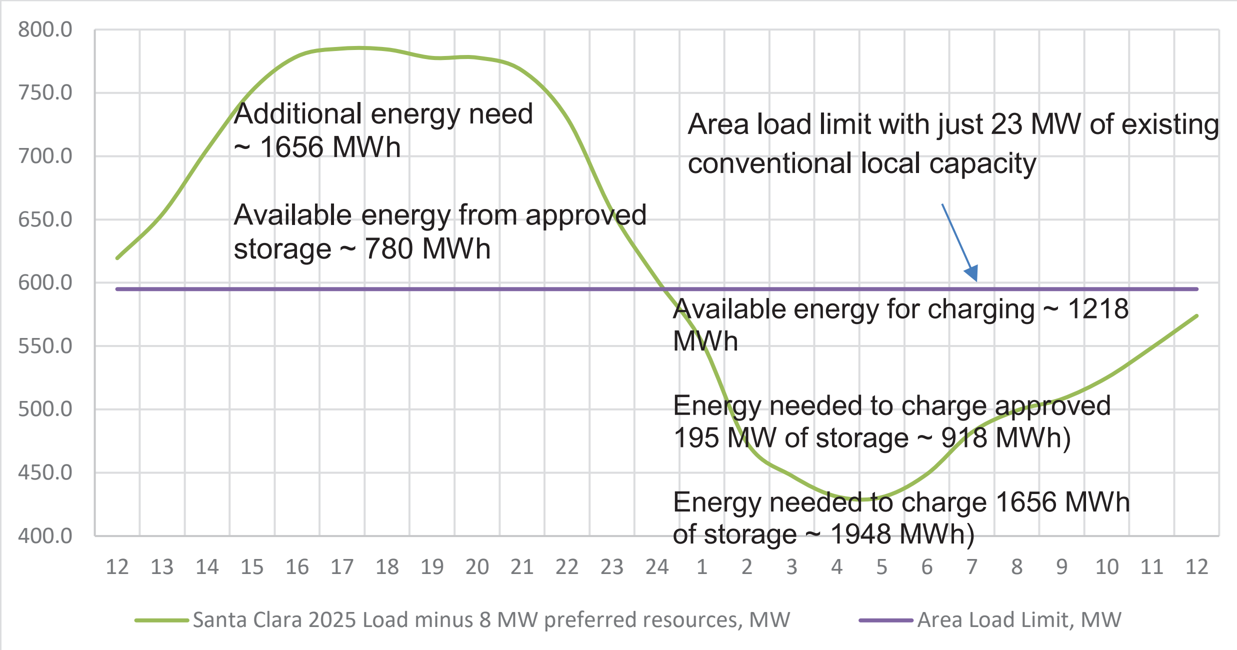
Table 3.2-64 identifies the sub-area requirement. The LCR requirement for Category P1 + P7 contingency is 225 MW.

Table 3.2-64 Santa Clara LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P1 + P7	Voltage collapse	Pardee - Santa Clara 230 kV followed by Moorpark - Santa Clara #1 & #2 230 kV	225

The Santa Clara sub-area could be energy deficient if the resources selected to meet the LCR do not include sufficient conventional generation. Figure 3.2-79 shows the scenario where the 229 MW LCR is to be filled with 195 MW of contracted storage, 7 MW of existing preferred resources and the remainder 23 MW with gas. In this scenario the the sub area will be energy deficient and will not have sufficient offpeak energy to charge additional batteries for next day use.

Figure 3.2-79 Santa Clara Sub-area Stoage Analyisis



3.2.8.5.5 Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7500, 7510, 7550 , 7680 and 8610 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.8.6 *Moorpark Sub-area*

Moorpark is a Sub-area of the Big Creek/Ventura LCR Area.

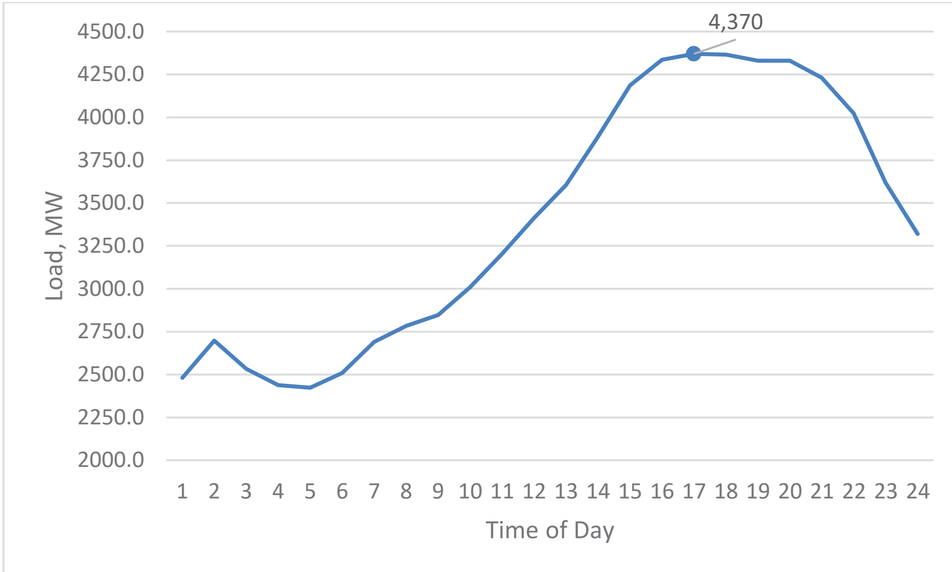
No requirement is identified for the sub-area due Pardee-Moorpark No. 4 230 kV Transmission Project.

3.2.8.7 *Big Creek/Ventura Overall*

3.2.8.7.1 Big Creek/Ventura LCR Sub-area Hourly Profiles

Figure 3.2-80 illustrates the forecast 2025 profile for the summer peak day in the Big Creek/Ventura LCR area based on the CEC load shape for SCE TAC area.

Figure 3.2-80 Big Creek/Ventura LCR area 2025 Peak Day Forecast Profiles



3.2.8.7.2 Big Creek/Ventura LCR area Requirement

Table 3.2-65 identifies the area LCR requirements. The LCR for the area was assessed with and without the Sylmar–Pardee 230 kV Rating Increase Project. The LCR requirement for Category P6 contingency is 1002 MW with the project and 2652 MW without the project.

Table 3.2-65 Big Creek/Ventura LCR area Requirements

Year	First Limit	Category	Limiting Facility	Contingency	LCR (MW) [11]
2025	With Sylmar–Pardee Project	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	1002
2025	Without Sylmar–Pardee Project	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	2652

3.2.8.7.3 Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7500, 7510, 7550, 7680 and 8610 posted at: http://www.caiso.com/Documents/2210Z.pdf

[11] The current assessment indicates a larger LCR reduction due to the Sylmar–Pardee project compared to the assessment that was performed for the project as part of the 2019-2020 TPP. The limiting contingency that established the LCR in the 2019-2020 TPP case was the P6 outage of one PDCI line and one Antelope 500/230 kV transformer which overloaded the remaining transformer. That contingency was not found to be binding in the current assessment likely due to the reduced output from renewables in the Antelope, Windhub and Whirlwind area that is modeled in the current base case because of the reduced NQC of wind and solar.

3.2.8.7.4 Changes compared to 2024 LCT study

Compared with the results for 2024, the load forecast is down by 529 MW and the LCR went down by 1575 MW because of the Sylmar–Pardee 230 kV Rating Increase Project.

3.2.8.7.5 Energy Storage Analsysis

The Big Creek-Ventura area and sub-areas were assessed to estimate the maximum amount of storage that can be added to displace local gas generation without exceeding the available off-peak charging capability in the area. The analysis is based on the following assumptions.

- Load shape is based on the CEC hourly forecast for SCE TAC area
- Energy storage is assumed to be added at the same location and amount as the displaced gas generation
- A round-trip efficiency of 85% is assumed for energy storage
- The assessment was initially performed without modeling the Sylmar–Pardee 230 kV upgrade project as its approval by the ISO Board was pending. Given its recent approval an assessment was performed with the project modeled.

Table 3.2-65 provides the results of the assessment. As shown in the table, adding storage for Rector, Vestal, Goleta, Santa Clara or Moorpark sub-areas will not enable displacing gas-fired generation because the subarea does not either have a local capacity requirement, the local capacity requirement is largely met by hydro resources, or in the Santa Clara, the area is already saturated with storage local capacity resources.

The assessment performed for the greater Big Creek-Ventura area without the Sylmar–Pardee Project shown in Figure 3.2-81 indicates roughly up to 882 MW/6667 MWh of new energy storage can be added to replace gas-fired local capacity without experiencing charging limitations. However, as can be seen in Figure 3.2-82 the approved Sylmar–Pardee project will eliminate the need for gas-fired local capacity in the area (with the exception of the Santa Clara sub-area) and as a result the addition of new storage will not result in the displacement of gas-fired local capacity.

Notes:

• Effective net load= hourly load minus hourly area IFOM PV output adjusted for effectiveness minus hourly area DR dispatch

• Area net load limit is iteratively calculated using Excell to equalize the area above load limit line with area below, taking into account battery efficiency

HE-17, HE-21 and next day HE-10 were tested in power flow and the initial estimate was reduced due to charging constraints related to HE-10

Figure 3.2-81 Big Creek/Ventura Local Capacity Energy Storage Analysis without Sylmar–Pardee Project

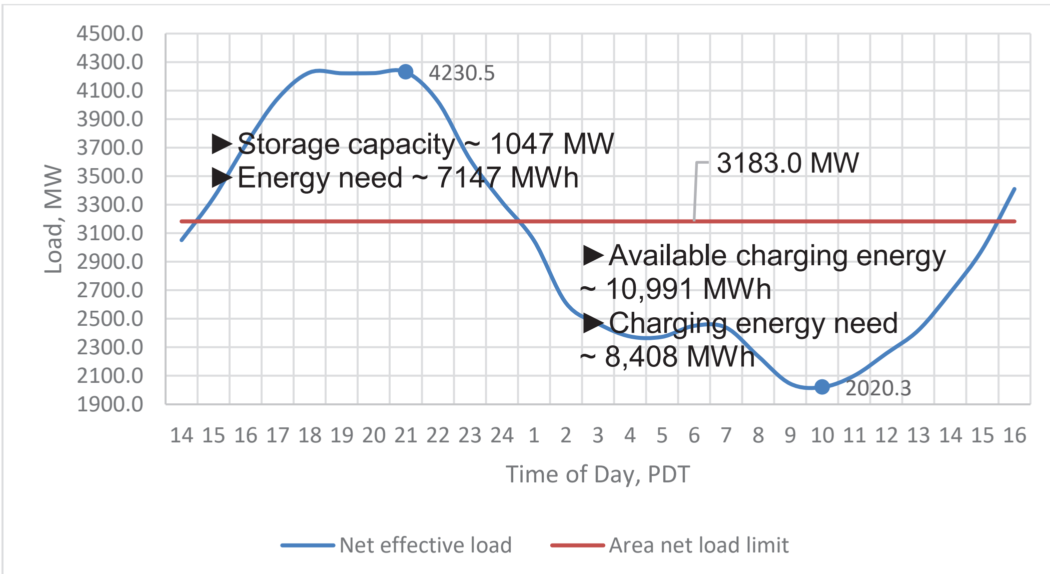
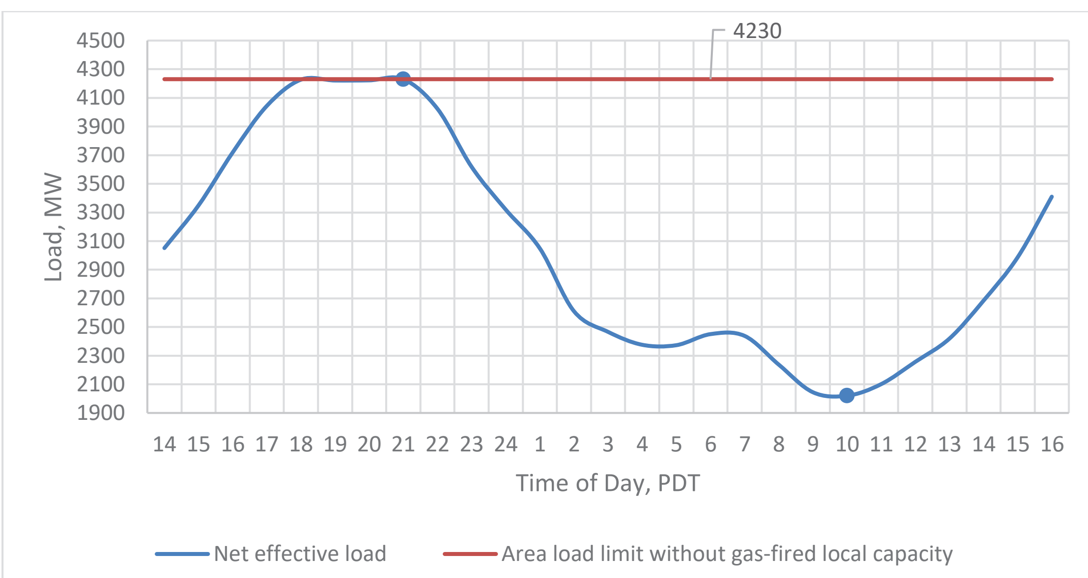


Figure 3.2-82 Big Creek/Ventura Local Capacity Energy Storage Analysis with Sylmar–Pardee Project



Post Pardee–Sylmar project LCR can be fully met with non-gas resources including approved energy storage, hydro, solar and demand response that new energy storage is not anticipated to replace.

Table 3.2-66 Summary of Big Creek/Ventura Energy Storage Local Capacity Analysis Results

Area	LCR (2025), MW	Maximum energy storage that can be added to replace gas-fired local capacity		Remark
		Capacity (MW)	Energy (MWh)	
Rector	0	0	0	No LCR requirement
Vestal	310	0	0	No gas-fired local capacity
Goleta	0	0	0	No LCR requirement
Santa Clara	225	0	0	Area is saturated with approved energy storage
Moorpark	0	0	0	No LCR requirement
Overall Big Creek–Ventura Total	2,652	1,047	7147	Pre Sylmar–Pardee Project
Overall Big Creek–Ventura Incremental to approved ES		852	6367	
Overall Big Creek–Ventura Post Sylmar Pardee Project	1002	0	0	No gas-fired local capacity requirement post Sylmar–Pardee Project (other than in the Santa Clara sub-area)

3.2.9 LA Basin Area

3.2.9.1 *Area Definition:*

The transmission tie lines into the LA Basin Area are:

San Onofre - San Luis Rey #1, #2, and #3 230 kV Lines

San Onofre - Talega #1 230 kV Lines

San Onofre - Capistrano #1 230 kV Lines

Lugo - Mira Loma #2 & #3 500 kV Lines

Lugo - Rancho Vista #1 500 kV Line

Vincent – Mesa 500 kV Line

Sylmar - Eagle Rock 230 kV Line

Sylmar - Gould 230 kV Line

Vincent - Mesa #1 & #2 230 kV Lines

Vincent - Rio Hondo #1 & #2 230 kV Lines

Devers - Red Bluff 500 kV #1 and #2 Lines

Mirage – Coachella Valley # 1 230 kV Line

Mirage - Ramon # 1 230 kV Line

Mirage - Julian Hinds 230 kV Line

The substations that delineate the LA Basin Area are:

San Onofre is in San Luis Rey is out

San Onofre is in Talega is out

San Onofre is in Capistrano is out

Mira Loma is in Lugo is out

Rancho Vista is in Lugo is out

Eagle Rock is in Sylmar is out

Gould is in Sylmar is out

Mira Loma is in Vincent is out

Mesa is in Vincent is out

Rio Hondo is in Vincent is out

Devers is in Red Bluff is out

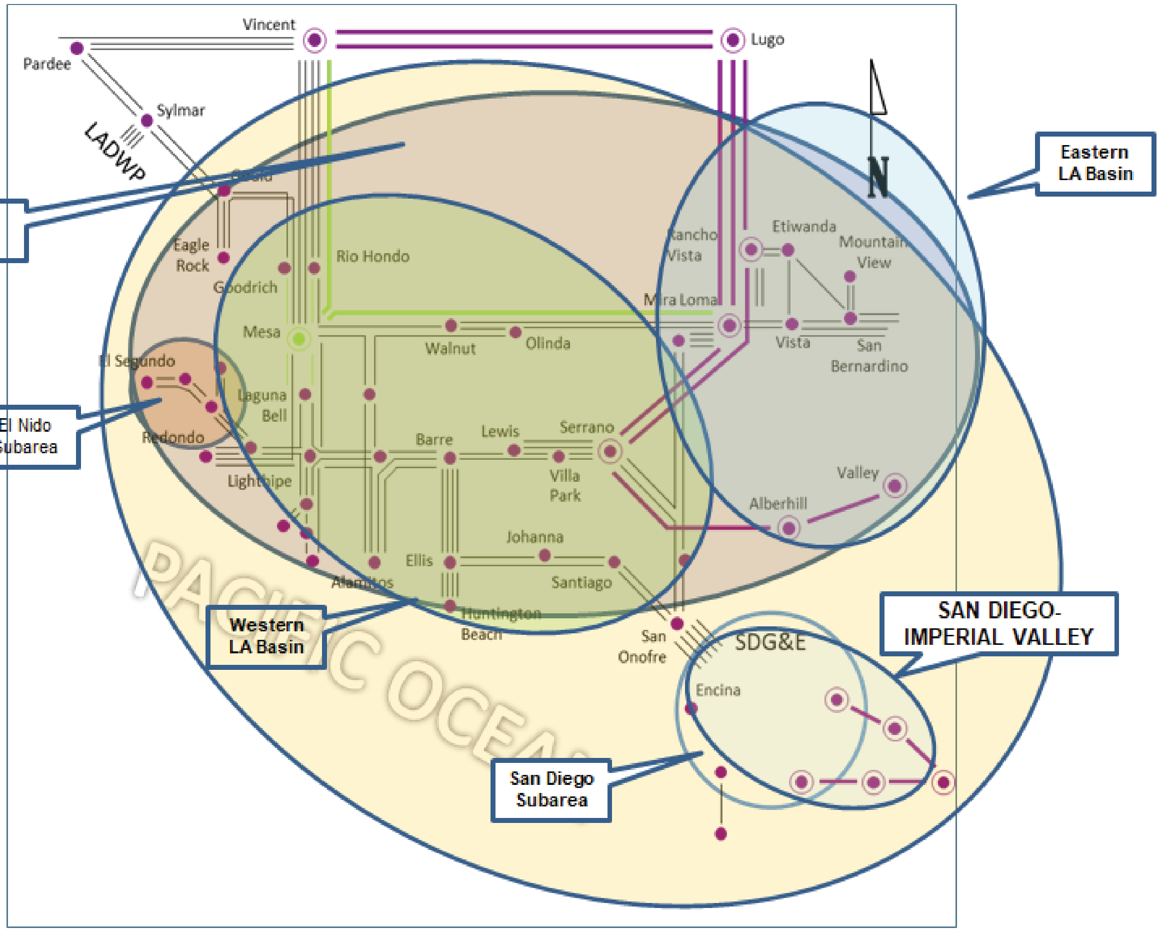
Mirage is in Coachella Valley is out

Mirage is in Ramon is out

Mirage is in Julian Hinds is out

3.2.9.1.1 LA Basin LCR Area Diagram

Figure 3.2-83 LA Basin LCR Area



3.2.9.1.2 LA Basin LCR Area Load and Resources

Table 3.2-67 provides the forecast load and resources in the LA Basin LCR area in 2025. The list of generators within the LCR area are provided in Attachment A and does not include new LTPP Preferred resources or DR.

In year 2025 the estimated time of local area peak is 5:00 PM (PDT) on September 2, 2025.

At the local area peak time the estimated, ISO metered, solar output is 14%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-67 LA Basin LCR Area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	21065	Market, Net Seller, Battery, Wind	5597	5597
AAEE	-382	MUNI	1056	1056
Behind the meter DG	-2,159	QF	141	141
Net Load	**18524**	LTPP Preferred Resources (BTM BESS, EE, DR, PV)	331	331

Transmission Losses	282	Existing Demand Response	287	287
Pumps	20	Solar	11	11
Load + Losses + Pumps	**18826**	**Total**	**7423**	**7423**

3.2.9.1.3 Approved transmission and resource projects modeled:

Mesa Loop-In Project and Laguna Bell Corridor 230 kV line upgrades

Delaney – Colorado River 500 kV Line

West of Devers 230 kV line upgrades

CPUC-approved long-term procurement plan for preferred resources in the western LA Basin sub-area

Retirement of Redondo Beach OTC generation (Units 5, 6 and 8)

Alamitos repowering

Alamitos battery energy storage system (100 MW / 400 MWh)

Retirement of Alamitos OTC generation (Units 3, 4, and 5)

Huntington Beach repowering

Retirement of Huntington Beach OTC generation

Stanton Energy Reliability Center (98 MW)

3.2.9.2 *El Nido Sub-area*

El Nido is Sub-area of the LA Basin LCR Area.

3.2.9.2.1 El Nido LCR Sub-area Diagram

Please refer to Figure 3.2-83 above.

3.2.9.2.2 El Nido LCR Sub-area Load and Resources

Table 3.2-68 provides the forecast load and resources in El Nido LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-68 El Nido LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	1086	Market, Net Seller, Battery, Wind, Solar	534	534
AAEE	-34	MUNI	3	3
Behind the meter DG	-47	QF	0	0
Net Load	**1005**	LTPP Preferred Resources	23	23

Transmission Losses	2	Existing Demand Response	9	9
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1007**	**Total**	**569**	**569**

3.2.9.2.3 El Nido LCR Sub-area Hourly Profiles

Figure 3.2-84 illustrates the forecast 2025 profile for the summer peak day in the El Nido LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local gas resources.

Figure 3.2-85 and Figure 3.2-86 illustrate that load serving capability is higher by retaining some local gas generation in the sub-area, some amount of energy storage for the overall area can be accommodated and be limited by the charging capability under the extended transmission contingency condition. For this case, an estimated 250 MW and 2000 MWh of energy storage can be accommodated from the charging limitation perspective as shown on Figure 3.2-86.

Figure 3.2-84 El Nido LCR Sub-area 2025 Peak Day Forecast Profiles

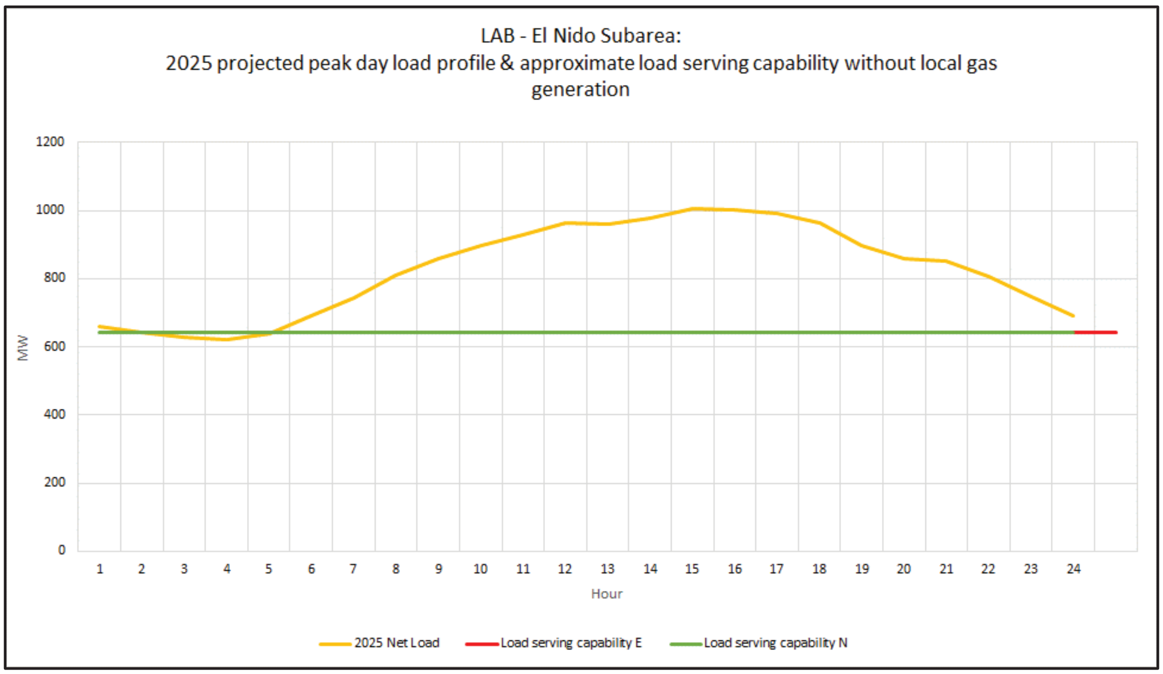


Figure 3.2-85 El Nido LCR Sub-area 2025 Peak Day Forecast Profiles with Higher Load Serving Capability

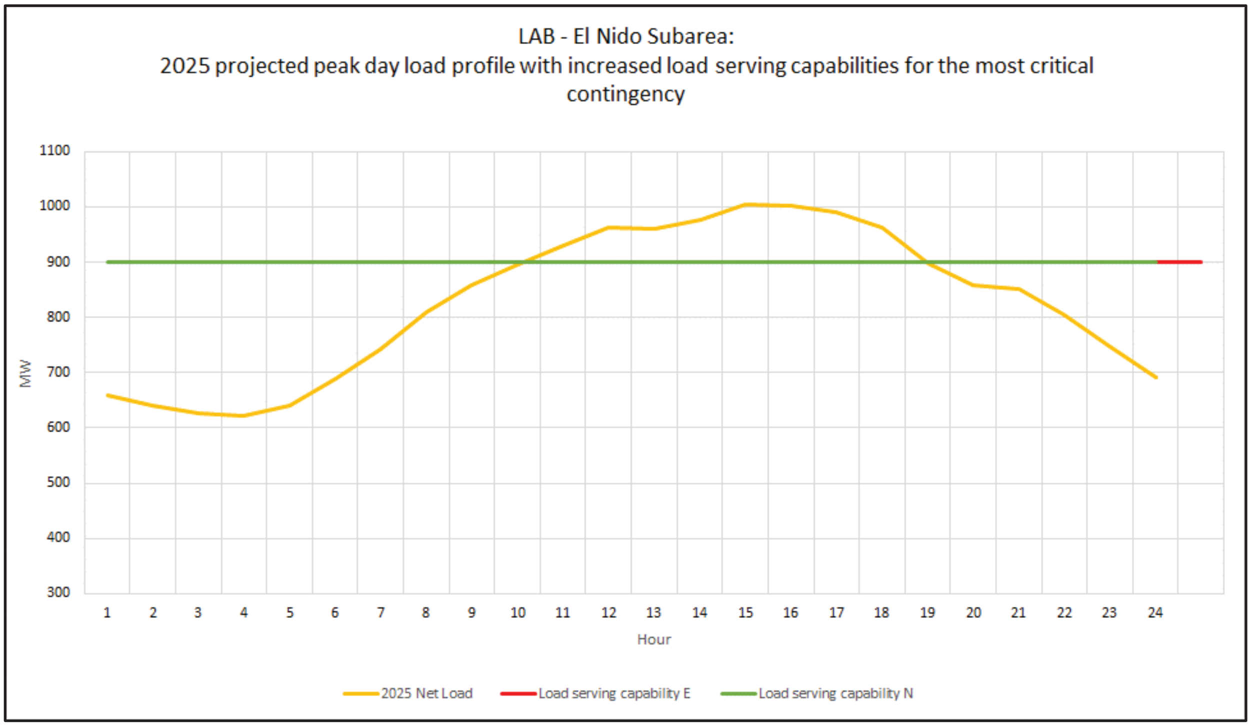
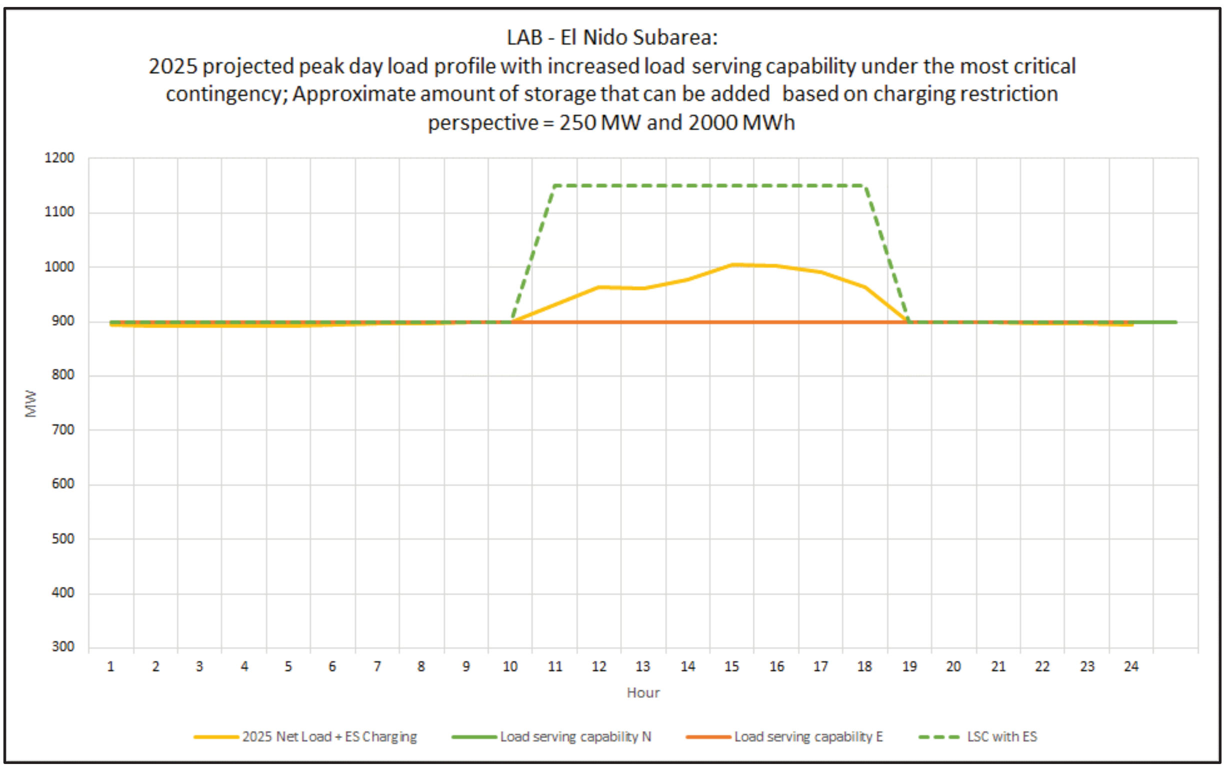


Figure 3.2-86 El Nido LCR Sub-area 2021 Estimated Amount of Storage that Can Be Added With Higher Load Serving Capability



3.2.9.2.4 El Nido LCR Sub-area Requirement

Table 3.2-69 identifies the sub-area requirements. The LCR requirement for Category P7 contingency is 409 MW.

Table 3.2-69 El Nido LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P7	La Fresa-La Cienega 230 kV	La Fresa – El Nido #3 & #4 230 kV	409

3.2.9.2.5 Effectiveness factors:

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7630 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.9.3 *Western LA Basin Sub-area*

Western LA Basin is a Sub-area of the LA Basin LCR Area.

3.2.9.3.1 Western LA Basin LCR Sub-area Diagram

Please refer to Figure 3.2-83 above.

3.2.9.3.2 Western LA Basin LCR Sub-area Load and Resources

Table 3.2-70 provides the forecast load and resources in Western LA Basin LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A. Due to the interaction between Western and Eastern LA Basin, as well as with the San Diego-Imperial Valley areas, the load profile with load serving capability, and the energy storage addition based on its charging capability are evaluated and included in the overall LA Basin.

Table 3.2-70 Western LA Basin Sub-area 2025 Forecast Load and Resources

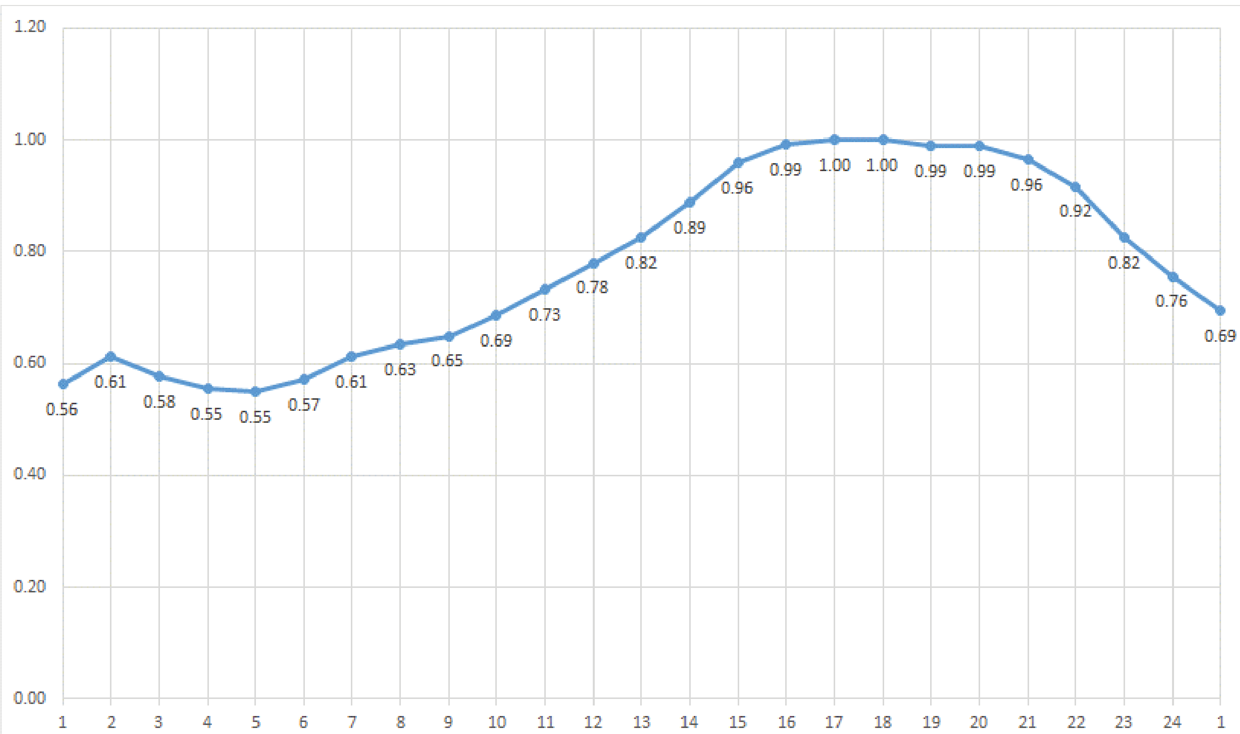
Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	12309	Market, Net Seller, Battery, Wind	3212	3212
AAEE	-466	MUNI	584	584
Behind the meter DG	-719	QF	58	58
Net Load	**11124**	LTPP Preferred Resources (BTM BESS, EE, DR, PV)	331	331
Transmission Losses	167	Existing Demand Response	161	161

Pumps	0	Solar	2	2
Load + Losses + Pumps	**11291**	**Total**	**4348**	**4348**

3.2.9.3.3 Western LA Basin LCR Sub-area Hourly Profiles

Figure 3.2-87 illustrates the forecast 2025 profile for the summer peak day in the Western LA Basin LCR sub-area. Due to the interaction between Western and Eastern LA Basin, as well as with the San Diego-Imperial Valley areas, the load profile with load serving capability, and the energy storage addition based on its charging capability are evaluated and included for the overall LA Basin.

Figure 3.2-87 Western LA Basin LCR Sub-area 2025 Peak Day Forecast Profiles



3.2.9.3.4 Western LA Basin LCR Sub-area Requirement

Table 3.2-71 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 3943 MW. The 2025 LCR need is higher than 2024 LCR need due to CEC and SCE reallocation of substation loads resulting in a higher amount in Western LA Basin.

Table 3.2-71 Western LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Mesa-Laguna Bell 230 kV	Mesa-La Fresa 230 kV, followed by Mesa-Lighthipe 230 kV line or vice versa	3943

3.2.9.3.5 Effectiveness factors:

See Attachment B - Table titled LA Basin.

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

There are other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area 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, these effectiveness factors may not be the best indicator towards informed procurement.

3.2.9.4 *West of Devers Sub-area*

West of Devers is a Sub-area of the LA Basin LCR Area.

There are no local capacity requirements due to implementation of the Mesa Loop-in as well as West of Devers reconductoring projects.

3.2.9.5 *Valley-Devers Sub-area*

Valley-Devers is a Sub-area of the LA Basin LCR Area.

There are no local capacity requirements due to implementation of the Colorado River-Delaney 500 kV line project.

3.2.9.6 *Valley Sub-area*

Valley is a Sub-area of the LA Basin LCR Area.

There are no local capacity requirements due to implementation of the Colorado River-Delaney 500 kV line project.

3.2.9.7 *Eastern LA Basin Sub-area*

Eastern LA Basin is a Sub-area of the LA Basin LCR Area.

3.2.9.7.1 Eastern LA Basin LCR Sub-area Diagram

Please refer to Figure 3.2-83 above.

3.2.9.7.2 Eastern LA Basin LCR Sub-area Load and Resources

Table 3.2-72 provides the forecast load and resources in Eastern LA Basin LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

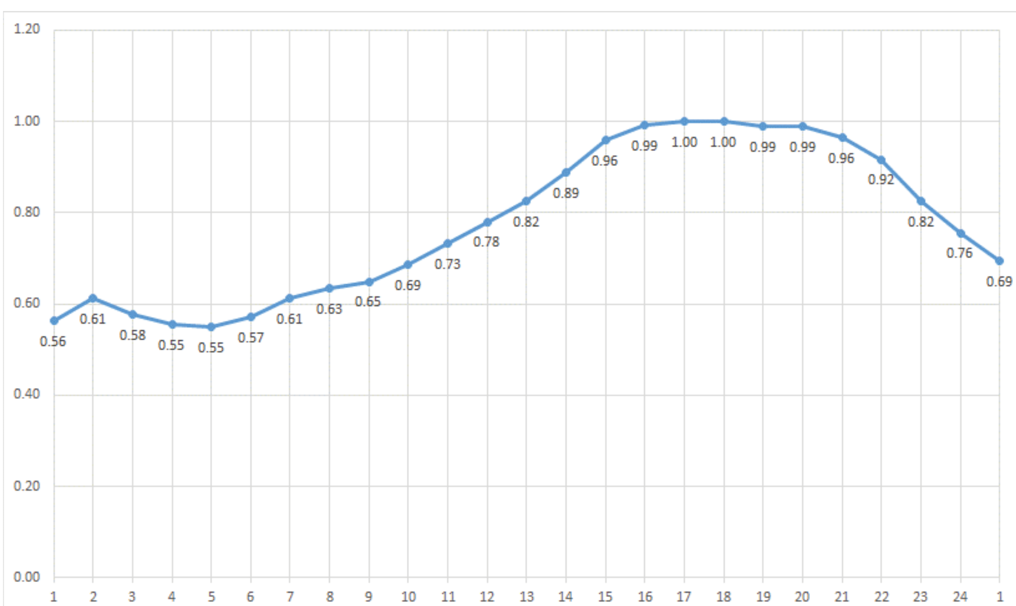
Table 3.2-72 Eastern LA Basin Sub-area 2025 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	8355	Market, Net Seller, Battery, Wind	2384	2384
AAEE	-273	MUNI	472	472
Behind the meter DG	-683	QF	83	83
Net Load	**7399**	LTPP Preferred Resources	0	0
Transmission Losses	111	Existing Demand Response	126	126
Pumps	20	Solar	9	9
Load + Losses + Pumps	**7530**	**Total**	**3074**	**3074**

3.2.9.7.3 Eastern LA Basin LCR Sub-area Hourly Profiles

Figure 3.2-88 illustrates the forecast 2025 profile for the summer peak day in the Eastern LA Basin LCR sub-area. Due to the interaction between Western and Eastern LA Basin, as well as with the San Diego-Imperial Valley areas, the load profile with load serving capability, and the energy storage addition based on its charging capability are evaluated and included for the overall LA Basin.

Figure 3.2-88 Eastern LA Basin LCR Sub-area 2025 Peak Day Forecast Profiles



3.2.9.7.4 Eastern LA Basin LCR Sub-area Requirement

Table 3.2-73 identifies the sub-area LCR requirements. The LCR requirement for Category P1+P7 contingency is 2477 MW. The 2025 LCR need for the Eastern LA Basin is lower due than the 2024 local capacity need due to lower import levels from the Southwest because of base-load generation retirement in Arizona. Lower import level results in less line voltage drop, lessening voltage stability concern. As well as higher LCR level in the Western LA Basin results in lower voltage drop, lessening voltage stability concern.

Table 3.2-73 Eastern LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P1+P7	Post transient voltage stability	Alberhill-Serrano 500 kV, followed by Devers–Red Bluff #1 and #2 500 kV	2366

3.2.9.7.5 Effectiveness factors:

All units within the Eastern LA Basin sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7750 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.9.8 *LA Basin Overall*

3.2.9.8.1 LA Basin LCR Sub-area Hourly Profiles

Figure 3.2-89 illustrates the forecast 2025 profile for the summer peak day in the LA Basin LCR area with the Category P1 normal and emergengy load serving capabilities without local gas resources.

Figure 3.2-90 and Figure 3.2-91 illustrate that load serving capability is higher by retaining some local gas generation that was procured as part of long term procurement plan and those with long-term contract for the LA Basin, some amount of energy storage for the overall area can be accommodated and is limited by the charging capability under the extended transmission contingency condition. Table 3.2-74 provides a summary of the estimated amount of energy storage that can be accommodated from the charging limitation perspective for the sub-areas and the overall LCR area.

Figure 3.2-89 LA Basin LCR area 2025 Peak Day Forecast Profiles

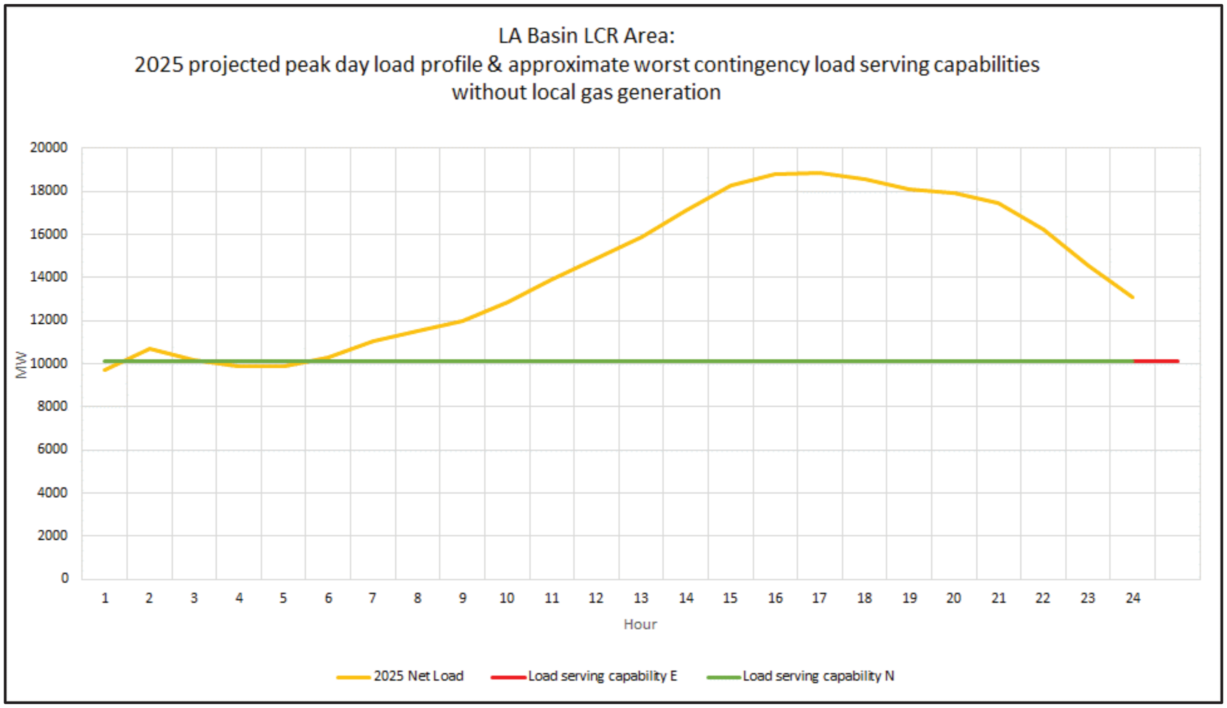


Figure 3.2-90 LA Basin 2025 Peak Day Forecast Profiles with Higher Load Serving Capability

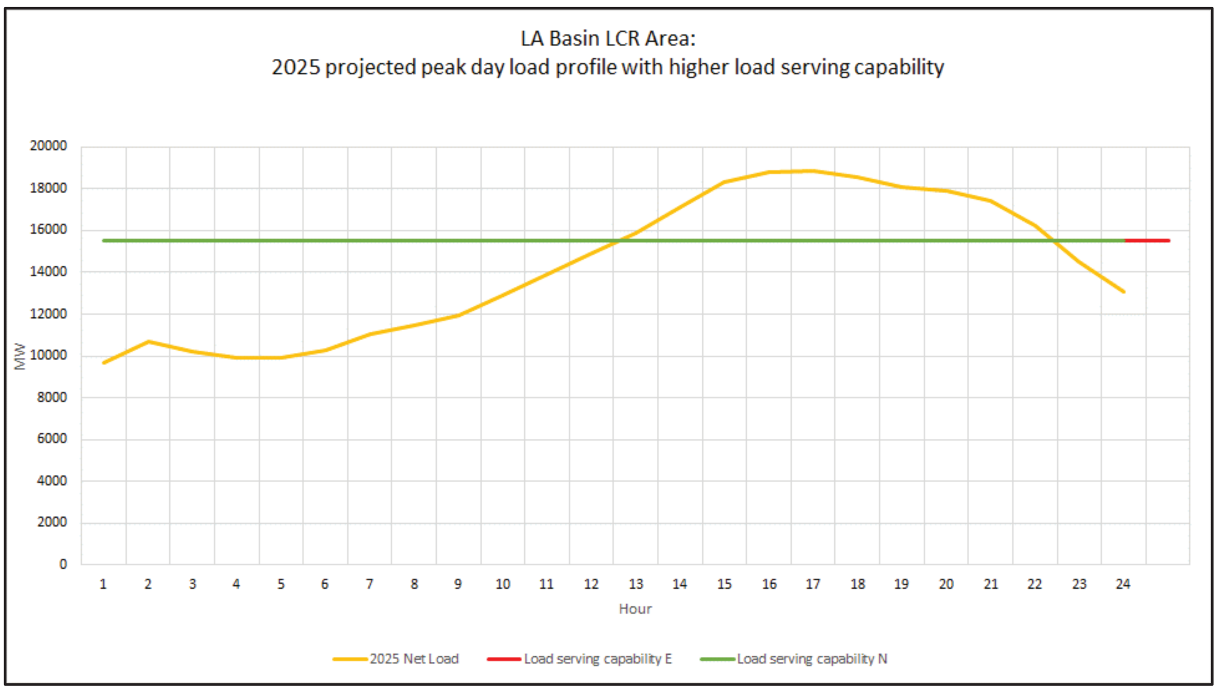
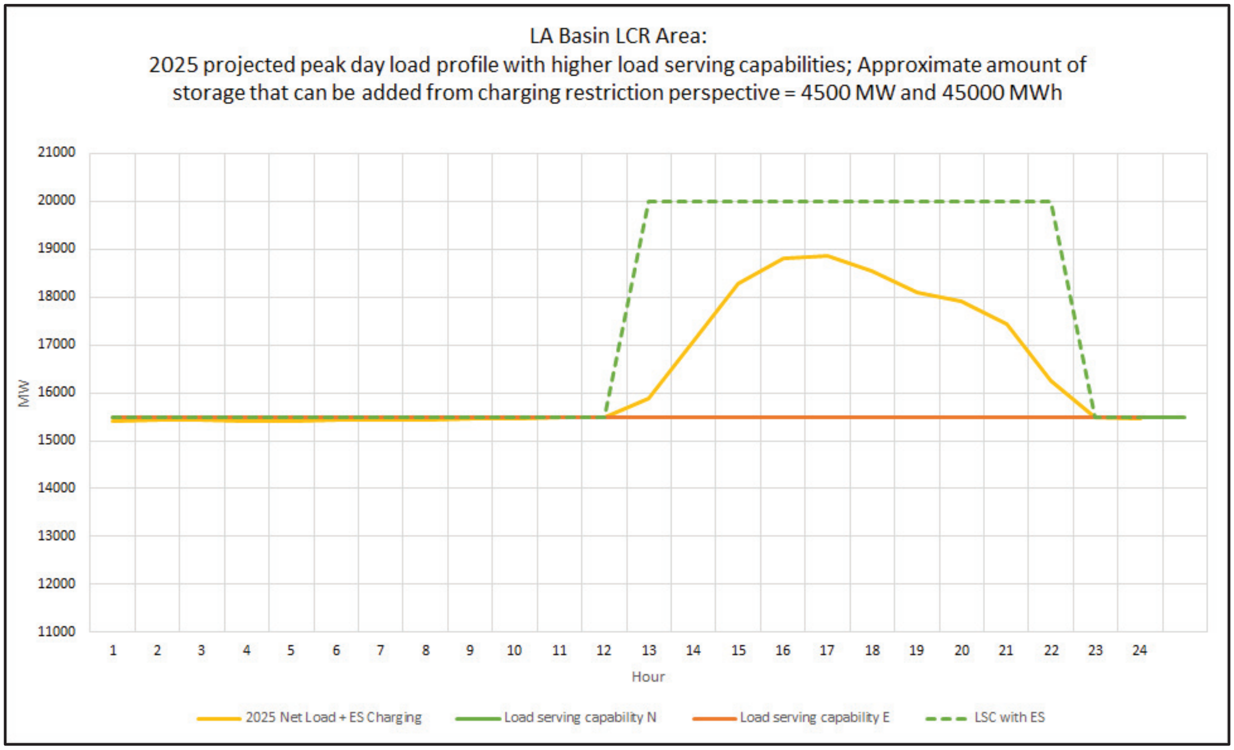


Figure 3.2-91 LA Basin Area 2021 Estimated Amount of Storage that Can Be Added With Higher Load Serving Capability



The following is a summary of estimated amount of storage for the sub-areas and the overall area based on maximum charging capability perspective. Due to non-linearity of power system and the various critical contingencies and load shapes for each sub-area and the overall area, it is noted that the estimated maximum amount of storage for the sub-areas many not add up to be sum of the overall area. The estimated maximum amount of storage for the LCR area is the amount listed in the last row in the table.

Table 3.2-74 Estimated LA Basin Sub-areas and Overall Area Energy Storage Capacity and Energy Based on Maximum Charging Capability Perspective

Area/Sub-area	Estimated Energy Storage Maximum Capacity (MW)	Estimated Energy Storage Maximum Energy (MWh)
El Nido sub-area	250	2000
Western LA Basin sub-area	2700	27000
Eastern LA Basin sub-area	1800	18000
Overall LA Basin Area	4500	45000

3.2.9.8.2 LA Basin LCR area Requirement

Table 3.2-75 identifies the area requirements. The LCR requirement is driven by the sum of the LCR needs for the Western LA Basin and Eastern LA Basin sub-areas, at 6309 MW. Followed closely is the LCR need due to a Category P3 contingency of G-1 of TDM power plant, system readjustment, followed by an outage on the Imperial Valley – North Gila 500 kV line.

Table 3.2-75 LA Basin LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	N/A	Sum of Western and Eastern.		6309
2025	Second Limit	P3	El Centro 230/92 kV	TDM, system readjustment and Imperial Valley–North Gila 500 kV line	6281

3.2.9.8.3 Effectiveness factors:

See Attachment B - Table titled LA Basin.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7550, 7570, 7580, 7590, 7590, 7680 and 7750 posted at: http://www.caiso.com/Documents/2210Z.pdf

There are other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area 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, these effectiveness factors may not be the best indicator towards informed procurement.

3.2.9.8.4 Changes compared to 2024 LCT study

Compared with 2024, the load forecast is lower by 469 MW. The LCR need has increases by 49 MW mostly due to CEC and SCE reallocation of substation loads resulting in a higher amount in Western LA Basin.

3.2.10 San Diego-Imperial Valley Area

3.2.10.1 *Area Definition:*

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

Imperial Valley – North Gila 500 kV Line

Otay Mesa – Tijuana 230 kV Line

San Onofre - San Luis Rey #1 230 kV Line

San Onofre - San Luis Rey #2 230 kV Line

San Onofre - San Luis Rey #3 230 kV Line

San Onofre – Talega 230 kV Line

San Onofre – Capistrano 230 kV Line

Imperial Valley – El Centro 230 kV Line

Imperial Valley – La Rosita 230 kV Line

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

Imperial Valley is in North Gila is out

Otay Mesa is in Tijuana is out

San Onofre is out San Luis Rey is in

San Onofre is out San Luis Rey is in

San Onofre is out San Luis Rey is in

San Onofre is out Talega is in

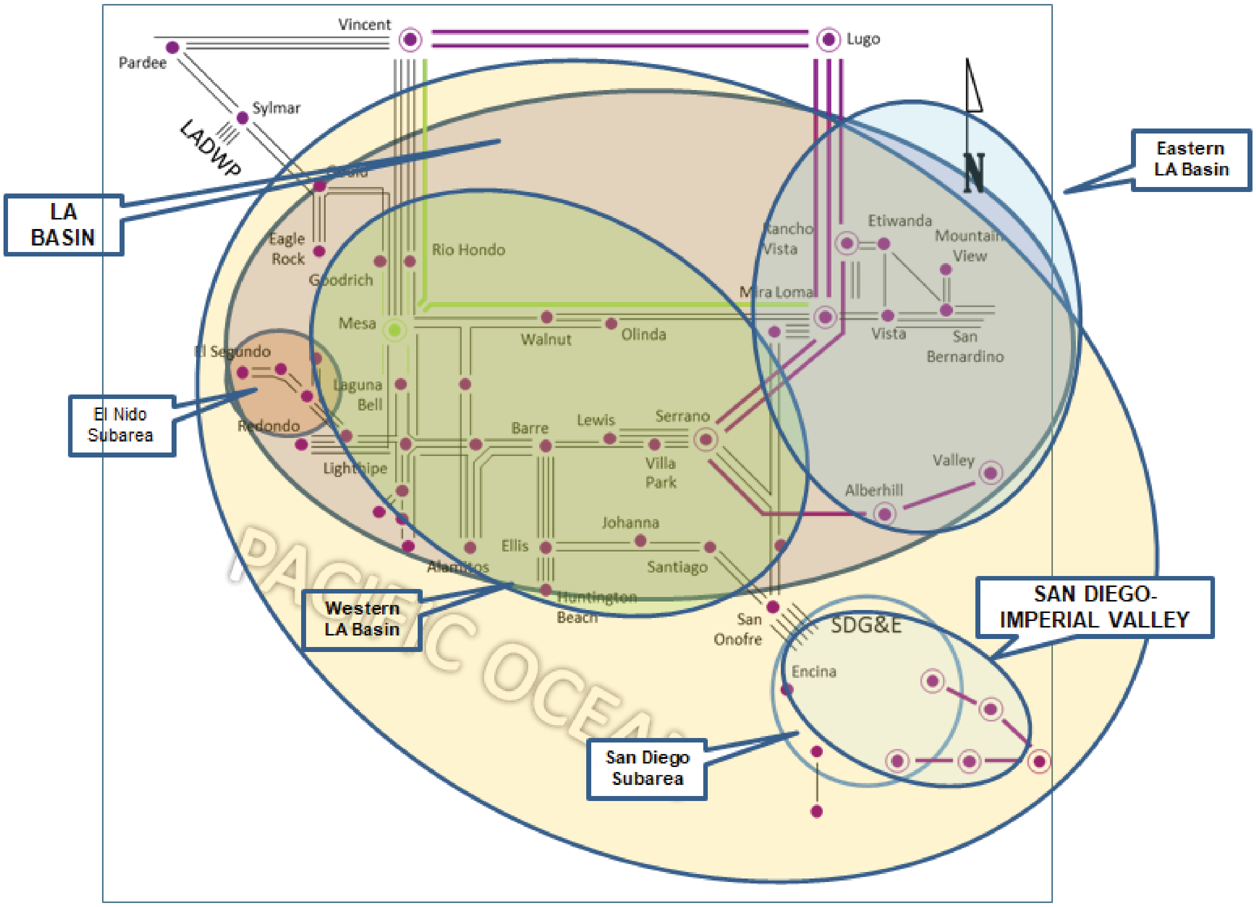
San Onofre is out Capistrano is in

Imperial Valley is in El Centro is out

Imperial Valley is in La Rosita is out

3.2.10.1.1 San Diego-Imperial Valley LCR Area Diagram

Figure 3.2-92 San Diego-Imperial Valley LCR Area



3.2.10.1.2 San Diego-Imperial Valley LCR Area Load and Resources

Table 3.2-76 provides the forecast load and resources in the San Diego-Imperial Valley LCR area in 2025. The list of generators within the LCR area are provided in Attachment A.

In year 2025 the estimated time of local area peak is 8:00 PM on September 3, 2025 per the CEC hourly demand forecast.[12]

At the local area peak time the estimated, ISO metered solar output is 0.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.2-76 San Diego-Imperial Valley LCR Area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4618	Market, Net Seller, Battery, Wind	4431	4431
AAEE	-66	Solar	378	0

[12] https://ww2.energy.ca.gov/2019_energypolicy/documents/Demand_2020-2030_revised_forecast_hourly.php

Behind the meter DG	0	QF	2	2
Net Load	**4552**	LTPP Preferred Resources	0	0
Transmission Losses	123	Existing Demand Response	7	7
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**4675**	**Total**	**4818**	**4440**

3.2.10.1.3 Approved transmission and resource projects modeled:

Ocean Ranch 69 kV substation

Mesa Height TL600 Loop-in

TL6906 Mesa Rim rearrangement

Upgrade Bernardo - Rancho Carmel 69 kV line

Suncrest SVC project

By-passing 500 kV series capacitor banks on the Southwest Powerlink and Sunrise Powerlink lines

Generation retirements at Encina, North Island, Division Naval Station and Otay Landfill

Miramar Energy Storage Project (30 MW)

Storage projects at Melrose (40 MW)

Avocado Energy Storage Project (40 MW)

Second San Marcos–Escondido 69 kV line

Reconductor of Stuart Tap–Las Pulgas 69 kV line (TL690E)

Second Poway–Pomerado 69 kV line

Artesian 230 kV expansion with 69 kV upgrade

South Orange County Reliability Enhancement

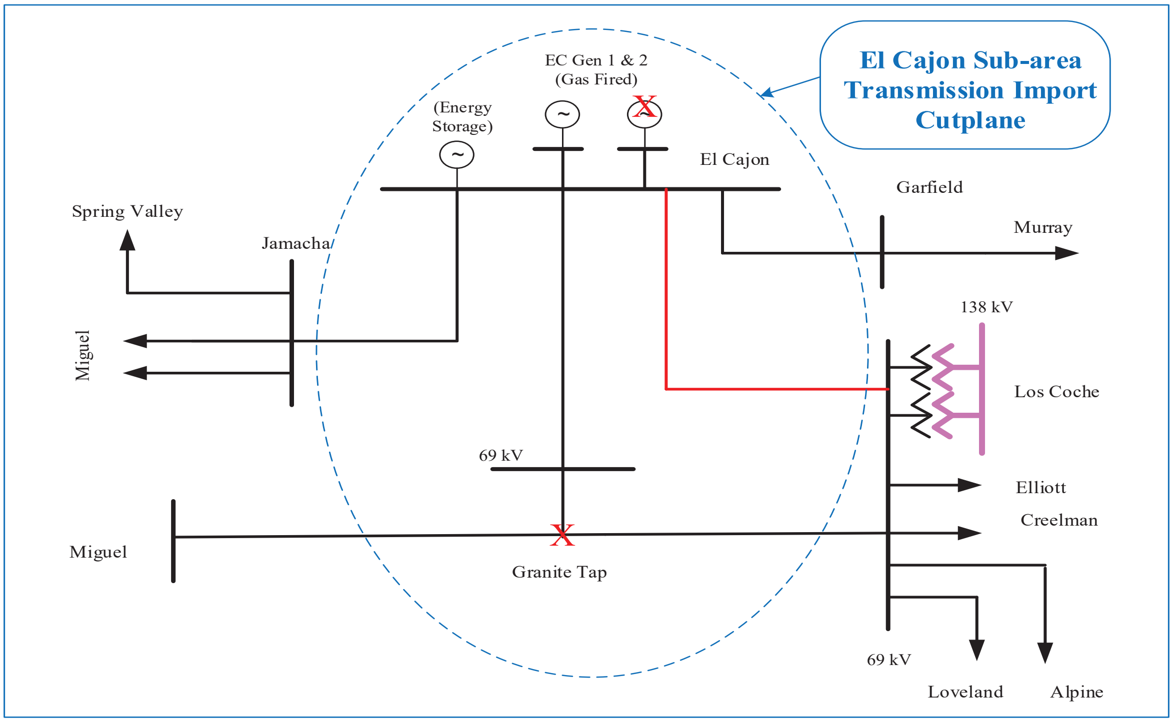
Imperial Valley-El Centro 230 kV (“S”) line upgrade

3.2.10.2 *El Cajon Sub-area*

El Cajon is a Sub-area in the San Diego-Imperial Valley LCR Area.

3.2.10.2.1 El Cajon LCR Sub-area Diagram

Figure 3.2-93 El Cajon LCR Sub-area



3.2.10.2.2 El Cajon LCR Sub-area Load and Resources

Table 3.2-77 provides the forecast load and resources in El Cajon LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-77 El Cajon LCR Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	172	Market, Net Seller, Battery	101	101
AAEE	-3	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**169**	LTPP Preferred Resources	0	0
Transmission Losses	3	Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**172**	**Total**	**101**	**101**

3.2.10.2.3 El Cajon LCR Sub-area Hourly Profiles

Figure 3.2-94 illustrates the 2025 annual load forecast profile in the El Cajon LCR sub-area and the Category P1 (L-1 Contingency) transmission capability without gas generation. Figure 3.2-95 illustrates the 2025 daily load profile forecast for the peak day for the sub-area along with the load serving capabilities. The illustration also includes an estimate of 49/441 MW/MWh energy storage that could be added in this local area from charging restriction perspective, which includes the existing 7.5 MW of energy storage at El Cajon, in order to displace the LCR requirement for gas generation, assuming the biggest energy storage unit is 4/36 MW/MWh.

Figure 3.2-94 El Cajon LCR Sub-area 2025 Annual Load Forecast Profiles

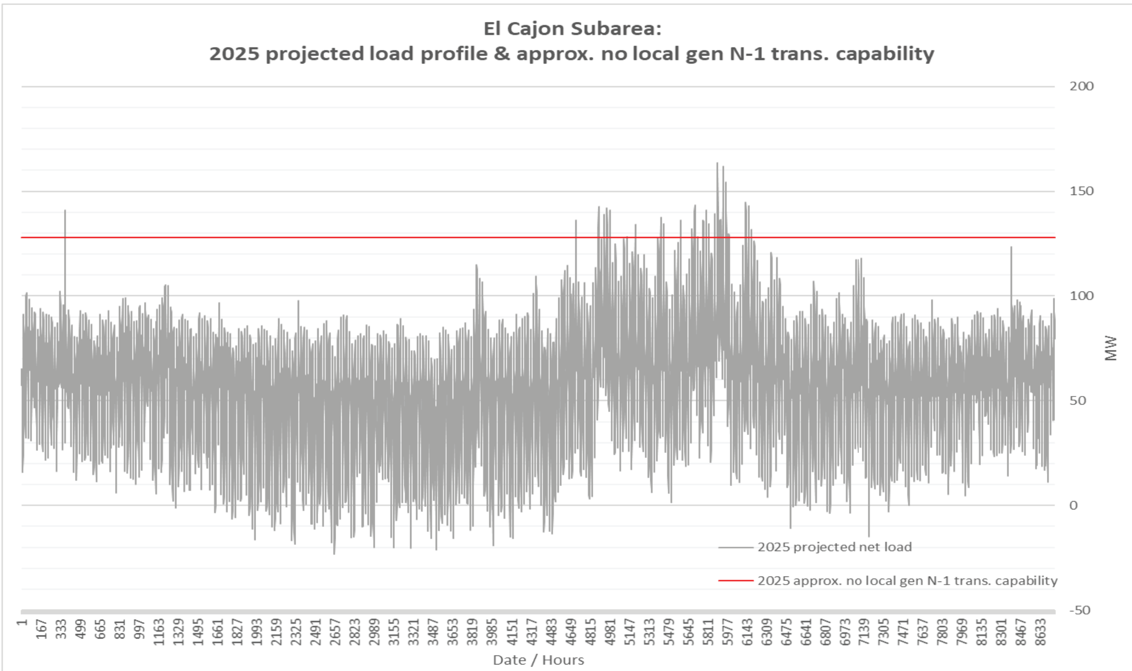
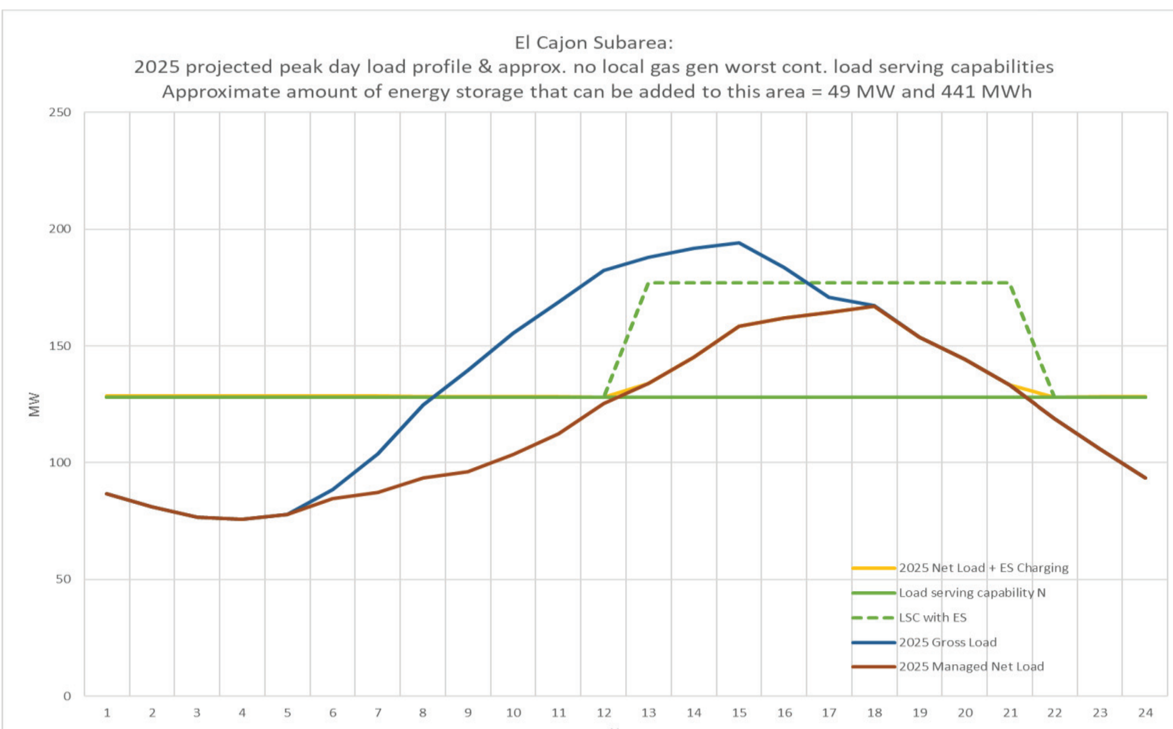


Figure 3.2-95 El Cajon LCR Sub-area 2025 Peak Day Forecast Profiles



3.2.10.2.4 El Cajon LCR Sub-area Requirement

Table 3.2-78 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 99 MW.

Table 3.2-78 El Cajon LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P3	El Cajon–Los Coches 69 kV (TL631)	El Cajon unit out of service followed by Miguel-Granite–Los Coches 69 kV line	99

3.2.10.2.5 Effectiveness factors:

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

3.2.10.3 *Esco Sub-area*

Esco sub-area has been eliminated due to change in LCR criteria.

3.2.10.4 *Pala Inner Sub-area*

Pala Inner sub-area has been eliminated due to change in LCR criteria.

3.2.10.5 *Pala Outer Sub-area*

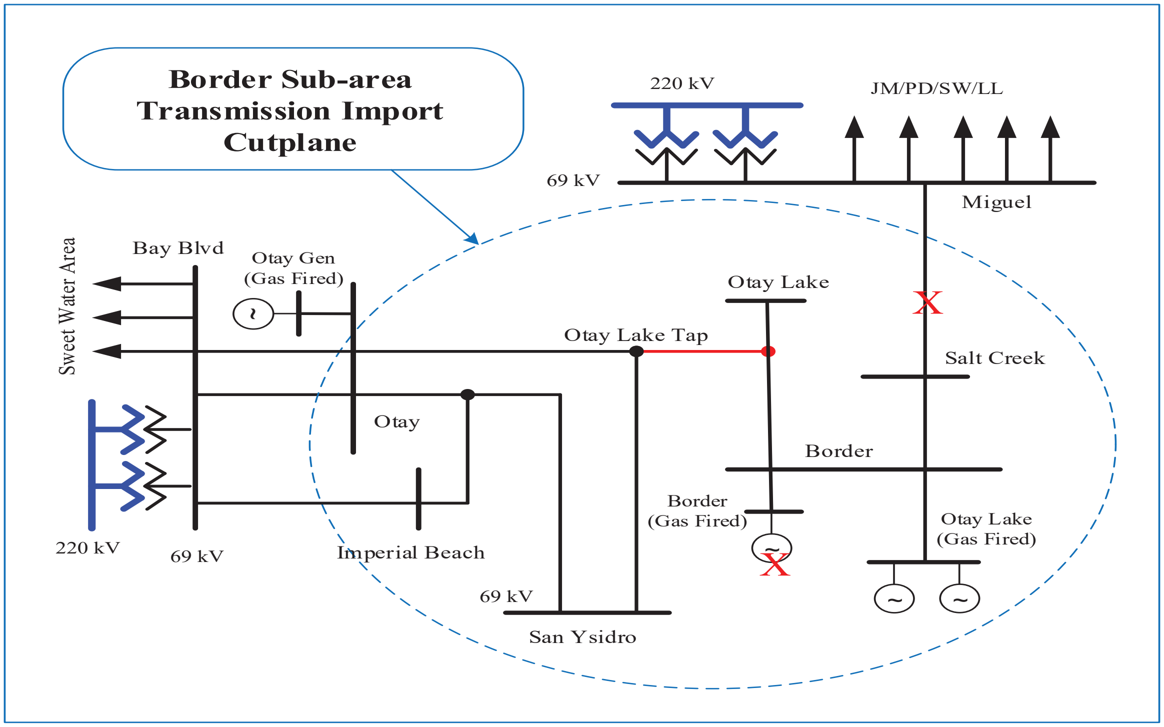
Pala Outer sub-area has been eliminated due to change in LCR criteria.

3.2.10.6 *Border Sub-area*

Border is a Sub-area of the San Diego-Imperial Valley LCR Area.

3.2.10.6.1 Border LCR Sub-area Diagram

Figure 3.2-96 Border LCR Sub-area



3.2.10.6.2 Border LCR Sub-area Load and Resources

Table 3.2-79 provides the forecast load and resources in Border LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.2-79 Border Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	166	Market, Net Seller, Battery	143	143
AAEE	-8	Solar	0	0
Behind the meter DG	0	QF	0	0
Net Load	**158**	LTPP Preferred Resources	0	0
Transmission Losses	2	Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**160**	**Total**	**143**	**143**

3.2.10.6.3 Border LCR Sub-area Hourly Profiles

Figure 3.2-97 illustrates the 2025 annual load forecast profile in the Border LCR sub-area and the Category P1 (L-1 Contingency) transmission capability without gas generation. Figure 3.2-98 illustrates the 2025 daily load forecast profile for the peak day in the sub-area along with the load serving capabilities. The illustration also includes an estimate of 156/775 MW/MWh energy storage that could be added in this local area from charging restriction perspective. In addition, it is estimated that 52/260 MW/MWh energy storage are required to displace the LCR requirement for gas generation, assuming the biggest energy storage unit is 26/130 MW/MWh in the Border LCR sub-area.

Figure 3.2-97 Border LCR Sub-area 2025 Annual Load Forecast Profiles

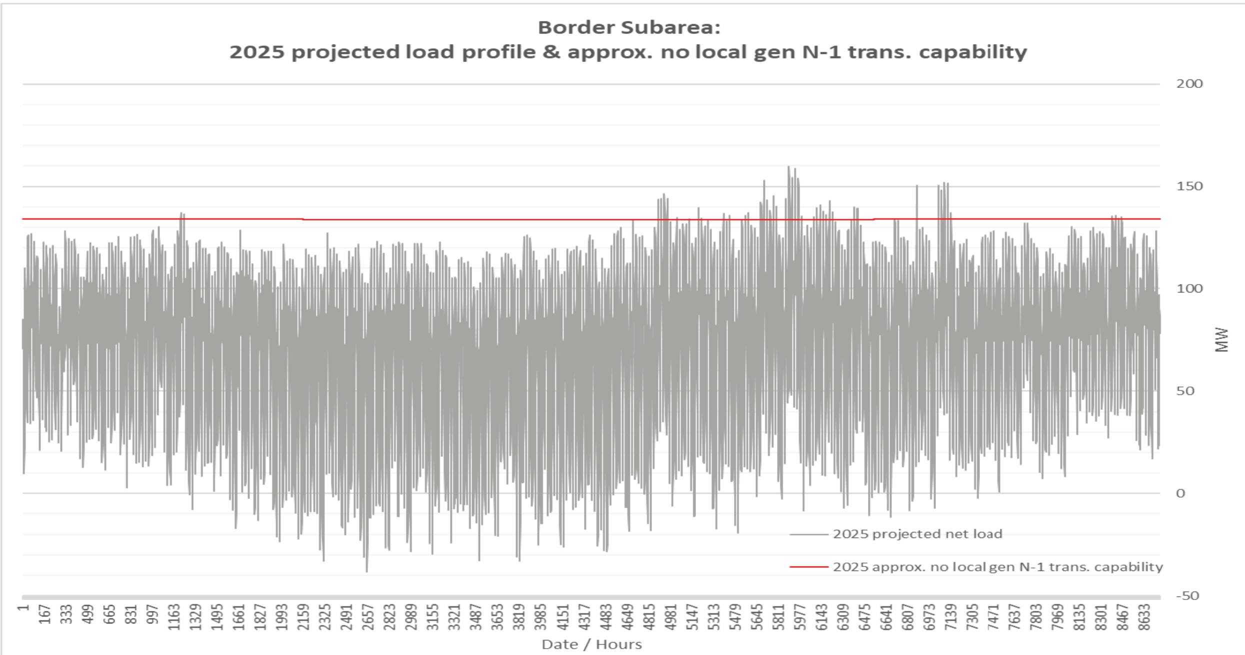
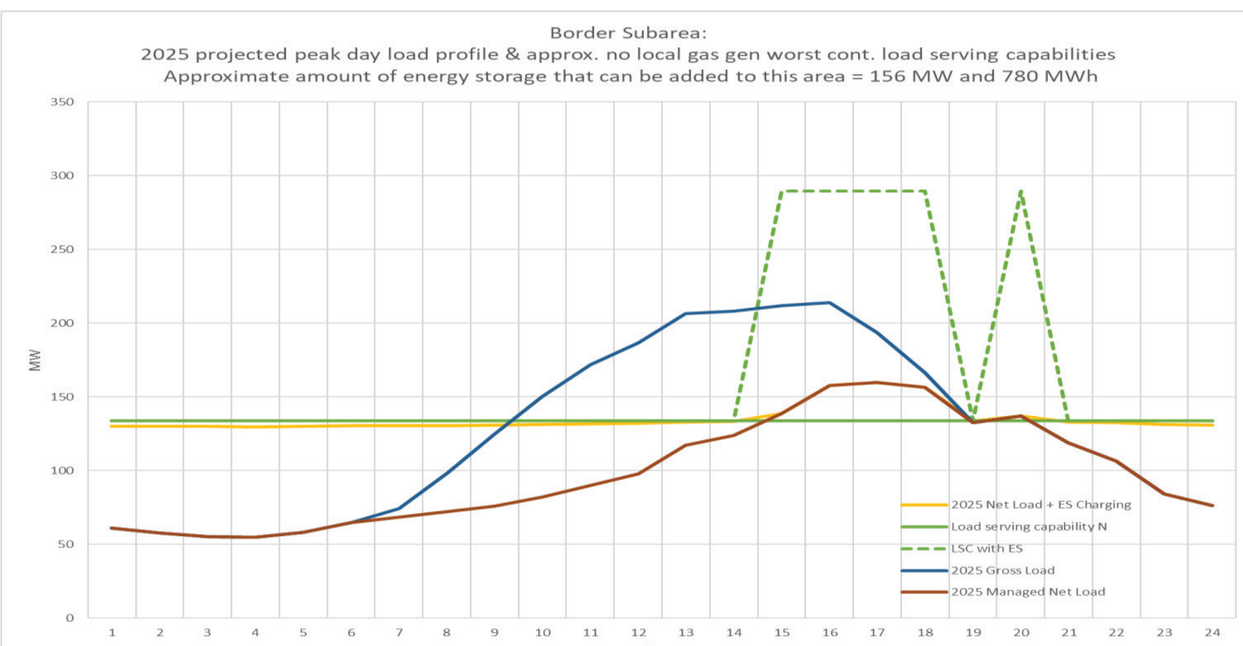


Figure 3.2-98 Border LCR Sub-area 2025 Peak Day Forecast Profiles



3.2.10.6.4 Border LCR Sub-area Requirement

Table 3.2-80 identifies the sub-area requirements. The LCR requirement for Category P3 contingency is 62 MW.

Table 3.2-80 Border 2025 LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P3	Otay – Otay Lake Tap 69 kV (TL649)	Border unit out of service followed by the outage of Miguel-Salt Creek 69 kV #1	62

3.2.10.6.5 Effectiveness factors:

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

3.2.10.7 *San Diego Sub-area*

San Diego is a Sub-area of the San Diego-Imperial Valley LCR Area.

3.2.10.7.1 San Diego LCR Sub-area Diagram

Please refer to Figure 3.2-92 above.

3.2.10.7.2 San Diego LCR Sub-area Load and Resources

Table 3.2-81 provides the forecast load and resources in San Diego LCR sub-area in 2025. The list of generators within the LCR sub-area are provided in Attachment A.

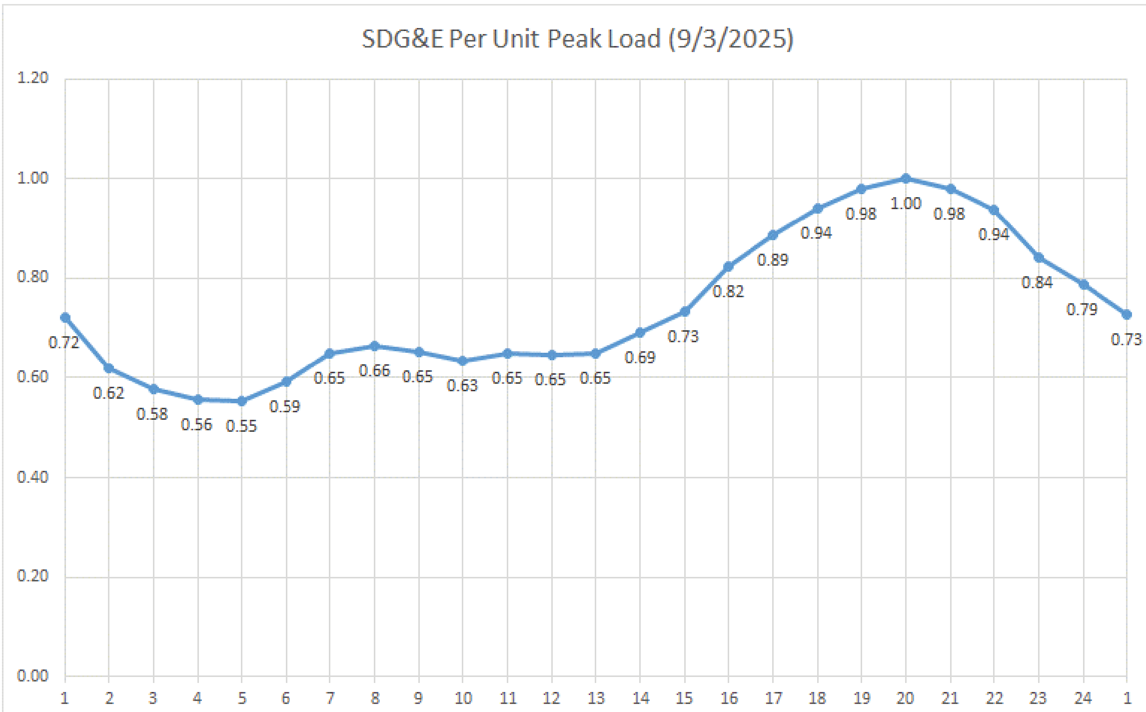
Table 3.2-81 San Diego Sub-area 2025 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4618	Market, Net Seller, Battery, Wind	2987	2987
AAEE	-66	Solar	29	0
Behind the meter DG	0	QF	2	2
Net Load	**4552**	LTPP Preferred Resources	0	0
Transmission Losses	123	Existing Demand Response	7	7
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**4675**	**Total**	**3025**	**2996**

3.2.10.7.3 San Diego LCR Sub-area Hourly Profiles

Figure 3.2-99 illustrates the forecast 2025 profile for the summer peak day for the San Diego LCR sub-area. The plot is from the CEC 2020-2030 Revised Forecast's hourly forecast.[13] Due to the interaction between the overall LA Basin and the San Diego-Imperial Valley areas, the load profile with load serving capability, and the energy storage addition based on its charging capability are evaluated and included for the San Diego-Imperial Valley area.

Figure 3.2-99 San Diego LCR Sub-area 2025 Peak Day Forecast Profiles



3.2.10.7.4 San Diego LCR Sub-area Requirement

Table 3.2-82 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 2791 MW.

Table 3.2-82 San Diego LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P6	Remaining Sycamore – Suncrest 230 kV	Eco – Miguel 500 kV, system readjustment followed by one of the Sycamore – Suncrest 230 kV lines	2791

[13] https://efiling.energy.ca.gov/GetDocument.aspx?tn=231565&DocumentContentId=63386

3.2.10.7.5 Effectiveness factors:

See Attachment B - Table titled San Diego.

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

3.2.10.8 *San Diego-Imperial Valley Overall*

3.2.10.8.1 San Diego-Imperial Valley LCR area Hourly Profiles

Since the San Diego sub-area has all the substation loads, the overall San Diego-Imperial Valley area has the same load profile as the San Diego bulk sub-area. The Imperial Valley area has generating resources. Figure 3.2-100 illustrates the forecast 2025 profile for the summer peak day in the San Diego-Imperial Valley LCR area with the Category P1 normal and emergency load serving capabilities without local gas resources.

Figure 3.2-101 and Figure 3.2-102 illustrate that load serving capability is higher by retaining some local gas generation that was procured as part of long term procurement plan for San Diego local sub-area, some amount of energy storage for the overall area can be accommodated and it is limited by the charging capability under the extended transmission contingency condition. Table 3.2-83 provides a summary of the estimated amount of energy storage that can be accommodated from the charging limitation perspective for the sub-areas and the overall LCR area.

Figure 3.2-100 San Diego-Imperial Valley area 2025 Peak Day Forecast Profiles and Load Serving Capability Without Local Gas Generation

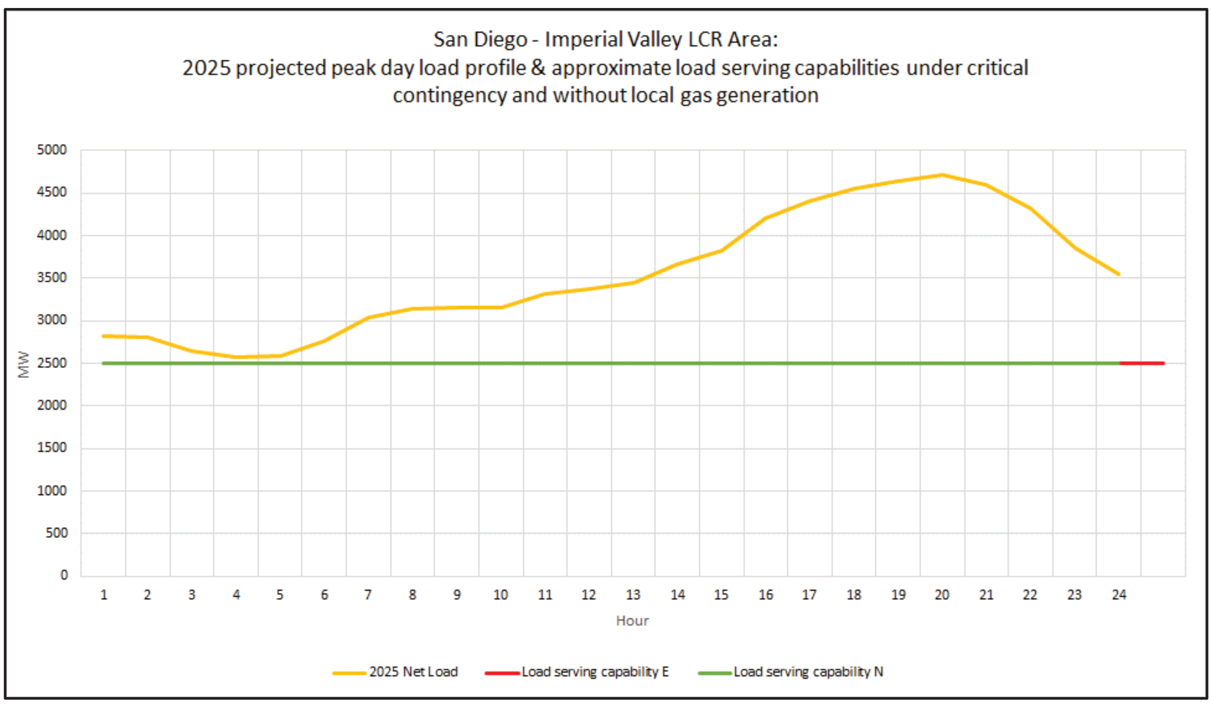


Figure 3.2-101 San Diego-Imperial Valley Area 2025 Peak Day Forecast Profiles with Higher Load Serving Capability

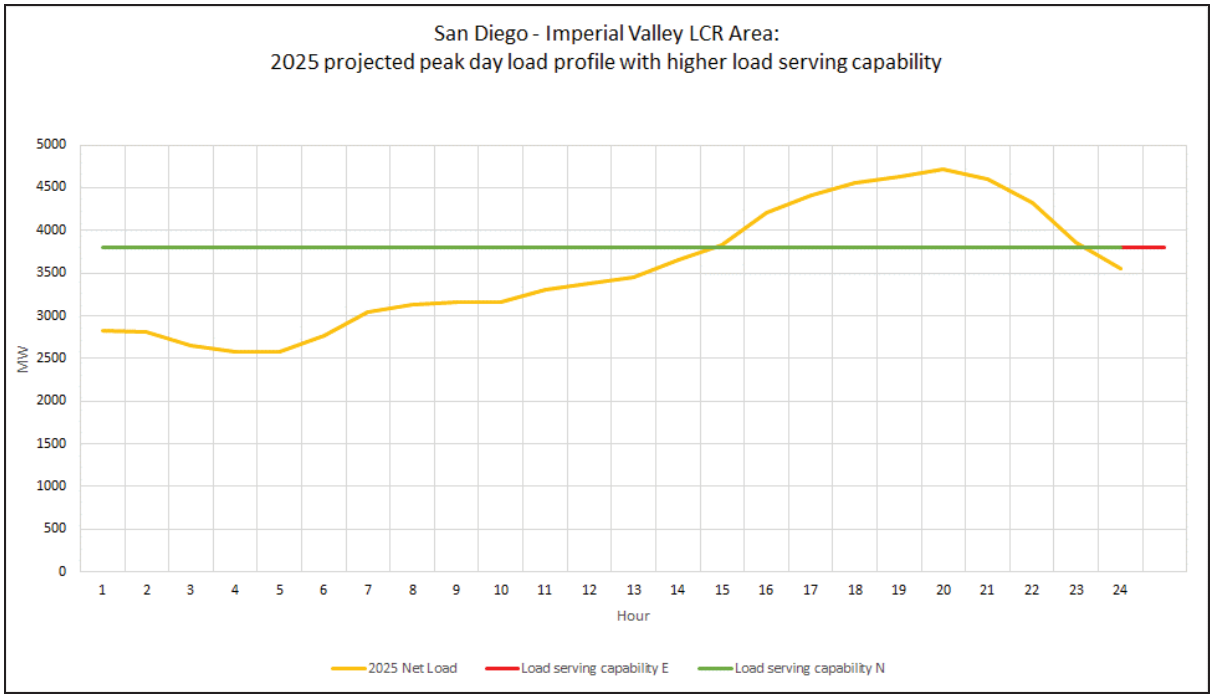
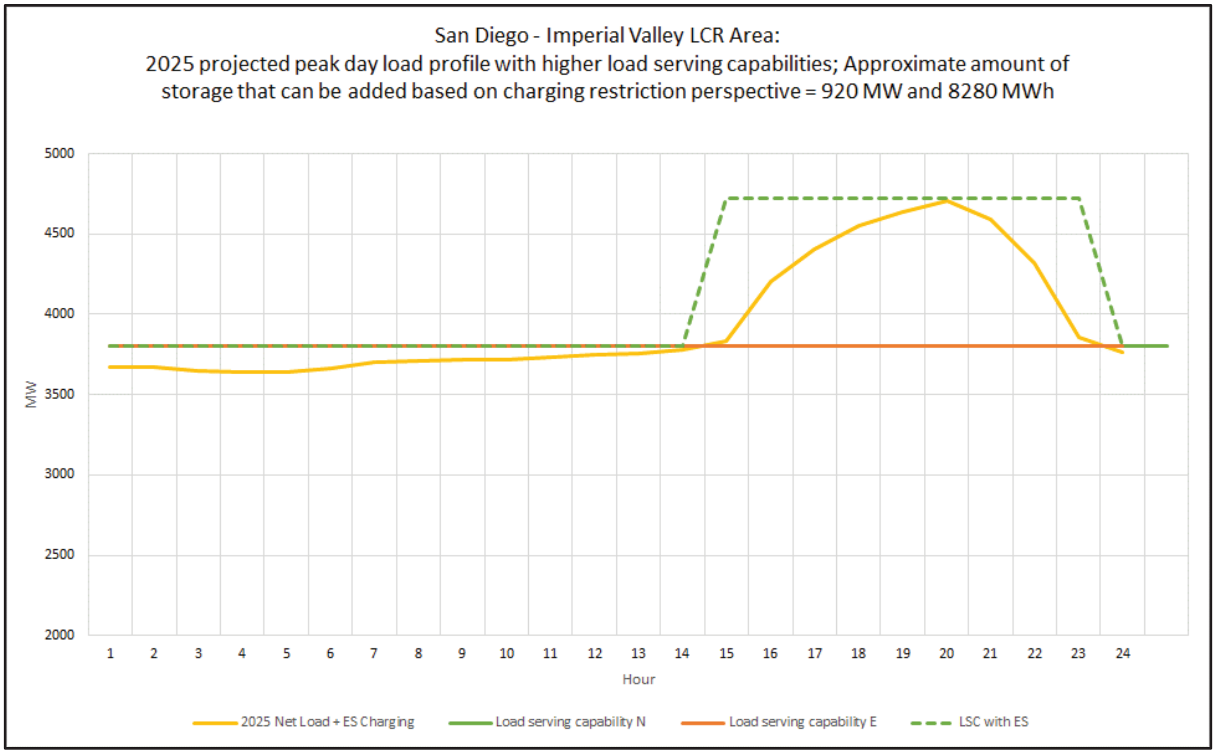


Figure 3.2-102 San Diego-Imperial Valley Area 2025 Estimated Amount of Storage that Can Be Added With Higher Load Serving Capability



The following is a summary of estimated amount of storage for the sub-areas and the overall area based on maximum charging capability perspective. Due to non-linearity of power system and the various critical contingencies and load shapes for each sub-area and the overall area, it is noted that the estimated maximum amount of storage for the sub-areas many not add up to be sum of the overall area. Since the San Diego sub-area has all the substation loads, the overall San Diego-Imperial Valley area has the same load profile as the San Diego bulk sub-area and therefore same amount of energy storage for the San Diego sub-area. The Imperial Valley area (of the overall San Deigo-Imperial Valley) has generating resources only. The estimated maximum amount of storage for the LCR area is the amount listed in the last row in the table.

Table 3.2-83 Estimated San Diego Sub-areas and Overall Area Energy Storage Capacity and Energy Based on Maximum Charging Capability Perspective

Area/Sub-area	Estimated Energy Storage Maximum Capacity (MW)	Estimated Energy Storage Maximum Energy (MWh)
El Cajon sub-area	49	441
Border sub-area	156	780
San Diego bulk sub-area	920	8280
Overall San Diego-Imperial Valley Area	920	8280

3.2.10.8.2 San Diego-Imperial Valley LCR area Requirement

Table 3.2-84 identifies the area LCR requirements. The LCR requirement for Category P6 contingency is 3557 MW.

Table 3.2-84 San Diego-Imperial Valley LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2025	First Limit	P3	El Centro 230/92 kV	TDM power plant, system readjustment and Imperial Valley–North Gila 500 kV line	3557

3.2.10.8.3 Effectiveness factors:

See Attachment B - Table titled San Diego.

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

3.2.10.8.4 Changes compared to 2024 LCT Study

Compared with the 2024 the demand forecast is lower by 130 MW. The overall LCR need for the San Diego – Imperial Valley area has decreased by 468 MW, due to decrease in load forecast and lagelly attributed to modeling of projected new resources (i.e., battery energy storage system) at effective location.

3.2.11 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

Attachment A – List of physical resources by PTO, local area and market ID

PTO	MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR AREA NAME	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
PG&E	ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.40	1	Bay Area	Oakland		MUNI
PG&E	ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	23.50	1	Bay Area	Oakland		MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	1	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	2	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	3	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	4	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	5	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	6	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	7	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	8	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	9	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	10	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	11	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	34.02	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	16.42	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	7.73	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO1	32176	SHILOH	34.5	31.50	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	31.50	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	21.53	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	21.00	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.56	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	190.00	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG2	33188	MARSHCT2	16.4	189.21	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG3	33189	MARSHCT3	16.4	188.50	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG4	33189	MARSHCT4	16.4	189.89	4	Bay Area	Contra Costa	Aug NQC	Market

PG&E	COCOSB_6_SOLAR				0.00		Bay Area	Contra Costa	Not modeled Energy Only	Solar
PG&E	CROKET_7_UNIT	32900	CRCKTCOG	18	211.49	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	5.13	1	Bay Area	Pittsburg	Aug NQC	Solar
PG&E	DELTA_2_PL1X4	33107	DEC STG1	24	269.60	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	DIXNLD_1_LNDFL				0.64		Bay Area		Not modeled Aug NQC	Market
PG&E	DUANE_1_PL1X3	36863	DVRaGT1	13.8	48.27	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36864	DVRbGT2	13.8	48.27	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36865	DVRaST3	13.8	46.96	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	GATWAY_2_PL1X3	33118	GATEWAY1	18	180.78	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33119	GATEWAY2	18	171.17	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33120	GATEWAY3	18	171.17	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	69.00	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	36.00	2	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35851	GROYPKR1	13.8	47.60	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35852	GROYPKR2	13.8	47.60	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market

PG&E	GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.20	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GRZZLY_1_BERKLY	32741	HILLSIDE_12	12.5	14.67	1	Bay Area		Aug NQC	Net Seller
PG&E	KELSO_2_UNITS	33813	MARIPCT1	13.8	48.09	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33815	MARIPCT2	13.8	48.09	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33817	MARIPCT3	13.8	48.09	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33819	MARIPCT4	13.8	48.09	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				0.17		Bay Area		Not modeled Aug NQC	Market
PG&E	LECEF_1_UNITS	35858	LECEFST1	13.8	111.58	1	Bay Area	San Jose, South Bay-Moss Landing		Market
PG&E	LECEF_1_UNITS	35854	LECEFGT1	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35855	LECEFGT2	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35856	LECEFGT3	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35857	LECEFGT4	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.50	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	47.60	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.40	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33113	LMECST1	18	243.71	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33111	LMECCT2	18	165.41	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33112	LMECCT1	18	165.41	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	MARTIN_1_SUNSET				1.22		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	METEC_2_PL1X3	35883	MEC STG1	18	213.13	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	MISSIX_1_QF				0.01		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	MLPTAS_7_QFUNTS				0.00		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	36223	DUKMOSS3	18	183.60	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36221	DUKMOSS1	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36222	DUKMOSS2	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36226	DUKMOSS6	18	183.60	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36224	DUKMOSS4	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36225	DUKMOSS5	18	163.20	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	NEWARK_1_QF				0.05		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	OAK C_1_EBMUD				1.20		Bay Area	Oakland	Not modeled Aug NQC	MUNI
PG&E	OAK C_7_UNIT 1	32901	OAKLND 1	13.8	0.00	1	Bay Area	Oakland	Retired by 2025	Market
PG&E	OAK C_7_UNIT 2	32902	OAKLND 2	13.8	0.00	1	Bay Area	Oakland	Retired by 2025	Market
PG&E	OAK C_7_UNIT 3	32903	OAKLND 3	13.8	0.00	1	Bay Area	Oakland	Retired by 2021	Market
PG&E	OAK L_1_GTG1				0.00		Bay Area	Oakland	Not modeled Energy Only	Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	1	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	2	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	3	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	4	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	5	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	6	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.47	7	Bay Area	Ames		Market
PG&E	PALALT_7_COBUG				4.50		Bay Area		Not modeled	MUNI
PG&E	RICHMN_1_CHVSR2				2.30		Bay Area		Not modeled Aug NQC	Solar
PG&E	RICHMN_1_SOLAR				0.54		Bay Area		Not modeled Aug NQC	Solar
PG&E	RICHMN_7_BAYENV				2.00		Bay Area		Not modeled Aug NQC	Market

PG&E	RUSCTY_2_UNITS	35306	RUSELST1	15	237.09	3	Bay Area	Ames	No NQC - Pmax	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	RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	47.60	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	SHELRF_1_UNITS	33142	SHELL 2	12.5	10.91	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SHELRF_1_UNITS	33143	SHELL 3	12.5	10.91	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SHELRF_1_UNITS	33141	SHELL 1	12.5	5.88	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SRINTL_6_UNIT	33468	SRI INTL	9.11	0.78	1	Bay Area		Aug NQC	QF/Selfgen
PG&E	STAUFF_1_UNIT	33139	STAUFER	9.11	0.01	1	Bay Area		Aug NQC	QF/Selfgen
PG&E	STOILS_1_UNITS	32921	CHEVGEN1	13.8	2.09	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32922	CHEVGEN2	13.8	2.09	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32923	CHEVGEN3	13.8	0.97	3	Bay Area	Pittsburg	Aug NQC	Market
PG&E	SWIFT_1_NAS	35623	SWIFT	21	3.00	BT	Bay Area	San Jose, South Bay-Moss Landing		Battery
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.05	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.05	2	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	3.08	3	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	UNCHEM_1_UNIT	32920	UNION CH	9.11	13.10	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.02	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.02	2	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.02	3	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	USWNDR_2_LABWD1				1.89		Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD	365574	SOLANO2W		18.24	2	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD	365566	SOLANO1W		3.22	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD2	365600	SOLANO3W		26.84	3	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWPJR_2_UNITS	39233	GRNRDG	0.69	16.42	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	7.98	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZOND_6_UNIT	35316	ZOND SYS	9.11	3.59	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_MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	Bay Area	San Jose, South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_NA	35861	SJ-SCL W	4.3	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen

PG&E	ZZ_NA	36209	SLD ENRG	12.5	0.00	1	Bay Area	South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_SEAWST_6_LAPOS	35312	FOREBAYW	22	0.00	1	Bay Area	Contra Costa	No NQC - est. data	Wind
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	1.90	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	0.00	2	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_ZANKER_1_UNIT 1	35861	SJ-SCL W	4.3	0.00	RN	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	30045	MOSSLAND	500	300.00	ES	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	30755	MOSSLNSW	230	182.50	ES	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	35646	MRGN HIL	115	75.00	ES	Bay Area	San Jose, South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	30522	0354-WD	21	1.83	EW	Bay Area	Contra Costa	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	365540	Q1016		0.00	1	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	32741	HILLSIDE		0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	365559	STANFORD		0.00	RN	Bay Area		Energy Only	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	ZZZ_New Unit	35307	A100US-L	12.6	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZZ_New Unit	32786	OAK C115	115	10.00	ES	Bay Area	Oakland	OCEI	Battery
PG&E	ZZZZ_New Unit	32908	OAK C12	12	2.50	ES	Bay Area	Oakland	OCEI	Battery
PG&E	ZZZZ_New Unit	32788	STTIN L	115	2.50	ES	Bay Area	Oakland	OCEI	Battery
PG&E	ZZZZZ_METCLF_1_QF				0.00		Bay Area		Retired	QF/Selfgen
PG&E	ZZZZZ_USWNDR_2_UNITS	32168	EXNCO	9.11	0.00	1	Bay Area	Contra Costa	Retired	Wind
PG&E	ZZZZZZ_COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_CONTAN_1_UNIT	36856	CCA100	13.8	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	Retired	MUNI
PG&E	ZZZZZZ_FLOWD1_6_ALTPP 1	35318	FLOWDPTR	9.11	0.00	1	Bay Area	Contra Costa	Retired	Wind
PG&E	ZZZZZZ_LFC 51_2_UNIT 1	35310	PPASSWND	21	0.00	1	Bay Area		Retired	Wind

PG&E	ZZZZZZ_MOSSLD_7_UNIT 6	36405	MOSSLND6	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market
PG&E	ZZZZZZ_MOSSLD_7_UNIT 7	36406	MOSSLND7	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 5	33105	PTSB 5	18	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	Bay Area		Retired	QF/Selfgen
PG&E	ADERA_1_SOLAR1	34319	CHWCHLAS	0.48	0.00	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Energy Only	Solar
PG&E	ADMEST_6_SOLAR	34315	ADAMS_E	12.5	0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	AGRICO_6_PL3N5	34608	AGRICO	13.8	22.69	3	Fresno	Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	43.13	4	Fresno	Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	7.47	2	Fresno	Herndon		Market
PG&E	AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	AVENAL_6_AVSLR1	34691	AVENAL_1	21	0.00	EW	Fresno	Coalinga	Energy Only	Solar
PG&E	AVENAL_6_AVSLR2	34691	AVENAL_1	21	0.00	EW	Fresno	Coalinga	Energy Only	Solar
PG&E	AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	BALCHS_7_UNIT 1	34624	BALCH	13.2	31.00	1	Fresno	Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Fresno	Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 3	34614	BLCH	13.8	54.60	1	Fresno	Herndon	Aug NQC	Market
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	2.70	1	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	2.70	2	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	2.09	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	QF/Selfgen
PG&E	CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.85	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	QF/Selfgen
PG&E	CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	9.30	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV		Market

PG&E	CORCAN_1_SOLAR1	34690	CORCORAN	12.5	5.40	FW	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	CORCAN_1_SOLAR2	34692	CORCORAN	12.5	2.97	FW	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	CRESSY_1_PARKER	34140	CRESSEY	115	1.29		Fresno		Not modeled Aug NQC	MUNI
PG&E	CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.00	1	Fresno	Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	0.01	1	Fresno	Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	0.00	1	Fresno	Borden	Aug NQC	Market
PG&E	CURTIS_1_CANLCK				0.00		Fresno		Not modeled Aug NQC	Market
PG&E	CURTIS_1_FARFLD				0.47		Fresno		Not modeled Aug NQC	Market
PG&E	DAIRLD_1_MD1SL1				0.00		Fresno		Energy Only	Solar
PG&E	DAIRLD_1_MD2BM1				0.00		Fresno		Energy Only	Market
PG&E	DINUBA_6_UNIT	34648	DINUBA E	13.8	0.00	1	Fresno	Herndon, Reedley	Mothballed	Market
PG&E	EEKTMN_6_SOLAR1	34629	KETTLEMN	0.8	0.00	1	Fresno		Energy Only	Solar
PG&E	ELCAP_1_SOLAR				0.00		Fresno		Not Modeled Aug NQC	Solar
PG&E	ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	9.59	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	90.72	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	MUNI
PG&E	EXCLSG_1_SOLAR	34623	Q678	0.5	16.20	1	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	FRESHW_1_SOLAR1	34699	Q529	0.39	0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	8.56	2	Fresno	Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	4.57	3	Fresno	Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.21	4	Fresno	Borden	Aug NQC	Net Seller
PG&E	GIFENS_6_BUGSL1	34644	Q679	0.55	5.40	1	Fresno		Aug NQC	Solar
PG&E	GIFFEN_6_SOLAR	34467	GIFFEN_DIST	12.5	2.70	1	Fresno	Herndon	Aug NQC	Solar
PG&E	GIFFEN_6_SOLAR1				0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	GUERNS_6_SOLAR	34463	GUERNSEY_D 2	12.5	2.70	5	Fresno		Aug NQC	Solar
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY_D 1	12.5	2.70	8	Fresno		Aug NQC	Solar
PG&E	GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	45.30	1	Fresno	Herndon, Hanford		Market
PG&E	GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	45.30	1	Fresno	Herndon, Hanford		Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	1	Fresno	Herndon	Aug NQC	Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	2	Fresno	Herndon	Aug NQC	Market
PG&E	HELMPG_7_UNIT 1	34600	HELMS	18	407.00	1	Fresno		Aug NQC	Market
PG&E	HELMPG_7_UNIT 2	34602	HELMS	18	407.00	2	Fresno		Aug NQC	Market
PG&E	HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Fresno		Aug NQC	Market

PG&E	HENRTA_6_SOLAR1				0.00		Fresno		Not modeled Aug NQC	Solar
PG&E	HENRTA_6_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	HENRTA_6_UNITA1	34539	GWF_GT1	13.8	44.99	1	Fresno			Market
PG&E	HENRTA_6_UNITA2	34541	GWF_GT2	13.8	44.89	1	Fresno			Market
PG&E	HENRTS_1_SOLAR	34617	Q581	0.38	27.00	1	Fresno	Herndon	Aug NQC	Solar
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	2.70	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	2.70	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	JAYNE_6_WLSLR	34639	WESTLNDS	0.48	0.00	1	Fresno	Coalinga	Energy Only	Solar
PG&E	KANSAS_6_SOLAR	34666	KANSASS_S	12.5	0.00	F	Fresno		Energy Only	Solar
PG&E	KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERMAN_6_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KERMAN_6_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KINGCO_1_KINGBR	34642	KINGSBUR	9.11	34.50	1	Fresno	Herndon, Hanford	Aug NQC	Net Seller
PG&E	KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Fresno	Herndon, Reedley	Aug NQC	Market
PG&E	KNGBRG_1_KBSLR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KNGBRG_1_KBSLR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Fresno		Energy Only	Solar
PG&E	LEPRFD_1_KANSAS	34680	KANSAS	12.5	5.40	1	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Fresno	Herndon		Market
PG&E	MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Fresno	Herndon		Market
PG&E	MCCALL_1_QF	34219	MCCALL 4	12.5	0.65	QF	Fresno	Herndon	Aug NQC	QF/Selfgen
PG&E	MCSWAN_6_UNITS	34320	MCSWAIN	9.11	9.60	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	MUNI
PG&E	MENBIO_6_RENEW1	34339	CALRENEW	12.5	1.35	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Aug NQC	Net Seller

PG&E	MERCED_1_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MERCED_1_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MERCFL_6_UNIT	34322	MERCEDFL	9.11	3.36	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR1	34313	NORTHSTA	0.2	16.20	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Solar
PG&E	MNDOTA_1_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MSTANG_2_SOLAR	34683	Q643W	0.8	8.10	1	Fresno		Aug NQC	Solar
PG&E	MSTANG_2_SOLAR3	34683	Q643W	0.8	10.80	1	Fresno		Aug NQC	Solar
PG&E	MSTANG_2_SOLAR4	34683	Q643W	0.8	8.10	1	Fresno		Aug NQC	Solar
PG&E	ONLLPP_6_UNITS	34316	ONEILPMP	9.11	12.12	1	Fresno		Aug NQC	MUNI
PG&E	OROLOM_1_SOLAR1	34689	ORO LOMA_3	12.5	0.00	EW	Fresno	Panoche 115 kV	Energy Only	Solar
PG&E	OROLOM_1_SOLAR2	34689	ORO LOMA_3	12.5	0.00	EW	Fresno	Panoche 115 kV	Energy Only	Solar
PG&E	ORTGA_6_ME1SL1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	PAIGES_6_SOLAR	34653	Q526	0.55	0.00	1	Fresno	Coalinga, Panoche 115 kV	Energy Only	Solar
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	1	Fresno	Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	2	Fresno	Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	3	Fresno	Herndon	Aug NQC	MUNI
PG&E	PNCHPP_1_PL1X2	34328	STARGT1	13.8	54.18	1	Fresno	Panoche 115 kV		Market
PG&E	PNCHPP_1_PL1X2	34329	STARGT2	13.8	54.18	2	Fresno	Panoche 115 kV		Market
PG&E	PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Fresno	Herndon, Panoche 115 kV		Market
PG&E	PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	52.01	1	Fresno	Panoche 115 kV		Market
PG&E	REEDLY_6_SOLAR				0.00		Fresno	Herndon, Reedley	Not modeled Energy Only	Solar
PG&E	S_RITA_6_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	2.70	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	1.35	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_OS2BM2				0.00		Fresno	Coalinga	Energy Only	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	2.70	3	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar

PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	1.35	4	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	38.77	1	Fresno	Herndon	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	9.31	2	Fresno	Herndon	Aug NQC	Market
PG&E	STOREY_2_MDRCH2	34253	BORDEN D	12.5	0.28		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH3	34253	BORDEN D	12.5	0.19		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH4	34253	BORDEN D	12.5	0.20		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_7_MDRCHW	34209	STOREY D	12.5	0.82	1	Fresno		Aug NQC	Net Seller
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.70	1	Fresno	Herndon	Aug NQC	Solar
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.70	2	Fresno	Herndon	Aug NQC	Solar
PG&E	STROUD_6_WWHSR1				0.00		Fresno	Herndon	Energy Only	Solar
PG&E	SUMWHT_6_SWSSR1				5.00		Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_AMASR1	365514	Q1032G1	0.55	5.40	1	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_AZUSR1	365517	Q1032G2	0.55	5.40	2	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_ROJSR1	365520	Q1032G3	0.55	8.10	3	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_VERSR1	365520	Q1032G3	0.55	0.00	3	Fresno		Aug NQC	Solar
PG&E	TRNQLT_2_SOLAR	34340	Q643X	0.8	54.00	1	Fresno		Aug NQC	Solar
PG&E	ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	24.07	1	Fresno	Herndon	Aug NQC	Market
PG&E	VEGA_6_SOLAR1	34314	VEGA	34.5	0.00	1	Fresno		Energy Only	Solar
PG&E	WAUKNA_1_SOLAR	34696	CORCORANPV_S	21	5.40	1	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	WAUKNA_1_SOLAR2	34677	Q558	21	5.33	1	Fresno	Herndon, Hanford	No NQC - Pmax	Solar
PG&E	WFRESN_1_SOLAR				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	WHITNY_6_SOLAR	34673	Q532	0.55	0.00	1	Fresno	Coalinga, Panoche 115 kV	Energy Only	Solar
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	0.36	SJ	Fresno	Borden	Aug NQC	Market
PG&E	WOODWR_1_HYDRO				0.00		Fresno		Not modeled Energy Only	Market
PG&E	WRGHTP_7_AMENGY	34207	WRIGHT D	12.5	0.53	QF	Fresno		Aug NQC	QF/Selfgen

PG&E	ZZ_BORDEN_2_QF	34253	BORDEN D	12.5	1.30	QF	Fresno		No NQC - hist. data	Net Seller
PG&E	ZZ_BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.06	1	Fresno	Herndon	Aug NQC	QF/Selfgen
PG&E	ZZ_JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	0.00	1	Fresno			QF/Selfgen
PG&E	ZZ_KERKH1_7_UNIT 2	34343	KERCK1-2	6.6	8.50	2	Fresno	Herndon, Wilson 115 kV	No NQC - hist. data	Market
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.10	2	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	1	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	3	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_New Unit	34651	JACALITO-LV	0.55	1.22	RN	Fresno		No NQC - Pmax	Market
PG&E	ZZZ_New Unit	365697	Q1158B	0.36	300.00	1	Fresno		No NQC - est. data	Battery
PG&E	ZZZ_New Unit	365524	Q1036SPV	0.36	41.42	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34688	Q272	0.36	33.21	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365675	Q1128-5S	0.36	13.50	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365673	Q1128-4S	0.36	13.50	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34335	Q723	0.32	13.50	1	Fresno	Borden	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365604	Q1028Q10	0.36	5.40	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365663	Q1127SPV	0.36	5.40	1	Fresno	Panoche 115 kV, Wilson 115 kV	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365504	Q632BSPV	0.55	5.00	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34649	Q965SPV	0.36	3.65	1	Fresno	Herndon	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365694	Q1158S	0.36	0.00	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34603	JGBSWLT	12.5	0.00	ST	Fresno	Herndon	Energy Only	Market
PG&E	ZZZZZ_CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	0.00	RT	Fresno		Retired	Market

PG&E	ZZZZZ_COLGA1_6_SHELLW	34654	COLNGAGN	9.11	0.00	1	Fresno	Coalinga	Retired	Net Seller
PG&E	ZZZZZ_GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	RT	Fresno	Coalinga	Retired	Market
PG&E	ZZZZZ_INTTRB_6_UNIT	34342	INT.TURB	9.11	0.00	1	Fresno		Retired	Market
PG&E	ZZZZZ_MENBIO_6_UNIT	34334	BIO PWR	9.11	0.00	1	Fresno	Panoche 115 kV, Wilson 115 kV	Retired	QF/Selfgen
PG&E	BRDGVL_7_BAKER				0.00		Humboldt		Not modeled Aug NQC	Net Seller
PG&E	FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	12.65	1	Humboldt		Aug NQC	Net Seller
PG&E	FTSWRD_6_TRFORK				0.15		Humboldt		Not modeled Aug NQC	Market
PG&E	FTSWRD_7_QFUNTS				0.00		Humboldt		Not modeled Aug NQC	QF/Selfgen
PG&E	GRSCRK_6_BGCKWW				0.00		Humboldt		Not modeled Aug NQC	Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.69	3	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.32	1	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.22	4	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	15.85	2	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.62	8	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.33	6	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.33	9	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.24	7	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.14	5	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	15.95	10	Humboldt			Market
PG&E	HUMBSB_1_QF				0.00		Humboldt		Not modeled Aug NQC	QF/Selfgen
PG&E	KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt		Aug NQC	Net Seller
PG&E	LAPAC_6_UNIT	31158	LP SAMOA	12.5	0.00	1	Humboldt			Market
PG&E	LOWGAP_1_SUPHR				0.00		Humboldt		Not modeled Aug NQC	Market
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	5.82	1	Humboldt		Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	5.82	2	Humboldt		Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31153	PAC.LUMB	2.4	3.49	3	Humboldt		Aug NQC	Net Seller
PG&E	ZZZZZ_BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	Humboldt		Retired	Market
PG&E	7STDRD_1_SOLAR1	35065	7STNDRD_1	21	5.40	FW	Kern	South Kern PP, Kern Oil	Aug NQC	Solar
PG&E	ADOBEE_1_SOLAR	35021	Q622B	34.5	5.40	1	Kern	South Kern PP	Aug NQC	Solar

PG&E	BDGRCK_1_UNITS	35029	BADGERCK	13.8	40.20	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	BEARMT_1_UNIT	35066	PSE-BEAR	13.8	44.00	1	Kern	South Kern PP, Westpark	Aug NQC	Net Seller
PG&E	BKRFLD_2_SOLAR1				0.37		Kern	South Kern PP	Not modeled Aug NQC	Solar
PG&E	DEXZEL_1_UNIT	35024	DEXEL +	13.8	17.78	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	DISCOV_1_CHEVRN	35062	DISCOVRY	13.8	2.58	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	DOUBLC_1_UNITS	35023	DOUBLE C	13.8	49.50	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KERNFT_1_UNITS	35026	KERNFRNT	9.11	48.60	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	LAMONT_1_SOLAR1	35019	REGULUS	0.4	16.20	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR2	35092	Q744G4	0.38	5.40	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR3	35087	Q744G3	0.4	4.05	3	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR4	35059	Q744G2	0.4	21.38	2	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR5	35054	Q744G1	0.4	4.50	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.1	42.50	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	MAGUND_1_BKISR1				0.27		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Solar
PG&E	MAGUND_1_BKSSR2				1.42		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Solar
PG&E	MTNPOS_1_UNIT	35036	MT POSO	13.8	34.35	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	OLDRIV_6_BIOGAS				1.69		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRIV_6_CESDBM				0.90		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRIV_6_LKVBM1				0.91		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRV1_6_SOLAR	35091	OLD_RVR1	12.5	5.40	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar
PG&E	SIERRA_1_UNITS	35027	HISIERRA	9.11	49.57	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR1	35089	S_KERN	0.48	5.40	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar

PG&E	SKERN_6_SOLAR2	365563	Q885	0.36	2.70	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar
PG&E	VEDDER_1_SEKERN	35046	SEKR	9.11	2.19	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	ZZZZZ_KRNCNY_6_UNIT	35018	KERNCNYN	11	0.00	1	Kern	South Kern PP, Kern 70 kV	Retired	Market
PG&E	ZZZZZ_OILDAL_1_UNIT 1	35028	OILDALE	9.11	0.00	RT	Kern	South Kern PP, Kern Oil	Retired	Net Seller
PG&E	ZZZZZ_RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.1	0.00	1	Kern	South Kern PP, Kern 70 kV	Retired	Market
PG&E	ZZZZZ_ULTOGL_1_POSO	35035	ULTR PWR	9.11	0.00	1	Kern	South Kern PP, Kern Oil	Retired	QF/Selfgen
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	NCNB	Eagle Rock, Fulton		Market
PG&E	CLOVDL_1_SOLAR				0.41		NCNB	Eagle Rock, Fulton	Not modeled Aug NQC	Solar
PG&E	CSTOGA_6_LNDFIL				0.00		NCNB	Fulton	Not modeled Energy Only	Market
PG&E	FULTON_1_QF				0.06		NCNB	Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	GEYS11_7_UNIT11	31412	GEYSER11	13.8	68.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	NCNB	Fulton		Market
PG&E	GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	NCNB			Market
PG&E	GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	NCNB	Fulton		Market
PG&E	GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	NCNB	Fulton		Market
PG&E	GEYS17_2_BOTRCK				8.23	1	NCNB	Fulton		Market
PG&E	GEYS17_7_UNIT17	31422	GEYSER17	13.8	56.00	1	NCNB	Fulton		Market
PG&E	GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	NCNB			Market
PG&E	GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	NCNB			Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	2	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	NCNB	Eagle Rock, Fulton		Market
PG&E	GYSRVL_7_WSPRNG				1.48		NCNB	Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	HILAND_7_YOLOWD				0.00		NCNB	Eagle Rock, Fulton	Not Modeled. Energy Only	Market
PG&E	IGNACO_1_QF				0.01		NCNB		Not modeled Aug NQC	QF/Selfgen

PG&E	INDVLY_1_UNITS	31436	INDIAN V	9.1	0.79	1	NCNB	Eagle Rock, Fulton	Aug NQC	Net Seller
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.11	1	NCNB	Fulton	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.11	2	NCNB	Fulton	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	0.93	3	NCNB	Fulton	Aug NQC	Market
PG&E	NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	NCNB		Aug NQC	MUNI
PG&E	NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	NCNB		Aug NQC	MUNI
PG&E	NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	NCNB	Fulton	Aug NQC	MUNI
PG&E	NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	NCNB	Fulton	Aug NQC	MUNI
PG&E	NOVATO_6_LNDFL				3.56		NCNB		Not modeled Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	1.32	1	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.60	3	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.60	4	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_7_VECINO				0.01		NCNB	Eagle Rock, Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	1	NCNB			Market
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	2	NCNB			Market
PG&E	SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	47.00	1	NCNB			Market
PG&E	SNMALF_6_UNITS	31446	SONMA LF	9.1	3.12	1	NCNB	Fulton	Aug NQC	QF/Selfgen
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	1.21	2	NCNB	Eagle Rock, Fulton	Aug NQC	MUNI
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	0.49	1	NCNB	Eagle Rock, Fulton	Aug NQC	MUNI
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	2	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_WDFRDF_2_UNITS	31404	WEST FOR	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_WDFRDF_2_UNITS	31404	WEST FOR	13.8	0.00	2	NCNB	Fulton	Retired	Market
PG&E	ZZZZZZ_GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ALLGNY_6_HYDRO1				0.03		Sierra		Not modeled Aug NQC	Market
PG&E	APLHIL_1_SLABCK				0.00	1	Sierra	South of Rio Oso, South of Palermo	Not modeled Energy Only	Market
PG&E	BANGOR_6_HYDRO				1.00		Sierra		Not modeled Aug NQC	Market
PG&E	BELDEN_7_UNIT 1	31784	BELDEN	13.8	119.00	1	Sierra	South of Palermo	Aug NQC	Market

PG&E	BIOMAS_1_UNIT 1	32156	WOODLAND	9.11	24.31	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Net Seller
PG&E	BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.68		Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	BOGUE_1_UNITA1	32451	FREC	13.8	47.60	1	Sierra	Bogue, Drum-Rio Oso	Aug NQC	Market
PG&E	BOWMN_6_HYDRO	32480	BOWMAN	9.11	2.54	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	BUCKCK_2_HYDRO				0.04		Sierra	South of Palermo	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_OAKFLT				1.30		Sierra	South of Palermo	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	30.63	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	26.62	2	Sierra	South of Palermo	Aug NQC	Market
PG&E	CAMPFW_7_FARWST	32470	CMP.FARW	9.11	2.90	1	Sierra		Aug NQC	MUNI
PG&E	CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	42.00	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	Sierra		Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	Sierra		Aug NQC	MUNI
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	35.54	2	Sierra	South of Palermo	Aug NQC	Market
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	34.86	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	DAVIS_1_SOLAR1				0.00		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Solar
PG&E	DAVIS_1_SOLAR2				0.00		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Solar
PG&E	DAVIS_7_MNMETH				1.76		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	DEADCK_1_UNIT	31862	DEADWOOD	9.11	0.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	DEERCR_6_UNIT 1	32474	DEER CRK	9.11	2.98	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market

PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	15.64	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.26	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_UNIT 5	32454	DRUM 5	13.8	50.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo		Market
PG&E	ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo		Market
PG&E	FMEADO_6_HELLHL	32486	HELLHOLE	9.11	0.43	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.00	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	GRIDLY_6_SOLAR	38054	GRIDLEY	60	0.00	1	Sierra	Pease	Energy Only	Solar
PG&E	GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	38.99	1	Sierra	Pease, Drum-Rio Oso	Aug NQC	QF/Selfgen
PG&E	HALSEY_6_UNIT	32478	HALSEY F	9.11	13.50	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.05	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	QF/Selfgen
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.04	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	QF/Selfgen
PG&E	HIGGNS_1_COMBIE				0.22		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market

PG&E	HIGGNS_7_QFUNTS				0.24		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	QF/Selfgen
PG&E	KELYRG_6_UNIT	31834	KELLYRDG	9.11	11.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	LIVEOK_6_SOLAR				0.14		Sierra	Pease	Not modeled Aug NQC	Solar
PG&E	LODIEC_2_PL1X2	38123	LODI CT1	18	199.03	1	Sierra	South of Rio Oso, South of Palermo		MUNI
PG&E	LODIEC_2_PL1X2	38124	LODI ST1	18	103.55	1	Sierra	South of Rio Oso, South of Palermo		MUNI
PG&E	MDFKRL_2_PROJCT	32458	RALSTON	13.8	82.13	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.94	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.94	2	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	NAROW1_2_UNIT	32466	NARROWS1	9.1	12.00	1	Sierra		Aug NQC	Market
PG&E	NAROW2_2_UNIT	32468	NARROWS2	9.1	28.51	1	Sierra		Aug NQC	MUNI
PG&E	NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.51	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	OROVIL_6_UNIT	31888	OROVLLE	9.11	7.50	1	Sierra	Drum-Rio Oso	Aug NQC	Market
PG&E	OXBOW_6_DRUM	32484	OXBOW F	9.11	3.62	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	PLACVL_1_CHILIB	32510	CHILIBAR	4.2	8.40	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	PLACVL_1_RCKCRE				1.20		Sierra	South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	PLSNTG_7_LNCLND	32408	PLSNT GR	60	3.09		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	57.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.90	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RIOOSO_1_QF				1.15		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	QF/Selfgen

PG&E	ROLLIN_6_UNIT	32476	ROLLINSF	9.11	13.50	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	SLYCRK_1_UNIT 1	31832	SLY.CR.	9.11	13.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	SPAULD_6_UNIT 3	32472	SPAULDG	9.11	1.59	3	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	7.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.40	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.93	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	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		MUNI
PG&E	ULTRCK_2_UNIT	32500	ULTR RCK	9.11	22.83	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	60.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	WHEATL_6_LNDFIL	32350	WHEATLND	60	3.55		Sierra		Not modeled Aug NQC	Market
PG&E	WISE_1_UNIT 1	32512	WISE	12	14.50	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	WISE_1_UNIT 2	32512	WISE	12	3.20	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	YUBACT_1_SUNSWT	32494	YUBA CTY	9.11	49.97	1	Sierra	Pease, Drum-Rio Oso	Aug NQC	Net Seller
PG&E	YUBACT_6_UNITA1	32496	YCEC	13.8	47.60	1	Sierra	Pease, Drum-Rio Oso		Market
PG&E	ZZ_NA	32162	RIV.DLTA	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Palermo	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	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	365936	Q653FSPV	0.48	2.46	1	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Solar

PG&E	ZZZ_New Unit	365940	Q653FSPV	0.48	2.46	2	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365938	Q653FC6B	0.48	0.00	2	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Battery
PG&E	ZZZZZ_GOLDHL_1_QF				0.00		Sierra	South of Rio Oso, South of Palermo	Retired	QF/Selfgen
PG&E	ZZZZZ_GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	0.00	1	Sierra	Bogue, Drum-Rio Oso	Retired	Market
PG&E	ZZZZZ_GRNLF1_1_UNITS	32491	GRNLEAF1	13.8	0.00	2	Sierra	Bogue, Drum-Rio Oso	Retired	Market
PG&E	ZZZZZ_KANAKA_1_UNIT				0.00		Sierra	Drum-Rio Oso	Retired	MUNI
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	1	Sierra	Drum-Rio Oso	Retired	QF/Selfgen
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	2	Sierra	Drum-Rio Oso	Retired	QF/Selfgen
PG&E	BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.92	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.92	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.92	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CRWCKS_1_SOLAR1	34051	Q539	34.5	0.00	1	Stockton	Tesla-Bellota	Energy Only	Solar
PG&E	DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	FROGTN_1_UTICAA				1.40		Stockton	Tesla-Bellota, Stanislaus	Not Modeled Aug NQC	Market
PG&E	FROGTN_1_UTICAM				2.37		Stockton	Tesla-Bellota, Stanislaus	Not Modeled Aug NQC	Market
PG&E	LOCKFD_1_BEARCK				0.41		Stockton	Tesla-Bellota	Not Modeled Aug NQC	Solar
PG&E	LOCKFD_1_KSOLAR				0.27		Stockton	Tesla-Bellota	Not Modeled Aug NQC	Solar
PG&E	LODI25_2_UNIT 1	38120	LODI25CT	9.11	23.80	1	Stockton	Lockeford		MUNI
PG&E	MANTEC_1_ML1SR1				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Solar
PG&E	PEORIA_1_SOLAR				0.41		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Solar
PG&E	PHOENX_1_UNIT				0.84		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	138.11	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	85.70	1	Stockton	Tesla-Bellota		Market

PG&E	SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	85.70	1	Stockton	Tesla-Bellota		Market
PG&E	SMPRIP_1_SMPSON	33810	SP CMPNY	13.8	46.05	1	Stockton	Tesla-Bellota	Aug NQC	Market
PG&E	SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	12.88	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	SPIFBD_1_PL1X2	34055	SPISONORA	13.8	5.67	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.01	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	18.26	1	Stockton	Tesla-Bellota	Aug NQC	Net Seller
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	7.41	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	6.58	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	4.86	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	Market
PG&E	VLYHOM_7_SSJID				0.65		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	MUNI
PG&E	ZZZ_New Unit	365684	Q1103		10.80	1	Stockton	Tesla-Bellota	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34053	Q539		0.00	1	Stockton	Tesla-Bellota	Energy Only	Solar
PG&E	ZZZ_New Unit	365556	SAFEWAYB		0.00	RN	Stockton	Tesla-Bellota	Energy Only	Market
PG&E	ZZZZZ_FROGTN_7_UTICA				0.00		Stockton	Tesla-Bellota, Stanislaus	Retired	Market
PG&E	ZZZZZ_STOKCG_1_UNIT 1	33814	INGREDION	12.5	0.00	RN	Stockton	Tesla-Bellota	Retired	QF/Selfgen
PG&E	ZZZZZZ_NA	33830	GEN.MILL	9.11	0.00	1	Stockton	Lockeford	Retired	QF/Selfgen
PG&E	ZZZZZZZ_SANJOA_1_UNIT 1	33808	SJ COGEN	13.8	0.00	1	Stockton	Tesla-Bellota	Retired	QF/Selfgen
PG&E	ZZZZZZZ_THMENG_1_UNIT 1	33806	TH.E.DV.	13.8	0.00	1	Stockton	Tesla-Bellota	Retired	Net Seller
SCE	ACACIA_6_SOLAR	29878	ACACIA_G	0.48	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	ALAMO_6_UNIT	25653	ALAMO SC	13.8	11.36	1	BC/Ventura		Aug NQC	MUNI
SCE	BGSKYN_2_AS2SR1	29774	ANTLOP2_G1	0.42	28.35	EQ	BC/Ventura		Aug NQC	Solar
SCE	BGSKYN_2_ASPSR2				27.00		BC/Ventura		Aug NQC	Solar
SCE	BGSKYN_2_BS3SR3				5.40		BC/Ventura		Aug NQC	Solar
SCE	BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	92.02	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	92.02	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	51.18	2	BC/Ventura	Rector, Vestal	Aug NQC	Market

SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.99	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.80	42	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.60	41	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	43.30	82	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	35.92	5	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	35.43	4	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.44	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.44	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	33.46	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.71	4	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	24.01	81	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.26	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.26	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.58	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.39	4	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.40	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.21	6	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.73	5	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.45	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_7_DAM7				0.00		BC/Ventura	Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGCRK_7_MAMRES				0.00		BC/Ventura	Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGSKY_2_BSKSR6	29734	BSKY G BC	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_BSKSR7	29737	BSKY G WABS	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_BSKSR8	29740	BSKY G ABSR	0.38	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR1	29704	BSKY G SMR	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR2	29744	BSKY_G_ESC	0.42	34.41	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR3	29725	BSKY_G_BD	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR4	29701	BSKY_G_BA	0.42	17.26	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR5	29731	BSKY_G_BB	0.42	1.35	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR6	29728	BSKY_G_SOLV	0.42	22.95	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR7	29731	BSKY_G_ADSR	0.42	13.50	1	BC/Ventura		Aug NQC	Solar
SCE	CEDUCR_2_SOLAR1	25049	DUCOR1	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR2	25052	DUCOR2	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR3	25055	DUCOR3	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR4	25058	DUCOR4	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	DELSUR_6_BSOLAR	24411	DELSUR_DIST	66	0.81	1	BC/Ventura		Aug NQC	Solar

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

SCE	DELSUR_6_CREST	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	DELSUR_6_DRYFRB	24411	DELSUR_DIST	66	1.35	1	BC/Ventura		Aug NQC	Market
SCE	DELSUR_6_SOLAR1	24411	DELSUR_DIST	66	1.76	2	BC/Ventura		Aug NQC	Solar
SCE	DELSUR_6_SOLAR4	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Solar
SCE	DELSUR_6_SOLAR5	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Solar
SCE	EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	BC/Ventura	Rector, Vestal		Market
SCE	EDMONS_2_NSPIN	25605	EDMON1AP	14.4	16.86	1	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25606	EDMON2AP	14.4	16.86	2	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	3	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	4	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	5	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	6	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	7	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	8	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	9	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	10	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	11	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	12	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	13	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	14	BC/Ventura		Pumps	MUNI
SCE	GLDFGR_6_SOLAR1	25079	PRIDE B G	0.64	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	GLDFGR_6_SOLAR2	25169	PRIDE C G	0.64	3.08	1	BC/Ventura		Aug NQC	Solar
SCE	GLOW_6_SOLAR	29896	APPINV	0.42	0.00	EQ	BC/Ventura		Energy Only	Solar
SCE	GOLETA_2_QF	25335	GOLETA_DIST	66	0.04	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	QF/Selfgen
SCE	GOLETA_6_ELLWOD	29004	ELLWOOD	13.8	54.00	1	BC/Ventura	S.Clara, Moorpark, Goleta		Market
SCE	GOLETA_6_EXGEN	24362	EXGEN2	13.8	0.00	G1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC - Currently out of service	QF/Selfgen
SCE	GOLETA_6_EXGEN	24326	EXGEN1	13.8	0.00	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC - Currently out of service	QF/Selfgen
SCE	GOLETA_6_GAVOTA	25335	GOLETA_DIST	66	0.00	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	Market

SCE	GOLETA_6_TAJIGS	25335	GOLETA_DIST	66	2.84	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	Market
SCE	LEBECS_2_UNITS	29053	PSTRIAS1	18	173.86	S1	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29051	PSTRIAG1	18	168.90	G1	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29052	PSTRIAG2	18	168.90	G2	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29054	PSTRIAG3	18	168.90	G3	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29055	PSTRIAS2	18	84.45	S2	BC/Ventura		Aug NQC	Market
SCE	LITLRK_6_GBCSR1	24419	LTLRCK_DIST	66	0.81	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SEPV01	24419	LTLRCK_DIST	66	0.00	AS	BC/Ventura		Energy Only	Market
SCE	LITLRK_6_SOLAR1	24419	LTLRCK_DIST	66	1.35	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR2	24419	LTLRCK_DIST	66	0.54	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR3	24419	LTLRCK_DIST	66	0.54	AS	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR4	24419	LTLRCK_DIST	66	0.81	AS	BC/Ventura		Aug NQC	Solar
SCE	LNCSTR_6_CREST				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	BC/Ventura	S.Clara, Moorpark		Market
SCE	MOORPK_2_CALABS	25081	WDT251	13.8	4.57	EQ	BC/Ventura	Moorpark	Aug NQC	Market
SCE	MOORPK_6_QF				0.80		BC/Ventura	Moorpark	Not modeled Aug NQC	Market
SCE	NEENCH_6_SOLAR	29900	ALPINE_G	0.48	17.82	EQ	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_CREST				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	OASIS_6_GBDSR4	24421	OASIS_DIST	66	0.81	1	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_SOLAR1	25095	SOLARISG2	0.2	0.00	EQ	BC/Ventura		Energy Only	Solar
SCE	OASIS_6_SOLAR2	25075	SOLARISG	0.2	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_SOLAR3				0.00		BC/Ventura		Not modeled Energy Only	Solar
SCE	OMAR_2_UNIT 1	24102	OMAR 1G	13.8	70.30	1	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 2	24103	OMAR 2G	13.8	71.24	2	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 3	24104	OMAR 3G	13.8	74.03	3	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 4	24105	OMAR 4G	13.8	81.44	4	BC/Ventura			Net Seller
SCE	ORMOND_7_UNIT 1	24107	ORMOND1G	26	0.00	1	BC/Ventura	Moorpark	Retired by 2025	Market
SCE	ORMOND_7_UNIT 2	24108	ORMOND2G	26	0.00	2	BC/Ventura	Moorpark	Retired by 2025	Market
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	1	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	2	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	3	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	4	BC/Ventura		Pumps	MUNI

SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	5	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	6	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	7	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	8	BC/Ventura		Pumps	MUNI
SCE	PLAINV_6_BSOLAR	29917	SSOLAR)GRW KS	0.8	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PLAINV_6_DSOLAR	29914	WADR_PV	0.42	2.70	1	BC/Ventura		Aug NQC	Solar
SCE	PLAINV_6_NLRSR1	29921	NLR_INVTR	0.42	0.00	1	BC/Ventura		Aug NQC	Solar
SCE	PLAINV_6_SOLAR3	25089	CNTRL ANT G	0.42	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PLAINV_6_SOLARC	25086	SIRA SOLAR G	0.8	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PMDLET_6_SOLAR1				2.70		BC/Ventura		Not modeled Aug NQC	Solar
SCE	RECTOR_2_CREST	25333	RECTOR_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_KAWEAH	25333	RECTOR_DIST	66	1.74	S2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_KAWH 1	24370	KAWGEN	13.8	0.52	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_QF	25333	RECTOR_DIST	66	3.94	S1	BC/Ventura	Rector, Vestal	Aug NQC	QF/Selfgen
SCE	RECTOR_2_TFDBM1				0.00		BC/Ventura	Rector, Vestal	Energy Only	Market
SCE	RECTOR_7_TULARE	25333	RECTOR_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	REDMAN_2_SOLAR	24425	REDMAN_DIST	66	1.01	AS	BC/Ventura		Aug NQC	Solar
SCE	REDMAN_6_AVSSR1				0.81		BC/Ventura		Aug NQC	Solar
SCE	ROSMND_6_SOLAR	24434	ROSAMOND_D IS	66	0.81	AS	BC/Ventura		Aug NQC	Solar
SCE	RSMSLR_6_SOLAR1	29984	DAWNGEN	0.8	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	RSMSLR_6_SOLAR2	29888	TWILGHTG	0.8	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	SAUGUS_6_CREST				0.00		BC/Ventura		Energy Only	Market
SCE	SAUGUS_6_MWDFTH	25336	SAUGUS_MWD	66	5.40	S1	BC/Ventura		Aug NQC	MUNI
SCE	SAUGUS_6_QF	24135	SAUGUS	66	0.70		BC/Ventura		Not modeled Aug NQC	QF/Selfgen
SCE	SAUGUS_7_CHIQCN	24135	SAUGUS	66	5.63		BC/Ventura		Not modeled Aug NQC	Market
SCE	SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.34		BC/Ventura		Not modeled Aug NQC	QF/Selfgen
SCE	SHUTLE_6_CREST	24426	SHUTTLE_DIS T	66	0.00	AS	BC/Ventura		Energy Only	Market
SCE	SNCLRA_2_HOWLNG	25080	SANTACLR_DI S	13.8	8.72	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_SPRHYD	25080	SANTACLR_DI S	13.8	0.18	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_UNIT	29952	CAMGEN	13.8	27.50	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_UNIT1	24159	WILLAMET	3.8	15.63	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market

SCE	SNCLRA_6_OXGEN	24110	OXGEN	13.8	35.38	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_PROCGN	24119	PROCGEN	13.8	45.47	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_QF	25080	SANTACLR_DIS	13.8	0.00	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SPRGVL_2_CREST	25334	SPRNGVL_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Energy Only	Market
SCE	SPRGVL_2_QF	25334	SPRNGVL_DIST	66	0.18	S1	BC/Ventura	Rector, Vestal	Aug NQC	QF/Selfgen
SCE	SPRGVL_2_TULE	25334	SPRNGVL_DIST	66	0.00	S2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	SPRGVL_2_TULESC	25334	SPRNGVL_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	1	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	2	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	3	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	4	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.17	5	BC/Ventura		Aug NQC	Market
SCE	SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	77.41	1	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 2	24144	SYCCYN2G	13.8	80.00	2	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 3	24145	SYCCYN3G	13.8	80.00	3	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 4	24146	SYCCYN4G	13.8	80.00	4	BC/Ventura		Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.80	D1	BC/Ventura		Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.80	D2	BC/Ventura		Aug NQC	Net Seller
SCE	VESTAL_2_KERN	24372	KR 3-1	11	6.50	1	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_KERN	24373	KR 3-2	11	6.13	2	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_RTS042				0.00		BC/Ventura	Vestal	Not modeled Energy Only	Market
SCE	VESTAL_2_SOLAR1	25064	TULRESLR_1	0.39	5.40	1	BC/Ventura	Vestal	Aug NQC	Solar
SCE	VESTAL_2_SOLAR2	25065	TULRESLR_2	0.39	3.78	1	BC/Ventura	Vestal	Aug NQC	Solar
SCE	VESTAL_2_UNIT1				4.03		BC/Ventura	Vestal	Not modeled Aug NQC	Market
SCE	VESTAL_2_WELLHD	24116	WELLGEN	13.8	49.00	1	BC/Ventura	Vestal		Market
SCE	VESTAL_6_QF	29008	LAKEGEN	13.8	5.49	1	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	WARNE_2_UNIT	25651	WARNE1	13.8	20.79	1	BC/Ventura		Aug NQC	MUNI
SCE	WARNE_2_UNIT	25652	WARNE2	13.8	20.79	2	BC/Ventura		Aug NQC	MUNI
SCE	ZZ_NA	24340	CHARMIN	13.8	2.80	1	BC/Ventura	S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
SCE	ZZZ_New Unit	698508	WDT1519	66	100.00	EQ	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery

SCE	ZZZ_New Unit	699101	WDT1454	66	40.00	EQ	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	99739	GOLETA-DIST	66	30.00	EQ	BC/Ventura	S.Clara, Moorpark, Goleta	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	99740	S.CLARA-DIST	66	11.00	EQ	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	24127	S.CLARA	66	9.27	X8	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	24057	GOLETA	66	4.73	X8	BC/Ventura	S.Clara, Moorpark, Goleta	No NQC - Pmax	Battery
SCE	ZZZZZ_APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	BC/Ventura		Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	BC/Ventura		Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	BC/Ventura		Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	0.00	1	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	0.00	2	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 3	24222	MANDLY3G	16	0.00	3	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MOORPK_7_UNITA1	24098	MOORPARK	66	0.00		BC/Ventura	Moorpark	Retired	Market
SCE	ZZZZZ_PANDOL_6_UNIT	24113	PANDOL	13.8	0.00	1	BC/Ventura	Vestal	Retired	Market
SCE	ZZZZZ_PANDOL_6_UNIT	24113	PANDOL	13.8	0.00	2	BC/Ventura	Vestal	Retired	Market
SCE	ZZZZZ_SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		BC/Ventura		Retired	Market
SCE	ZZZZZ_SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	0.00	D1	BC/Ventura		Retired	MUNI
SCE	ZZZZZ_VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	0.00	1	BC/Ventura	Vestal	Retired	QF/Selfgen
SCE	ALAMIT_2_PL1X3	24577	ALMT STG	18	251.66	S1	LA Basin	Western		Market
SCE	ALAMIT_2_PL1X3	24575	ALMT CTG1	18	211.52	G1	LA Basin	Western		Market
SCE	ALAMIT_2_PL1X3	24576	ALMT CTG2	18	211.52	G2	LA Basin	Western		Market
SCE	ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	0.00	3	LA Basin	Western	Retired by 2025	Market
SCE	ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	0.00	4	LA Basin	Western	Retired by 2025	Market

SCE	ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	0.00	5	LA Basin	Western	Retired by 2025	Market
SCE	ALTWD_1_QF	25635	ALTWIND	115	3.82	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ALTWD_1_QF	25635	ALTWIND	115	3.82	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	51.98	1	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24012	ARCO 2G	13.8	51.98	2	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24013	ARCO 3G	13.8	51.98	3	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24014	ARCO 4G	13.8	51.98	4	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24163	ARCO 5G	13.8	25.99	5	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24164	ARCO 6G	13.8	25.99	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	10.29	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	BUCKWD_1_NPALM1	25634	BUCKWIND	115	0.65		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	BUCKWD_1_QF	25634	BUCKWIND	115	3.47	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.28	W5	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CABZON_1_WINDA1	29290	CABAZON	33	8.61	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CAPWD_1_QF	25633	CAPWIND	115	4.11	QF	LA Basin	Eastern, Valley-Devers	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	Solar
SCE	CENTER_2_TECNG1				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	CENTER_6_PEAKER	29308	CTRPKGEN	13.8	47.11	1	LA Basin	Western		Market
SCE	CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	3.77	1	LA Basin	Western, El Nido	Aug NQC	Net Seller

SCE	CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	3.77	2	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHINO_2_APEBT1	25180	WDT1250BESS_	0.48	20.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	CHINO_2_JURUPA				0.00		LA Basin	Eastern	Not modeled Energy Only	Market
SCE	CHINO_2_QF				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	CHINO_2_SASOLR				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CHINO_2_SOLAR				0.27		LA Basin	Eastern	Not modeled	Solar
SCE	CHINO_2_SOLAR2				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CHINO_6_CIMGEN	24026	CIMGEN	13.8	26.00	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	CHINO_7_MILIKN	24024	CHINO	66	1.19		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	CORONS_2_SOLAR				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CORONS_6_CLRWTR	29338	CLRWTRCT	13.8	20.72	G1	LA Basin	Eastern		MUNI
SCE	CORONS_6_CLRWTR	29340	CLRWTRST	13.8	7.28	S1	LA Basin	Eastern		MUNI
SCE	DELAMO_2_SOLAR1				0.41		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR2				0.47		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR3				0.34		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR4				0.35		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR5				0.27		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR6				0.54		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLRC1				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	DELAMO_2_SOLRD				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	DEVERS_1_QF	25639	SEAWIND	115	0.92	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_QF	25632	TERAWND	115	0.76	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	Solar
SCE	DEVERS_1_SOLAR1				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_1_SOLAR2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_2_CS2SR4				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_2_DHSPG2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DMDVLY_1_UNITS	25425	ESRP P2	6.9	3.00	8	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	36.95	3	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	36.95	4	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	27.72	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	27.72	2	LA Basin	Eastern	Aug NQC	MUNI
SCE	ELLIS_2_QF	24325	ORCOGEN	13.8	0.06	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	Not modeled Energy Only	Market
SCE	ETIWND_2_FONTNA	24055	ETIWANDA	66	0.21		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_2_RTS010	24055	ETIWANDA	66	0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS015	24055	ETIWANDA	66	0.81		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS017	24055	ETIWANDA	66	0.95		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS018	24055	ETIWANDA	66	0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS023	24055	ETIWANDA	66	0.68		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS026	24055	ETIWANDA	66	1.62		LA Basin	Eastern	Not modeled Aug NQC	Market

SCE	ETIWND_2_RTS027	24055	ETIWANDA	66	0.54		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_SOLAR1				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_SOLAR2				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_SOLAR5				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_UNIT1	24071	INLAND	13.8	10.34	1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	47.39	1	LA Basin	Eastern		Market
SCE	ETIWND_6_MWDETI	25422	ETI MWDG	13.8	16.70	1	LA Basin	Eastern	Aug NQC	Market
SCE	GARNET_1_SOLAR	24815	GARNET	115	0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	GARNET_1_SOLAR2	24815	GARNET	115	1.08		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Solar
SCE	GARNET_1_UNITS	24815	GARNET	115	1.63	G1	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	1.28	G3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.56	G2	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_WIND	24815	GARNET	115	1.37		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_1_WINDS	24815	GARNET	115	4.73	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_DIFWD1	24815	GARNET	115	1.65		LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_HYDRO	24815	GARNET	115	0.76	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_WIND1	24815	GARNET	115	2.35		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND2	24815	GARNET	115	2.46		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND3	24815	GARNET	115	2.65		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND4	24815	GARNET	115	2.06		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind

SCE	GARNET_2_WIND5	24815	GARNET	115	0.63		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WPMWD6	24815	GARNET	115	1.25		LA Basin	Eastern, Valley-Devers	Not modeled 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		Market
SCE	HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	LA Basin	Western		Market
SCE	HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	LA Basin	Western		Market
SCE	HINSON_6_CARBGN	24020	CARBGEN1	13.8	14.43	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.43	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	34.00	D1	LA Basin	Western	Aug NQC	Market
SCE	HNTGBH_2_PL1X3	24581	HUNTBCH CTG2	18	211,23	G2	LA Basin	Western		Market
SCE	HNTGBH_2_PL1X3	24582	HUNTBCH STG	18	251.34	S1	LA Basin	Western		Market
SCE	HNTGBH_2_PL1X3	24580	HUNTBCH CTG1	18	211.23	G1	LA Basin	Western		Market
SCE	HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	0.00	2	LA Basin	Western	Retired by 2025	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	LACIEN_2_VENICE	24337	VENICE	13.8	3.00	1	LA Basin	Western, El Nido	Aug NQC	MUNI
SCE	LAGBEL_6_QF	29951	REFUSE	13.8	0.35	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				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_LNDFL				0.81		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_MLBBTA	25185	WDT1425_G1	0.48	10.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	MIRLOM_2_MLBBTB	25186	WDT1426_G2	0.48	10.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	MIRLOM_2_ONTARO				1.49		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS032				0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS033				0.27		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_TEMESC				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	LA Basin	Eastern		Market
SCE	MIRLOM_7_MWDLKM	24210	MIRALOMA	66	1.80		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	3.20	1	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	3.20	2	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	3.20	3	LA Basin	Eastern	Aug NQC	Market
SCE	MTWIND_1_UNIT 1	29060	MOUNTWND	115	9.32	S1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 2	29060	MOUNTWND	115	4.66	S2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 3	29060	MOUNTWND	115	4.71	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	7.16	S1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C2	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C3	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.00	C4	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_QF	24211	OLINDA	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	OLINDA_7_BLKSND	24211	OLINDA	66	0.36		LA Basin	Western	Not modeled Aug NQC	Market
SCE	OLINDA_7_LNDFIL	24211	OLINDA	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen

SCE	PADUA_2_ONTARO	24111	PADUA	66	0.35		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_SOLAR1	24111	PADUA	66	0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	PADUA_6_MWDSDM	24111	PADUA	66	2.60		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	PADUA_6_QF	24111	PADUA	66	0.39		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_7_SDIMAS	24111	PADUA	66	1.05		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	PANSEA_1_PANARO	25640	PANAERO	115	6.30	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	PWEST_1_UNIT	24815	GARNET	115	0.44	PC	LA Basin	Western	Aug NQC	Market
SCE	REDOND_7_UNIT 5	24121	REDON5 G	18	0.00	5	LA Basin	Western	Retired by 2025	Market
SCE	REDOND_7_UNIT 6	24122	REDON6 G	18	0.00	6	LA Basin	Western	Retired by 2025	Market
SCE	REDOND_7_UNIT 8	24124	REDON8 G	20	0.00	8	LA Basin	Western	Retired by 2025	Market
SCE	RENWD_1_QF	25636	RENWIND	115	1.33	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RENWD_1_QF	25636	RENWIND	115	1.32	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RVSIDE_2_RERCU3	24299	RERC2G3	13.8	49.00	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_2_RERCU4	24300	RERC2G4	13.8	49.00	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_SOLAR1	24244	SPRINGEN	13.8	2.03		LA Basin	Eastern	Not modeled Aug NQC	Solar
SCE	RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	LA Basin	Eastern		Market
SCE	SANITR_6_UNITS	24324	SANIGEN	13.8	0.84	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	SANTGO_2_LNDFL1	24341	COYGEN	13.8	18.65	1	LA Basin	Western	Aug NQC	Market
SCE	SANTGO_2_MABBT1	25192	WDT1406_G	0.48	2.00	1	LA Basin	Western	Aug NQC	Battery
SCE	SANWD_1_QF	25646	SANWIND	115	3.26	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SANWD_1_QF	25646	SANWIND	115	3.26	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SBERDO_2_PSP3	24923	MNTV-ST1	18	257.82	1	LA Basin	Eastern, West of Devers		Market

SCE	SBERDO_2_PSP3	24921	MNTV-CT1	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP3	24922	MNTV-CT2	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24926	MNTV-ST2	18	257.82	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24924	MNTV-CT3	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24925	MNTV-CT4	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_QF	24214	SANBRDNO	66	0.14		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_2_REDLND	24214	SANBRDNO	66	0.54		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS005	24214	SANBRDNO	66	0.68		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS007	24214	SANBRDNO	66	0.68		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS011	24214	SANBRDNO	66	0.95		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS013	24214	SANBRDNO	66	0.95		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS016	24214	SANBRDNO	66	0.41		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS048	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers	Not modeled Energy Only	Market
SCE	SBERDO_2_SNTANA	24214	SANBRDNO	66	0.30		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_6_MILLCK	24214	SANBRDNO	66	1.09		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SENTNL_2_CTG1	29101	SENTINEL_G1	13.8	103.76	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG2	29102	SENTINEL_G2	13.8	95.34	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG3	29103	SENTINEL_G3	13.8	96.85	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG4	29104	SENTINEL_G4	13.8	102.47	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG5	29105	SENTINEL_G5	13.8	103.81	1	LA Basin	Eastern, Valley-Devers		Market

SCE	SENTNL_2_CTG6	29106	SENTINEL_G6	13.8	100.99	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG7	29107	SENTINEL_G7	13.8	97.06	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG8	29108	SENTINEL_G8	13.8	101.80	1	LA Basin	Eastern, Valley-Devers		Market
SCE	TIFFNY_1_DILLON	29021	WINTEC6	115	9.45	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TRNSWD_1_QF	25637	TRANWIND	115	8.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TULEWD_1_TULWD1				26.80		LA Basin	Eastern, Valley-Devers	Not modeled 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	3.80		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_RTS044	24160	VALLEYSC	115	2.16		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	Solar
SCE	VALLEY_5_SOLAR2	25082	WDT786	34.5	5.40	EQ	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Solar
SCE	VENWD_1_WIND1	25645	VENWIND	115	1.98	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND2	25645	VENWIND	115	3.37	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND3	25645	VENWIND	115	4.00	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	24241	MALBRG3G	13.8	49.26	S3	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	VILLPK_2_VALLYV	24216	VILLA PK	66	4.10	DG	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	VILLPK_6_MWDYOR	24216	VILLA PK	66	3.60		LA Basin	Western	Not modeled Aug NQC	MUNI
SCE	VISTA_2_RIALTO	24901	VSTA	230	0.27		LA Basin	Eastern	Not modeled	Market
SCE	VISTA_2_RTS028	24901	VSTA	230	0.95		LA Basin	Eastern	Not modeled Aug NQC	Market

SCE	VISTA_6_QF	24902	VSTA	66	0.10		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	WALCRK_2_CTG1	29201	WALCRKG1	13.8	96.43	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG2	29202	WALCRKG2	13.8	96.91	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG3	29203	WALCRKG3	13.8	96.65	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG4	29204	WALCRKG4	13.8	96.49	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG5	29205	WALCRKG5	13.8	96.65	1	LA Basin	Western		Market
SCE	WALNUT_2_SOLAR				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	WALNUT_6_HILLGEN	24063	HILLGEN	13.8	32.97	D1	LA Basin	Western	Aug NQC	Net Seller
SCE	WALNUT_7_WCOVST	24157	WALNUT	66	5.37		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WHTWTR_1_WINDA1	29061	WHITEWTR	33	12.92	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	ZZZ_New	698082	ALMITOS B1A	0.42	50.00	1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	698083	ALMITOS B12	0.42	50.00	1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	97624	WH_STN_1	13.8	49.00	1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	97625	WH_STN_2	13.8	49.00	1	LA Basin	Western	No NQC - Pmax	Market

SCE	ZZZZZ_ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	0.00	1	LA Basin	Western	Retired	Market
SCE	ZZZZZ_ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	0.00	2	LA Basin	Western	Retired	Market
SCE	ZZZZZ_ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	0.00	6	LA Basin	Western	Retired	Market
SCE	ZZZZZ_BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	0.00		LA Basin	Western	Retired	MUNI
SCE	ZZZZZ_CENTER_2_QF	29953	SIGGEN	13.8	0.00	D1	LA Basin	Western	Retired	QF/Selfgen
SCE	ZZZZZ_CHINO_6_SMPPAP	24140	SIMPSON	13.8	0.00	D1	LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_ETIWND_7_MIDVLY	24055	ETIWANDA	66	0.00		LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_ETIWND_7_UNIT 3	24052	MTNVIST3	18	0.00	3	LA Basin	Eastern	Retired	Market
SCE	ZZZZZ_ETIWND_7_UNIT 4	24053	MTNVIST4	18	0.00	4	LA Basin	Eastern	Retired	Market
SCE	ZZZZZ_HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	0.00	1	LA Basin	Western	Retired	Market
SCE	ZZZZZ_INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	0.00	1	LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	0.00	1	LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_LAGBEL_2_STG1				0.00		LA Basin	Western	Retired	Market
SCE	ZZZZZ_MIRLOM_6_DELGEN	29339	DELGEN	13.8	0.00	1	LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_REDOND_7_UNIT 7	24123	REDON7 G	20	0.00	7	LA Basin	Western	Retired	Market
SCE	ZZZZZ_RHONDO_2_QF	24213	RIOHONDO	66	0.00	DG	LA Basin	Western	Retired	QF/Selfgen
SCE	ZZZZZ_RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		LA Basin	Western	Retired	Net Seller
SCE	ZZZZZ_VALLEY_7_BADLND	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_VALLEY_7_UNITA1	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_WALNUT_7_WCOVCT	24157	WALNUT	66	0.00		LA Basin	Western	Retired	Market
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	51.25	1	SD-IV	San Diego, Border		Market

SDG&E	BREGGO_6_DEGRSL	22085	BORREGO	12.5	1.70	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	BREGGO_6_SOLAR	22082	BR GEN1	0.21	7.02	1	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CARLS1_2_CARCT1	22783	EA5 REPOWER1	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22784	EA5 REPOWER2	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22786	EA5 REPOWER4	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22788	EA5 REPOWER3	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS2_1_CARCT1	22787	EA5 REPOWER5	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CCRITA_7_RPPCHF	22124	CHCARITA	138	3.60	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CHILLS_1_SYCENG	22120	CARLTNHS	138	0.62	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	33.75	1	SD-IV		Aug NQC	Solar
SDG&E	CNTNLA_2_SOLAR2	23463	DW GEN3&4	0.33	0.00	2	SD-IV		Energy Only	Solar
SDG&E	CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.71	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	20.85	G1	SD-IV		Aug NQC	Solar
SDG&E	CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	16.68	G2	SD-IV		Aug NQC	Solar
SDG&E	CRELMN_6_RAMON1	22152	CREELMAN	69	0.54	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMON2	22152	CREELMAN	69	1.35	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMSR3				0.93		SD-IV	San Diego	Not modeled Aug NQC	Solar
SDG&E	CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	10.50	1	SD-IV	San Diego	Aug NQC	Wind
SDG&E	CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	17.55	G1	SD-IV		Aug NQC	Solar
SDG&E	CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	17.55	G2	SD-IV		Aug NQC	Solar
SDG&E	ELCAJN_6_EB1BT1	22208	EL CAJON	69	7.50	1	SD-IV	San Diego, El Cajon		Battery
SDG&E	ELCAJN_6_LM6K	23320	EC GEN2	13.8	48.10	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ELCAJN_6_UNITA1	22150	EC GEN1	13.8	45.42	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ENERSJ_2_WIND	23100	ECO GEN1 G1	0.69	32.57	G1	SD-IV		Aug NQC	Wind
SDG&E	ESCNDO_6_EB1BT1	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_EB2BT2	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_EB3BT3	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	1	SD-IV	San Diego		Market
SDG&E	ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.04	1	SD-IV	San Diego		Market
SDG&E	ESCO_6_GLMQF	22332	GOALLINE	69	36.41	1	SD-IV	San Diego	Aug NQC	Net Seller

SDG&E	IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	54.00	1	SD-IV		Aug NQC	Solar
SDG&E	IVWEST_2_SOLAR1	23155	DU GEN1 G1	0.2	21.91	G1	SD-IV		Aug NQC	Solar
SDG&E	IVWEST_2_SOLAR1	23156	DU GEN1 G2	0.2	18.59	G2	SD-IV		Aug NQC	Solar
SDG&E	JACMSR_1_JACSR1	23352	ECO GEN2	0.55	5.40	1	SD-IV		Aug NQC	Solar
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		Connect to CENACE/CFE grid for the summer – not available for ISO BAA RA purpose	Market
SDG&E	LAROA2_2_UNITA1	22997	INTBCT	16	176.81	1	SD-IV			Market
SDG&E	LAROA2_2_UNITA1	22996	INTBST	18	145.19	1	SD-IV			Market
SDG&E	LILIAC_6_SOLAR	22404	LILIAC	69	0.81	DG	SD-IV	San Diego		Solar
SDG&E	MRGT_6_MEF2	22487	MEF_MR2	13.8	44.00	1	SD-IV	San Diego		Market
SDG&E	MRGT_6_MMAREF	22486	MEF_MR1	13.8	45.00	1	SD-IV	San Diego		Market
SDG&E	MSHGTS_6_MMARLF	22448	MESAHGTS	69	4.03	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MSSION_2_QF	22496	MISSION	69	0.70	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MURRAY_6_UNIT	22532	MURRAY	69	0.00		SD-IV	San Diego	Not modeled Energy Only	Market
SDG&E	OCTILO_5_WIND	23314	OCO GEN G1	0.69	27.83	G1	SD-IV		Aug NQC	Wind
SDG&E	OCTILO_5_WIND	23318	OCO GEN G2	0.69	27.83	G2	SD-IV		Aug NQC	Wind
SDG&E	OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	SD-IV	San Diego		Market
SDG&E	OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	1	SD-IV	San Diego		Market
SDG&E	OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22607	OTAYMST1	16	272.27	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	22605	OTAYMGT1	18	165.16	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	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	PIOPIC_2_CTG1	23162	PIO PICO CT1	13.8	111.30	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG2	23163	PIO PICO CT2	13.8	112.70	1	SD-IV	San Diego	No NQC - Pmax	Market

SDG&E	PIOPIC_2_CTG3	23164	PIO PICO CT3	13.8	112.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PRCTVY_1_MIGBT1				0.00		SD-IV	San Diego	Aug NQC	Battery
SDG&E	SAMPSN_6_KELCO1	22704	SAMPSON	12.5	0.85	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	SLRMS3_2_SRMSR1	23442	DW GEN2 G3A	0.6	40.50	1	SD-IV		Aug NQC	Solar
SDG&E	SLRMS3_2_SRMSR1	23443	DW GEN2 G3B	0.6	27.00	1	SD-IV		Aug NQC	Solar
SDG&E	SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	TERMEX_2_PL1X3	22981	TDM STG	21	280.13	1	SD-IV			Market
SDG&E	TERMEX_2_PL1X3	22982	TDM CTG2	18	156.44	1	SD-IV			Market
SDG&E	TERMEX_2_PL1X3	22983	TDM CTG3	18	156.44	1	SD-IV			Market
SDG&E	VLCNTR_6_VCSLR	22870	VALCNTR	69	0.63	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR1	22870	VALCNTR	69	0.68	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR2	22870	VALCNTR	69	1.35	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VSTAES_6_VESBT1	23541	ME GEN 1_BS1	0.64	5.50	1	SD-IV	San Diego	No NQC - est. data	Battery
SDG&E	VSTAES_6_VESBT1	23216	ME GEN 1_BS2	0.48	5.50	1	SD-IV	San Diego	No NQC - est. data	Battery
SDG&E	WISTRA_2_WRSSR1	23287	Q429_G1	0.31	27.00	1	SD-IV		Aug NQC	Solar
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	23710	Q1170_BESS	0.48	62.50	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23441	DW GEN6	0.42	40.58	1	SD-IV		No NQC - est. data	Solar
SDG&E	ZZZ_New Unit	22020	AVOCADO	69	40.00	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23544	Q1169_BESS1	0.4	35.00	C8	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23519	Q1169_BESS2	0.4	35.00	C8	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23412	Q1434_G	0.64	30.00	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22942	BUE GEN 1_G1	0.69	11.60	G1	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22945	BUE GEN 1_G2	0.69	11.60	G2	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22947	BUE GEN 1_G3	0.69	11.60	G3	SD-IV		No NQC - est. data	Wind

SDG&E	ZZZ_New Unit	22256	ESCNDIDO	69	6.50	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22112	CAPSTRNO	138	5.90	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22112	CAPSTRNO	138	4.00	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23597	Q1175_BESS	0.48	0.00	1	SD-IV		Energy Only	Battery
SDG&E	ZZZ_New Unit	22404	LILAC	69	0.00	S2	SD-IV	San Diego	Energy Only	Battery
SDG&E	ZZZ_New Unit	22512	MONSRATE	69	0.00	S2	SD-IV	San Diego	Energy Only	Battery
SDG&E	ZZZZ_New Unit	23421	Q1531_BESS1	0.55	116.50	11	SD-IV		No NQC - Pmax	Battery
SDG&E	ZZZZ_New Unit	23425	Q1531_BESS2	0.55	116.50	11	SD-IV		No NQC - Pmax	Battery
SDG&E	ZZZZ_New Unit	23429	Q1531_BESS3	0.55	116.50	11	SD-IV		No NQC - Pmax	Battery
SDG&E	ZZZZ_New Unit	23398	Q1166_G	0.41	55.68	1	SD-IV		No NQC - 87%Pmax	Battery
SDG&E	ZZZZ_New Unit	22484	MIRAMAR1	69	30.00	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZZ_New Unit	23231	Q1432_G	0.39	8.10	1	SD-IV	San Diego	No NQC - est. data	Solar
SDG&E	ZZZZ_New Unit	22970	Q1532_GEN	0.6	5.40	1	SD-IV	San Diego	No NQC - est. data	Solar
SDG&E	ZZZZ_New Unit	23585	Q838_G1	0.6	4.32	1	SD-IV		No NQC - est. data	Solar
SDG&E	ZZZZ_New Unit	23586	Q838_G2	0.6	4.32	1	SD-IV		No NQC - est. data	Solar
SDG&E	ZZZZ_New Unit	22949	BUE GEN 1_G4	0.69	0.00	1	SD-IV		Energy Only	Wind
SDG&E	ZZZZZ_CBRLLO_6_PLSTP1	22092	CABRILLO	69	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_DIVSON_6_NSQF	22172	DIVISION	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	SD-IV	San Diego, El Cajon	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA1	22233	ENCINA 1	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	SD-IV	San Diego	Retired	Market

SDG&E	ZZZZZ_ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_NIMTG_6_NIQF	22576	NOISLMTR	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_OTAY_6_LNDFL5	22604	OTAY	69	0.00		SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_6_LNDFL6	22604	OTAY	69	0.00		SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_6_UNITB1	22604	OTAY	69	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_7_UNITC1	22604	OTAY	69	0.00	3	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_PTLOMA_6_NTCCG N	22660	POINTLMA	69	0.00	2	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_PTLOMA_6_NTCQF	22660	POINTLMA	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen

Attachment 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 Factor (%)
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 Factor (%)
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

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
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 – Sierra Overall

Effectiveness factors to the Table Mountain – Pease 60 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32492	GRNLEAF2	1	17
32494	YUBA CTY	1	17
32496	YCEC	1	17
31794	WOODLEAF	1	6
31814	FORBSTWN	1	6
31832	SLY.CR.	1	6
31834	KELLYRDG	1	6
31888	OROVLENRG	1	6

Attachment B - Effectiveness factors for procurement guidance

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32451	FREC	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32452	COLGATE2	1	5
32156	WOODLAND	1	4
32498	SPILINCF	1	4
32502	DTCHFLT2	1	4
32454	DRUM 5	1	3
32474	DEER CRK	1	3
32476	ROLLINSF	1	3
32484	OXBOW F	1	3
32504	DRUM 1-2	1	3
32504	DRUM 1-2	2	3
32506	DRUM 3-4	1	3
32506	DRUM 3-4	2	3
32464	DTCHFLT1	1	3
32480	BOWMAN	1	3
32488	HAYPRES+	1	3
32488	HAYPRES+	2	3
32472	SPAULDG	1	3
32472	SPAULDG	2	3
32472	SPAULDG	3	3

Attachment B - Effectiveness factors for procurement guidance

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32462	CHI.PARK	1	3
32500	ULTR RCK	1	3
31784	BELDEN	1	3
31786	ROCK CK1	1	3
31788	ROCK CK2	1	3
31790	POE 1	1	3
31792	POE 2	1	3
31812	CRESTA	1	3
31812	CRESTA	2	3
31820	BCKS CRK	1	3
31820	BCKS CRK	2	3
32478	HALSEY F	1	2
32512	WISE	1	2
32460	NEWCSTLE	1	2
32510	CHILIBAR	1	2
32513	ELDRADO1	1	2
32514	ELDRADO2	1	2
32456	MIDLFORK	1	2
32456	MIDLFORK	2	2
32458	RALSTON	1	2
32486	HELLHOLE	1	2
32508	FRNCH MD	1	2
38114	STIG CC	1	1
38123	LODI CT1	1	1

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
38124	LODI ST1	1	1

Table – San Jose

Effectiveness factors to the El Patio-San Jose 'A' 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	36
36863	DVRaGT1	1	13
36864	DVRbGt2	1	13
36865	DVRaST3	1	13
36859	Laf300	2	13
36859	Laf300	1	13
36856	CCA100	1	13
36858	Gia100	1	12
36895	Gia200	1	12
35861	SJ-SCL W	1	9
35854	LECEFGT1	1	9
35855	LECEFGT2	1	9
35856	LECEFGT3	1	9
35857	LECEFGT4	1	9
35858	LECEFST1	1	9
35860	OLS-AGNE	1	9

Table – South Bay-Moss Landing

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
36209	SLD ENRG	1	20
36221	DUKMOSS1	1	20
36222	DUKMOSS2	1	20

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

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

Table – Ames/Pittsburg/Oakland

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
35304	RUSELCT1	1	10
35305	RUSELCT2	2	10
35306	RUSELST1	3	10
33469	OX_MTN	1	10
33469	OX_MTN	2	10
33469	OX_MTN	3	10
33469	OX_MTN	4	10
33469	OX_MTN	5	10
33469	OX_MTN	6	10
33469	OX_MTN	7	10
33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3
33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3

33113	LMECST1	1	3
33151	FOSTER W	1	2
33151	FOSTER W	2	2
33151	FOSTER W	3	2
33136	CCCSD	1	2
33141	SHELL 1	1	2
33142	SHELL 2	1	2
33143	SHELL 3	1	2
32900	CRCKTCOG	1	2
32910	UNOCAL	1	2
32910	UNOCAL	2	2
32910	UNOCAL	3	2
32920	UNION CH	1	2
32921	ChevGen1	1	2
32922	ChevGen2	1	2
32923	ChevGen3	3	2
32741	HILLSIDE_12	1	2
32901	OAKLND 1	1	1
32902	OAKLND 2	2	1
32903	OAKLND 3	3	1
38118	ALMDACT1	1	1
38119	ALMDACT2	1	1

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)

32741	HILLSIDE_12	1	15
32921	ChevGen1	1	15
32922	ChevGen2	1	15
32923	ChevGen3	3	15
32920	UNION CH	1	14
32910	UNOCAL	1	13
32910	UNOCAL	2	13
32910	UNOCAL	3	13
32901	OAKLND 1	1	10
32902	OAKLND 2	2	10
32903	OAKLND 3	3	10
38118	ALMDACT1	1	10
38119	ALMDACT2	1	10
33141	SHELL 1	1	9
33142	SHELL 2	1	9
33143	SHELL 3	1	9
33136	CCCSD	1	8
32900	CRCKTCOG	1	7
33151	FOSTER W	1	6
33151	FOSTER W	2	6
33151	FOSTER W	3	6
33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3
33113	LMECST1	1	3

33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3

Table – Herndon

Effectiveness factors to the Herndon-Manchester 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
34624	BALCH 1	1	22
34616	KINGSRIV	1	21
34500	DINUBA	TA	19
34648	DINUBA E	1	19
34671	KRCDPCT1	1	19
34672	KRCDPCT2	1	19
34308	KERCKHOF	1	17
34344	KERCK1-1	1	17
34345	KERCK1-3	3	17
34690	CORCORAN_3	FW	15
34692	CORCORAN_4	FW	15
34677	Q558	1	15
34696	CORCORANPV_S	1	15
34610	HAAS	1	13
34610	HAAS	2	13
34612	BLCH 2-2	1	13
34614	BLCH 2-3	1	13

34431	GWF_HEP1	1	8
34433	GWF_HEP2	1	8
34617	Q581	1	5
34680	KANSAS	1	5
34467	GIFFEN_DIST	1	4
34563	STROUD_DIST	2	4
34563	STROUD_DIST	1	4
34608	AGRICO	2	4
34608	AGRICO	3	4
34608	AGRICO	4	4
34644	Q679	1	4
365502	Q632BC1	1	4

Table – LA Basin

Effectiveness factors to the Mesa – Laguna Bell #1 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
29951	REFUSE	D1	35
24239	MALBRG1G	C1	34
24240	MALBRG1G	C2	34
24241	MALBRG1G	S3	34
29903	ELSEG6ST	6	27
29904	ELSEG5GT	5	27
29902	ELSEG7ST	7	27
29901	ELSEG8GT	8	27
24337	VENICE	1	26

24094	MOBGEN1	1	26
24329	MOBGEN2	1	26
24332	PALOGEN	D1	26
24011	ARCO 1G	1	23
24012	ARCO 2G	2	23
24013	ARCO 3G	3	23
24014	ARCO 4G	4	23
24163	ARCO 5G	5	23
24164	ARCO 6G	6	23
24062	HARBOR G	1	23
24062	HARBOR G	HP	23
25510	HARBORG4	LP	23
24327	THUMSGEN	1	23
24020	CARBGEN1	1	23
24328	CARBGEN2	1	23
24139	SERRFGEN	D1	23
24070	ICEGEN	1	22
24001	ALAMT1 G	I	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24005	ALAMT5 G	5	18
24161	ALAMT6 G	6	18
90000	ALMT-GT1	X1	18
90001	ALMT-GT2	X2	18

90002	ALMT-ST1	X3	18
29308	CTRPKGEN	1	18
29953	SIGGEN	D1	18
29309	BARPKGEN	1	13
29201	WALCRKG1	1	12
29202	WALCRKG2	1	12
29203	WALCRKG3	1	12
29204	WALCRKG4	1	12
29205	WALCRKG5	1	12
29011	BREAPWR2	C1	12
29011	BREAPWR2	C2	12
29011	BREAPWR2	C3	12
29011	BREAPWR2	C4	12
29011	BREAPWR2	S1	12
24325	ORCOGEN	I	12
24341	COYGEN	I	11
25192	WDT1406_G	I	11
25208	DowlingCTG	1	10
25211	CanyonGT 1	1	10
25212	CanyonGT 2	2	10
25213	CanyonGT 3	3	10
25214	CanyonGT 4	4	10
24216	VILLA PK	DG	9

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

Attachment B - Effectiveness factors for procurement guidance

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
22982	TDM CTG2	1	25
22983	TDM CTG3	1	25
22981	TDM STG	1	25
22997	INTBCT	1	25
22996	INTBST	1	25
23440	DW GEN2 G1	1	25
23298	DW GEN1 G1	G1	25
23156	DU GEN1 G2	G2	25
23299	DW GEN1 G2	G2	25
23155	DU GEN1 G1	G1	25
23441	DW GEN2 G2	1	25
23442	DW GEN2 G3A	1	25
23443	DW GEN2 G3B	1	25
23314	OCO GEN G1	G1	23
23318	OCO GEN G2	G2	23
23100	ECO GEN1 G	G1	22
23352	ECO GEN2 G	1	21
22605	OTAYMGT1	1	18
22606	OTAYMGT2	1	18
22607	OTAYMST1	1	18
23162	PIO PICO CT1	1	18
23163	PIO PICO CT2	1	18
23164	PIO PICO CT3	1	18

22915	KUMEYAAY	1	17
23320	EC GEN2	1	17
22150	EC GEN1	1	17
22617	OY GEN	1	17
22604	OTAY	1	17
22604	OTAY	3	17
22172	DIVISION	1	17
22576	NOISLMTR	1	17
22704	SAMPSON	1	17
22092	CABRILLO	1	17
22074	LRKSPBD1	1	17
22075	LRKSPBD2	1	17
22660	POINTLMA	1	17
22660	POINTLMA	2	17
22149	CALPK_BD	1	17
22448	MESAHGTS	1	16
22120	CARLTNHS	1	16
22120	CARLTNHS	2	16
22496	MISSION	1	16
22486	MEF MR1	1	16
22124	CHCARITA	1	16
22487	MEF MR2	1	16
22625	LkHodG1	1	16
22626	LkHodG2	2	16
22332	GOALLINE	1	15

22262	PEN_CT1	1	15
22153	CALPK_ES	1	15
22786	EA GEN1 U6	1	15
22787	EA GEN1 U7	1	15
22783	EA GEN1 U8	1	15
22784	EA GEN1 U9	1	15
22789	EA GEN1 U10	1	15
22257	ES GEN	1	15
22263	PEN_CT2	1	15
22265	PEN_ST	1	15
22724	SANMRCOS	1	15
22628	PA GEN1	1	14
22629	PA GEN2	1	14
22082	BR GEN1	1	14
22112	CAPSTRNO	1	12

Attachment D

California ISO

Resource Adequacy Enhancements
Fifth Revised Straw Proposal

July 7, 2020

Resource Adequacy Enhancements

Fifth Revised Straw Proposal

July 7, 2020

Table of Contents

1. Executive Summary

The California Independent System Operator Corporation (CAISO) is performing a comprehensive review of the CAISO's Resource Adequacy (RA) tariff provisions and proposing enhancements that ensure effective procurement of capacity to reliably operate the grid all hours of the year. This comprehensive review has identified potential modifications to the CAISO tariff provisions for System, Local, and Flexible RA.

The CAISO's fifth revised straw proposal considers enhancements to RA counting rules and assessments. This includes considering methodologies for determining forced outage rates for system, local, and flexible RA requirements. It is common practice among other independent system operators (ISOs) and regional transmission organizations (RTOs) to include an assessment of unforced capacity values that relies on the probability a resource will experience a forced outage or derate at some point when it has been procured for RA capacity. The CAISO proposes to develop a methodology for calculating unforced capacity values and a portfolio assessment to ensure the shown RA capacity is collectively adequate to meet the CAISO's operational needs in all hours. The CAISO believes this proposed portfolio assessment is necessary to address the growing reliance on use- and availability-limited resources as part of the RA fleet. The CAISO is proposing to develop a stochastic production simulation model that assesses the RA fleet's ability to reliably operate the grid under a variety of conditions.

Regarding provisions for RA must offer obligations and bid insertion, the CAISO is proposing modifications to ensure coordination with the Day Ahead Market Enhancements and Extended Day-Ahead Market initiatives. This coordination is key to ensure all three proposals work without conflicting outcomes. To align with the CAISO's Day-Ahead Market Enhancements initiative, RA resources will have a 24 by 7 must offer obligation into the day-ahead market unless explicitly provided an exemption to this requirement through the proposed policy modifications. The CAISO also proposes that RA resources are subject to bid insertion, unless exempted.

The CAISO is proposing several changes to the existing planned outage provisions and the planned outage process. In response to stakeholder feedback, several changes are intended to provider higher assurance that planned outages scheduled by 45 days prior to the month actually can be taken when scheduled. The CAISO proposes to redesign the planned outage process to reflect system UCAP targets rather than traditional NQC targets. This proposal includes a process that accounts for the need for planned outages in the upfront procurement and eliminates the need for all planned outage substitution. Under this proposal, the CAISO will (1) eliminate RAAIM, and (2) retain complete discretion to grant or deny all opportunity outages. The CAISO previously considered a second option, under which the CAISO would procure all substitute capacity on behalf of resources seeking planned outages. The CAISO is no longer considering this option due to numerous complexities involved with such a proposal.

The CAISO proposes modifications to the RA import provisions. The SC for the RA resource will be required to submit supporting documentation demonstrating that any RA import resource shown on annual and monthly Supply plans represent physical capacity that has not been sold or committed to any other entity for the applicable RA period. The CAISO will include these requirements in the tariff to ensure similar treatment among all LSEs and RA import suppliers.

The CAISO will require that all RA imports, at minimum, identify the source BA and resource or aggregation or portfolio of resources within a single BAA that will provide the capacity. This will ensure that RA imports are not double counted for EIM entities' resource sufficiency tests or otherwise relied upon by the host BAA to serve native load. The CAISO is also considering whether to require firm transmission for RA imports form source-to-sink or only requiring firm transmission delivery on the last line of interest (last leg) to the CAISO BAA, as shown a day-ahead e-Tag, or the requirement of having one of these two options.[1]

The CAISO is proposing a new flexible RA framework that more deliberately captures the CAISO's operational needs for unpredictable ramping needs between day-ahead and real-time markets. Proposed changes to the flexible capacity product and flexible capacity needs determination are intended to closely align with CAISO's actual operational needs for various market runs (*i.e.*, day-ahead market and fifteen-minute market). The proposal also incorporates Effective Flexible Capacity (EFC) counting rules and allowing imports to qualify to meet flexible RA requirements. CAISO also proposes rules for allocation of identified flexible RA needs, updated showings and assessments rules, and updated Must Offer Obligations for flexible RA capacity.

Regarding local RA modifications, the CAISO is examining incorporating forced outage rates into the local RA process.

The CAISO is proposing modifications to its backstop capacity procurement provisions to align backstop authority with the resource adequacy counting rules and adequacy assessments. These proposed modifications include new procurement authority to use the capacity procurement mechanism as an option to fulfill load serving entities' unforced capacity deficiencies and system deficiencies as determined through a resource adequacy portfolio showing analysis. The CAISO is seeking feedback on potential changes for that could be made for incentivizing performance for RMR resources. The CAISO is also seeking authority for a tool to incentivize load serving entities to show UCAP capacity up to requirements.

2. Introduction and Background

The rapid transformation to a cleaner, yet more variable and energy limited resource fleet, and the migration of load to smaller and more diverse load serving entities requires re-examining all aspects of the CAISO's Resource Adequacy program. In 2006, at the onset of the RA program in California, the predominant energy production technology types were gas fired, nuclear, and hydroelectric resources. While some of these resources were subject to use-limitations because of environmental regulations, start limits, or air permits, they were generally available to produce energy when and where needed given they all had fairly dependable fuel sources.

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[1] The obligations for resource specificity and firm transmission fall to the SC for the RA import based on their contractual arrangement.

However, as the fleet transitions to achieve the objectives of SB 100,[2] the CAISO must rely on a very different resource portfolio to reliably operate the grid. In this stakeholder initiative, the CAISO, in collaboration with the California Public Utilities Commission (CPUC) and stakeholders, will explore reforms needed to the CAISO's resource adequacy rules, requirements, and processes to ensure continued reliability and operability under the transforming grid.

The CAISO has identified certain aspects within the CAISO's current RA tariff authority that, among other things, require refinement to ensure effective procurement, help simplify overly complex rules, and ensure resources are available when and where needed all hours of the year. The following issues are of growing concern to the CAISO:

- Current RA counting rules do not adequately reflect resource availability, and instead rely on complicated substitution and availability incentive mechanism rules;
- Flexible capacity counting rules do not sufficiently align with operational needs;
- Provisions for import resources need clarification to ensure physical capacity and firm delivery from RA imports;
- Current system and flexible RA showings assessments do not consider the overall effectiveness of the RA portfolio to meet the CAISO's operational needs; and
- Growing reliance on availability-limited resources when these resources may not have sufficient run hours or dispatches to maintain and serve the system reliably and meet energy needs in local capacity areas and sub-areas.

The CAISO is conducting a holistic review of its existing RA tariff provisions to make necessary changes to ensure CAISO's RA tariff authority adequately supports reliable grid operations into the future.

[2] The objective of SB 100 is "that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045."
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

3. Stakeholder Engagement Plan

Table 1 outlines the schedule for this stakeholder initiative below. The CAISO plans to seek CAISO board approval of the elements in this RA Enhancements initiative in the first quarter of 2021.

Table 1: Stakeholder Engagement Plan

Date	Milestone
July 7	**Fifth revised straw proposal**
July 14-16	Stakeholder meeting on fifth revised straw proposal
July 30	Stakeholder comments on fifth revised straw proposal due
Oct 12	**Draft final proposal**
Oct 19-20	Stakeholder meeting on draft final proposal
Nov 3	Stakeholder comments on draft final proposal
Aug – Q1 2021	Draft BRS and Tariff
Q1 2021	**Final proposal**
Q1 2021	**Present proposal to CAISO Board**

4. RA Enhancements Fifth Revised Straw Proposal

The following sections detail the CAISO's proposed modifications and provide the CAISO's rationale and supporting justification. The CAISO has organized the Fifth Revised Straw Proposal into sections covering System, Flexible, and Local RA and related sub topics, and a section covering proposed modifications to the CAISO's backstop procurement provisions. In its Second Revised Straw Proposal, the CAISO separated two local RA topics from previous versions into a separate draft final proposal.[3]

The RA Enhancements Fifth Revised Straw Proposal covers the following topics. This list also includes a summary of major changes from previous proposals:

- System Resource Adequacy
  - Determining System RA Requirements
  - Unforced Capacity Evaluations
    - Modifications - Updated outages definitions, forced outage exemption process. Modified seasonal availability calculation to include top 20% tightest supply cushion hours. Added UCAP calculations for storage and hydro. Added transition plan options for stakeholder consideration.
  - System RA Showings and Sufficiency Testing
  - Must Offer Obligation and Bid Insertion Modifications
    - Modifications - Added additional detail to day-ahead must offer obligation alignment with Day-Ahead Market Enhancements initiative. Minor updates to the variations to the standard must offer obligation for specific resource types.
  - Planned Outage Process Enhancements
    - Modifications – Added additional detail and justification for establishing a planned outage reserve margin in non-summer months.
  - RA Import Provisions
    - Modifications – Modified definition of source specification to include specific units or aggregation of units only. Added details to the resource specification proposal.
    - Considering maintaining firm transmission from source to sink but introducing an alternative option of only requiring firm transmission service on the last line of interest to CAISO BAA with a minimum day-ahead e-tagging requirement.
  - Operationalizing Storage Resources
    - Modifications – Additional detail and clarifications added.
- Flexible Resource Adequacy – remains on-hold; no new additions to this section
- Local Resource Adequacy

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[3] Draft Final Proposal for Local Assessments with Availability Limited Resources and Final Proposal for Meeting Local Needs with Slow Demand Response can be found on the RA Enhancements and Proxy Demand Resource - Resource Adequacy Clarifications Webpage:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx,
http://www.caiso.com/StakeholderProcesses/Proxy-demand-resource-resource-adequacy-clarification

    - UCAP in Local RA Studies
- Backstop Capacity Procurement Provisions
    - Capacity Procurement Mechanism Modifications
    - Making UCAP Designations
    - Reliability Must-Run Modifications
    - UCAP Deficiency Tool

4.1. System Resource Adequacy

Resource deliverability under stressed system conditions remains an essential and important part of a resource's ability to support reliable grid operations, and the CAISO intends to preserve the current NQC calculations for resources, *i.e.*, the CAISO will continue to perform NQC calculations exactly as it does today, and will continue to derate Qualifying Capacity values (QC) based on deliverability.[4]

For all resources with NQC values, the CAISO proposes to establish UCAP values to identify the unforced capacity value (NQC discounted for units' forced outage rates) for use in system, local, and flexible RA showings and assessments.[5] The UCAP value speaks to the quality and dependability of the resources procured to meet RA requirements. The CAISO also proposes to establish system RA requirements and associated sufficiency tests that account for unit forced outage rates. In other words, a resource's RA value should be measured in terms of its UCAP value, and individual LSE sufficiency tests should be measured based on meeting UCAP requirements each month. The following section provides the CAISO's proposed modifications to incorporate these changes into CAISO RA processes and tariff.

4.1.1. Determining System RA Requirements

The CAISO proposes that RA accounting should reflect both NQC and UCAP values. The CAISO will coordinate with the CPUC and LRAs to ensure alignment with individual LRA requirements.

The following discussion represents the initial proposal of the CAISO. <u>This section remains unchanged from the Fourth Revised Straw Proposal. However, the CAISO is conducting an assessment of actual June RA showings using stochastic production simulation. This production simulation was originally designed to demonstrate the capabilities needed to conduct an RA portfolio assessment. However, the CAISO believes that such a study will also provide additional context about how UCAP requirements should be established.</u> As a result, the CAISO will issue a supplement to this straw proposal in mid-August. This supplement will include details regarding the inputs used in the assessment, the outcome of the assessment in terms of probabilities of stage emergencies and unserved energy. Based on this assessment, the CAISO make additional updates and recommendations regarding how best to set UCAP requirements.

[4] Section 4.1.2 describes two options for transitioning to the UCAP construct to minimize implementation complexity for the CAISO and participants. Option 1 would modify the terminology of NQC but the process would remain unchanged.
[5] Resources without an NQC are not eligible to provide system or local RA capacity.

System UCAP Requirement

From a planning perspective, it is reasonable to require that the amount of UCAP made available should be sufficient to serve forecasted peak load and ancillary services requirements given the forced outage rate of resources is embedded in the UCAP value. After removing forced outages from the planning reserve margin, what remains is forecast error and ancillary services. When the RA program was originally developed, the estimated forced outage rate for RA resources was approximately 4% to 6% of the 15% planning reserve margin. Unfortunately, as noted in greater detail below, the CAISO observes forced outage rates far exceeding these values at critical times. The inference drawn from this is that the current PRM, after accounting for such high forced outages rates, is insufficient to cover load, forecast error, and operating reserves during key times, jeopardizing reliability and not meeting a "good utility practice" standard.

To address these concerns, the CAISO is proposing a system UCAP requirement to more directly account for forced outages. To ensure resource adequacy, the CAISO must carry operating reserves for three percent of load and three percent of generation, or cover the Most Severe Single Contingency according to BAL-002-WECC-2a,[6] and must have sufficient RA capacity to provide regulation and the flexible ramping product. Therefore, CAISO proposes to develop a minimum system UCAP requirement that all LSEs must meet and show as RA under the CAISO tariff.

The current system RA structure is designed to cover peak forecasted load, operating reserves, forced outages, and demand forecast error. It is reasonable to assess how well the current program achieves those objectives. The CAISO analyzed data from its Customer Interface for Resource Adequacy (CIRA) system. The goal of this analysis was to assess how well the RA requirements would meet peak forecasted load, operating reserves, and forced outages. Forecast error was excluded from the assessment. The CAISO used the RA requirements for May 2018 through July 2019 based on the CEC 1-in-2 peak load forecast. The CAISO added six percent to that number to account for required operating reserves. Then, the CAISO compared that value to the available RA capacity. Available RA capacity is defined as shown RA capacity plus credits[7] minus forced outages. This analysis was conducted at a daily granularity.[8] As shown in Figure 1, there are several days that the CAISO would have been unable to cover CEC forecasted peak demand plus operating reserves. This is shown by observations below zero on the vertical axis. More specifically, on just over 17.5 percent of the days, CAISO would not have adequate RA capacity to meet its planning targets. Further, this assumes that 100 percent of all RA credits are available at the fully credited level, including over 1000 MW of credited demand response in all but one month (which was 950 MW). For

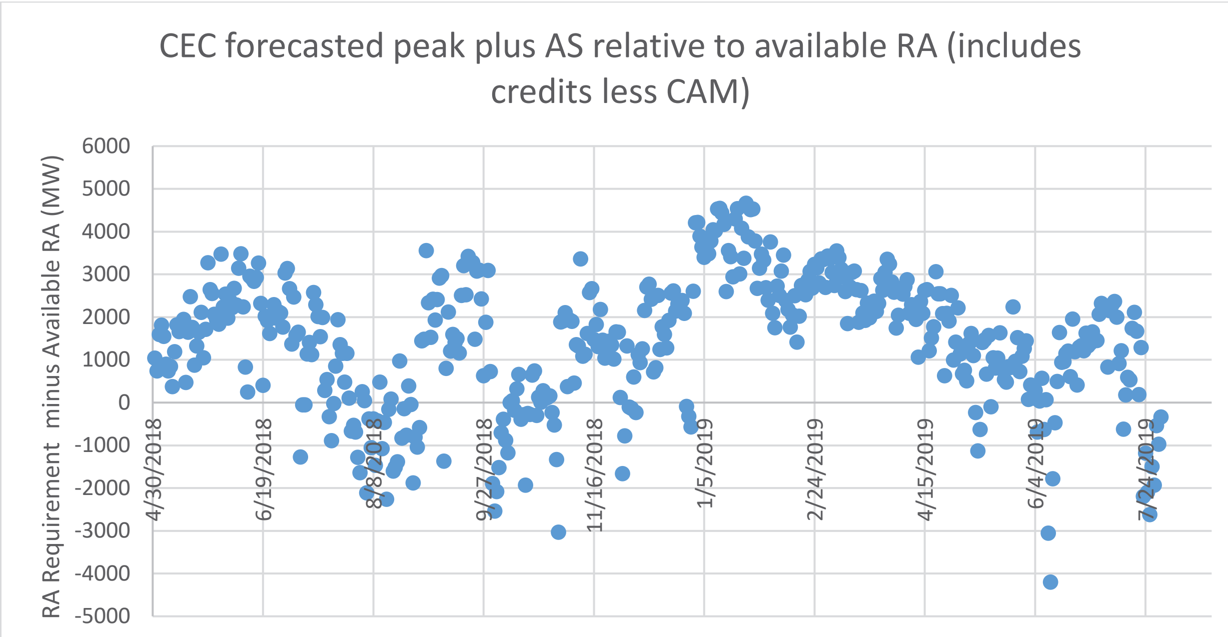
[6] BAL-002-WECC-2a found here: https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-002-WECC-2a&title=Contingency%20Reserve&jurisdiction=United%20States

[7] CAM credits were excluded from this analysis to avoid double counting.

[8] CIRA only captures when a forced outage flag has been inserted for a day. Hourly granularity is not available in CIRA.

example, if 500 MW of credited capacity is not available or was not responsive for any reason, the percent of days the CAISO would be deficient increases to 25 percent.

Figure 1: Available capacity relative to forecasted need



Additionally, the CAISO looked at the coincidence of forced outages rates with high load days. The CAISO wanted to see if forced outage rates differed based on actual load. Figure 2 shows the forced rates from May 1, 2018 through December 31, 2018. Additionally, the highest load days in each month have been isolated as well. This figure shows there is only a very slight reduction in the forced outage rates on high load days meaning there is very little difference between forced outage rates based on load levels. Put another way, a planning reserve margin should assume forced outage rates are the same regardless of load. Figure 2 shows forced outage rates regularly in excess of ten percent, and even exceeding 15 percent on multiple occasions, including higher load days. This means that any LRA setting a planning reserve margin that accurately and thoroughly accounts for forced outages should include at least a 10-15 percent range on top of the forecasted peak demand. This is further demonstrated by the distributions shown in Figure 3, which shows the maximum, minimum, and average forced outage rates for each month.[9]

[9] Additional assessments regarding the RAAIM and its effectiveness at incentivizing forced outage replacement capacity is provided in section 8.3. If RAAIM is working effectively, it would likely reduce the overall need for UCAP values. However, as shown below, it has not been very effective at incentivizing replacement capacity.

Figure 2: Forced outages relative to monthly high load days (2018 only)

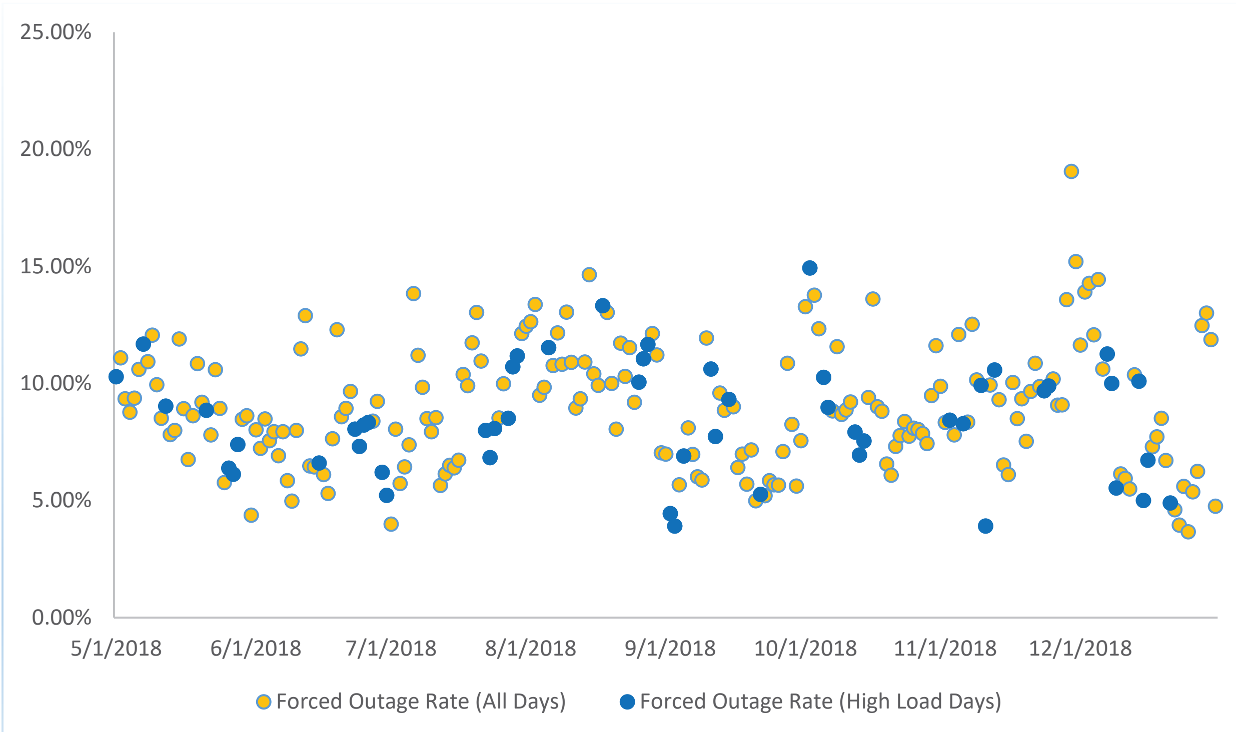
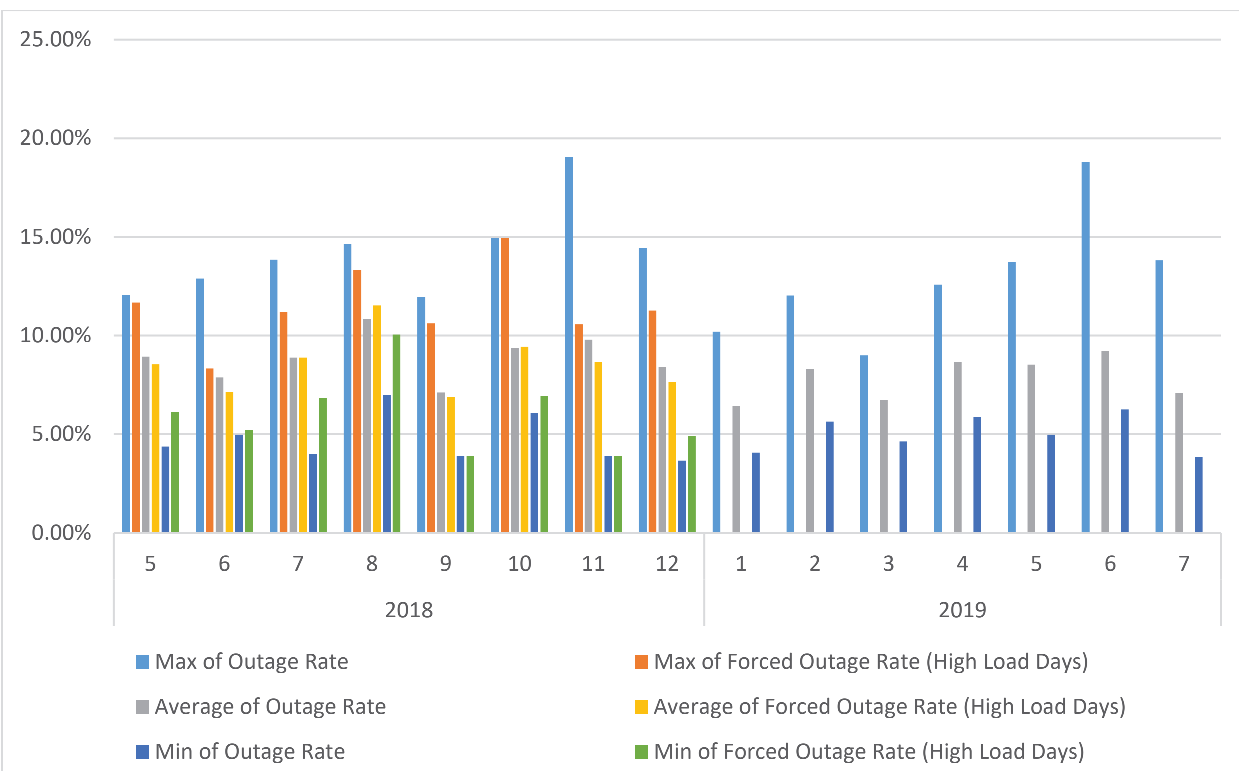


Figure 3: Distributions of Forced Outage Rates



CAISO examined two options to establish the minimum amount of UCAP required to maintain reliable grid operations: Top-down and bottom-up. The top down assumes all units in a given tech type will have the same average forced outage rate while the bottom up examines each unit individually.

The top-down approach relies on developing a probabilistic model to determine how much installed capacity must be procured to reach a predetermined loss of load expectation. This installed capacity value is then translated to an estimated UCAP requirement. This study can be conducted using either individual or system average forced outage rates. Top-down approaches that use system wide average forced outage rate rely heavily on the assumption that forced outage rates are homogenous within a technology type. As shown, this assumption may not hold in California under greater scrutiny. Large variances in the forced outage rates within a technology type can lead to inefficient capacity procurement. Further, this type of study has not been applied to a system as reliant on variable and energy-limited resources as is the CAISO's. Studies that rely on individual forced outage rates still have to account for the various permutations of outages that occur to derive the estimated UCAP requirement.

The bottom-up approach is built on the foundation of forecasted peak demand. From there, ancillary services are added. However, unlike the top down approach, the bottom-up approach does not rely on any assumptions about average forced outage rates for various technology types. Only individual resource outage rates are needed and then only for procurement and showing purposes. Therefore, average forced outage rates are not used since this information is embedded in the UCAP values.

On balance, the CAISO believes the bottom-up approach is best to establish a minimum system RA requirement based on UCAP because it helps ensure minimum resource adequacy requirements are achieved to maintain reliability given the growing number of LRAs and the potential variance in the LRAs' PRM targets. A RA requirement based on UCAP should also help mitigate the potential for capacity leaning among LSEs.

In comments to the revised straw proposal, the CPUC staff suggested using either a higher planning reserve margin or a more conservative load forecast (*i.e.*, 1-in-5 instead of 1-in-2) as an alternative solution to UCAP. As noted in CAISO's testimony in the CPUC's RA proceeding, the CAISO supports using the more conservative 1-in-5 load forecast, particularly for the shoulder months where the CAISO observes greater variability in the monthly peaks.[10] Utilizing higher load forecast would ensure more diverse load profiles can be addressed by RA procurement. However, such a change does not address the fundamental and underlying issue of incorporating forced outages upfront in the procurement process.[11]

Based on the data reviewed by the CAISO, to avoid deficiencies caused by forced outages, all LRAs must provide ancillary services to ensure six percent operating reserves based on forecasted peak demand, plus an additional 10-15 percent to reasonably address forced

[10] http://www.caiso.com/Documents/Jul10_2018_RAProceedingTrack2Testimony-Chapter4-SystemRADemandForecasts_ProposalNo3_R17-09-020.pdf

[11] These tools may provide more capacity to the CAISO but they do not ensure the quality and reliability of that capacity.

outages. The results of CAISO's analysis show that a planning reserve margin of at least 20 percent is needed to address all needs, including peak demand, forced outages, and operating reserves. This excludes forecast error, which, at least in part, can be addressed by using a 1-in-5 peak load forecast. However, this may not provide adequate RA capacity in many years. For example, using a 1-in-10 year forecast for planning purposes should cover all reasonably foreseeable procurement needs, avoiding the need to include forecast error in a planning reserve margin. Alternatively, using a 1-in-2 forecast would require that virtually all under-forecasting error be included in the planning reserve margin.

Therefore, the CAISO recognizes that efforts to establish a minimum UCAP requirement needs additional collaboration with LRAs to address under-forecasting risks. At this time, CAISO believes that the UCAP requirement should be set at a minimum of 110 percent of forecasted peak. This number accounts for forecast load, reserves, and forecast error. The value used for the forecast error is derived from comparing the low, mid, and high load forecasts from the CEC's 2018 final Integrated Energy Policy Report (IEPR).[12] The IEPR mid load forecast was approximately between one to three percent higher than the low load forecast. The high load forecast was between four and seven percent higher. To account for forecast error, the planning reserve margin likely would need an additional two to six percentage points. The CAISO has selected four percent as a reasonable starting point.

The CAISO received stakeholder feedback indicating a need for the CAISO to consider how to coordinate these important system RA modifications with the CPUC's RA program and with other LRAs. The CAISO agrees this is an important consideration. For a detailed discussion on matters related to coordination of the proposed UCAP concepts with the CPUC's programs, please see section 4.1.2.

4.1.2. Unforced Capacity Evaluations

The CAISO is proposing to adopt provisions for evaluating the reliability and availability of resources that account for the probability of forced outages and derates. This proposed evaluation will eliminate the need for complicated assessments of availability and replacement capacity rules. Many of the U.S. Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) utilize an Installed Capacity (ICAP) and Unforced Capacity (UCAP) concept. ICAP values generally account for resource capacity impacts caused by ambient weather conditions and represents physical generating capacity. UCAP is a percent of the ICAP available once outages are taken into consideration. NYISO, PJM, and MISO incorporate forced outages when calculating each resource's qualifying capacity value and measure capacity value using UCAP in their respective markets. In contrast, ISO-NE relies on an ICAP value that incorporates historical forced outage data when establishing its Installed Capacity Requirement.

The methodological assumptions for calculating UCAP values vary somewhat among system operators and the criteria inputs are unique for each resource type. Generally, UCAP incorporates the availability of a resource using a derating or availability factor. There are

[12] 2018 Integrated Energy Policy Report found here: https://ww2.energy.ca.gov/2018_energypolicy/

several key advantages to integrating forced outages and derates into a generator's calculated RA qualifying capacity value. Recognizing a unit's contribution to reliability enables one to compare its reliability to other resources by accounting for differences in forced outage rates. Greater resource accountability should produce market signals that promote procurement of better performing resources with improved operational reliability and availability. The accessibility of information on the forced outages and derates of resources that impact their availability can help buyers avoid risks and make better informed decisions when making bilateral trades or procuring replacement RA capacity.

To date, neither the CAISO nor the CPUC account for the impact forced outages and unit derates have on system reliability beyond what is minimally assured in the established planning reserve margin requirement. Instead, the CAISO relies on substitution rules and the Resource Adequacy Availability Incentive Mechanism (RAAIM) to discipline capacity availability on the very back-end, *i.e.*, the operational end of the process. RAAIM calculates incentive payments and resource non-availability charges based on a resource's bidding behavior. RAAIM is intended to incentivize compliance with bidding and must-offer obligations and ensure adequate availability of RA resources. However, the CAISO believes that confirmation that RA capacity will be available, or be replaced if unavailable, occurs inappropriately late. The dependability and reliability attributed to all resources should be better known and understood upfront during the RA procurement process.

The CAISO proposes to calculate and publish monthly NQC and UCAP values for all resources annually (*i.e.*, once per year a unit will get a distinct NQC and UCAP value for each month of the upcoming year).[13] The NQC process will remain similar to the current approach with no major proposed changes. The CAISO proposes that the calculation of each resource's UCAP will be limited at a resource's NQC value and will consider the resource's forced and urgent outages and derates in determining a resource's UCAP value. The CAISO proposes to calculate seasonal availability factors for UCAP determination purposes. The CAISO proposes to utilize two seasons for this availability factor determination, on-peak (summer) and off-peak (winter). UCAP values will not be affected by CAISO approved planned or opportunity outages. The CAISO will calculate UCAP values for all resource types that do not rely on an LRA established Effective Load Carrying Capability (ELCC) methodology for determining QC values. For resources with QC values calculated using an ELCC methodology, the CAISO will use the ELCC value as the UCAP value. The CAISO provides more discussion regarding the basis for this treatment below.

Outage Definitions

The first and primary input needed to calculate a resource's UCAP value is accurate and appropriate forced outage and derate data. The seasonal availability factor counting methodology proposed below will be based upon a resource's forced and urgent outages and derates during the tightest system supply condition hours. This outage and derate data is the

[13] Given the relationship between NQC and UCAP, while a resources' Weighted Average Availability Factors will only be calculated on an annual basis, if a resource's NQC value increases mid-year, as allowed under the existing tariff, the CAISO will update the resource's NQC and UCAP value accordingly.

key information necessary to calculate the expected value (in terms of MWs) of a capacity resource's unforced capacity.

Today, the CAISO has numerous outage cards in the CAISO Outage Management System (OMS) that are designed to describe the nature of work for resource outages. The CAISO also uses these outage cards to determine whether a resource must provide substitute capacity to avoid RAAIM charges, or if the outage is beyond the resource's control and therefore RAAIM exempt. However, the CAISO has encountered challenges utilizing the OMS as currently configured. More specifically, the OMS system is not currently designed to generate and store historical forced outage rates.

Given these challenges, the CAISO considered how best to collect and store data to calculate forced outage rates. The CAISO efforts can be broken down into two objectives: (1) transitioning to UCAP, and (2) longer term outage collection and reporting. The CAISO proposes here a solution that aligns the outage reporting in CAISO systems for the CAISO as the balancing authority with the outage reporting for the Reliability Coordinator (RC) outage coordination process. The CAISO believes this approach will facilitate a smooth transition to UCAP because CAISO systems already classify outages this way for RC purposes and simplify outage classification for the purposes of calculating forced outage rates. Additionally, this approach offers benefits beyond those related to UCAP, as aligning the definitions with the RC definitions will provide clarity and minimize confusion stemming from multiple outage definitions. The remainder of this subsection provides additional details regarding the CAISO's efforts to align CAISO balancing authority area outage definitions with those adopted by the CAISO's reliability coordinator, transition to UCAP, and then ensure accurate long term outage reporting.

In Reliability Coordinator Procedure RC0630, the CAISO defines outage types, their priorities, and the study windows with timelines for outage submission.[14] The following are outages taken by generating resources:

> *Forced Outage* – Facility/equipment that is removed from service real-time with limited or no notice
>
> *Urgent Outage* – Facility/equipment that is known to be operable, yet carries an increased risk of a Forced outage occurring. Facility/equipment remains in service until personnel, equipment and/or system conditions allow the outage to occur. Urgent outages allow Facilities to be removed from service at an optimal time for overall system reliability. For Urgent outages, the work may or may not be able to wait for the Short-Range outage window.
>
> *Planned Outage* – Facility/equipment outage with enough advance notice to meet short range submittal requirements.[15]

[14] RC Procedure RC0630, p13-15: http://www.caiso.com/Documents/RC0630.pdf.
[15] Outage management BPM Section 7.2 describes the short range outage submittal requirements for planned outages for the CAISO BAA.

> Opportunity Outage – A Facility/equipment outage that can be taken due to a change in system conditions, weather or availability of field personnel. Opportunity outages did not meet the short range window requirements.

The following outage types are for transmission equipment or outages that do not affect the output of the generator. These outages would not be included in the resource's UCAP value because they do not indicate reduced availability of a generator. The CAISO proposes to incorporate these definitions into the CAISO BA outage process to ensure full alignment in outage definitions between CAISO BA and the RC, beyond just those used for generation availability, and their associated UCAP determinations.

> Operational Outage – Transmission Facility/equipment that is removed from service in the normal course of maintaining optimal or reliable system conditions but remains available if needed upon short notice. (This outage type may be either planned or real-time. Work is not being performed on the equipment/facility, but may be part of an operating plan.)

> Informational Outage – Facility/equipment outage that is entered for informational reasons including increased situational awareness, for BA/TOP internal purposes or to satisfy the RC Data Specification where WebOMS is the mechanism for communicating the information.

The CAISO is not proposing any changes to the RC outage definitions or outage coordination process in this initiative. Instead, the CAISO proposes to align its CAISO BA outage definitions with the RC outage definitions. For the purposes of UCAP, CAISO proposes forced and urgent outages will be considered in a resource's forced outage rate calculation. Approved planned and opportunity outages will not be considered in a resource's forced outage rate calculation. Additional details on how forced outage rates will be used to calculate UCAP values are described in detail below. Finally, the CAISO proposes to reconfigure its OMS system or to develop an alternative system to accurately track and store resources' forced outages and derates to generate resource specific UCAP values.

UCAP Exemption Process for Rare Events

The CAISO's review of some other ISOs/RTOs show there are several approaches for determining which outages to include in the outage rate of the resource for the UCAP calculation. MISO includes forced outages and derates, but excludes outages caused by events deemed "outside of management control" including transmission outages, natural disasters, and fuel quality problems.[16] The NYISO exempts outages caused by equipment failure that involves equipment located beyond the generator and including the step up transformer. The exemption

[16] BPM 011 – Resource Adequacy, MISO: https://www.misoenergy.org/legal/business-practice-manuals/#:~:text=BPM%20011%20addresses%20MISO's%20and,have%20an%20appropriate%20reserve%20margin.

does not apply to other outages that might be classified as outside management control.[17] PJM also includes forced outages and derates, and appears to exclude only outages due to natural disasters that PJM determines have a low probability of recurrence.[18] For the 2018/2019 Delivery Year and all subsequent Delivery Years, PJM considers outages deemed to be outside of plant management control within NERC guidelines in determining the forced outage rate.[19] AESO, which uses a similar availability factor method as proposes by the CAISO, and includes all historical derates, forced outages, planned outages, and force majeure outages in availability factors with the ability for the asset owner to dispute the UCAP value calculated by AESO in certain circumstances.[20] In an effort to ensure the UCAP value reflects the true availability and reliability of a resource, the CAISO proposes here an approach most similar to PJM.

There are some rare outlier events that could cause longer duration outages with a large impact on a resource's UCAP value that would not represent the true forced outage rate of the resource. For these rare instances, the CAISO proposes an after the fact review process that would exempt large outlier events. To capture the actual forced outage rate of the resource, and ensure the UCAP values reflect the availability and reliability of RA fleet, and to limit the administrative burden of SC submittal and CAISO review, the CAISO proposes to consider only outages that are outside normal utility operations, significantly affect the resource's UCAP value, and are unlikely to recur within the same UCAP calculation period of 3 years for possible exemption.

The CAISO proposes to use the following definition of a UCAP exempt outage to determine whether the outage would be excluded from the resource's UCAP calculation.

UCAP Exempt Outage

> An outage caused by a natural disaster, act of the public enemy, war, or insurrection. The cause must occur at the plant location and directly affect operability of a generating unit for 5 consecutive days or longer, has not occurred in the previous three years, and could not be avoided through the exercise of Good Utility Practice.

Due to known conditions within California, the CAISO finds it necessary to provide additional detail regarding outages caused by fires. California has a known fire season in which it is reasonable to assume recurrence of generator outages due to nearby wildfires or PSPS events. These outages should not be subject to a UCAP exemption. They are recurring and can significantly impact the availability of the resources located in fire prone areas, thus impacting the CAISO's ability to reliably serve system load year after year. Comparatively, a generator on outage because of equipment damage due to arson would be eligible for a UCAP exemption

[17] Installed Capacity Manual, NYISO: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338
[18] Manual 22, PJM: https://www.pjm.com/-/media/documents/manuals/m22.ashx
[19] PJM Reliability Assurance Agreement, Schedule 5, Section B.
[20] 3 Calculation of Unforced Capacity (UCAP), AESO: https://www.aeso.ca/assets/Uploads/CMD-2.0-Section-3-Calculation-of-UCAP.pdf

because equipment damage from arson is unlikely to cause repeated unavailability year after year.

The CAISO selected 5 days for the outage duration threshold to limit outage exemption requests to those that could have a significant impact on the resource's UCAP value. From years 2017 to 2019, the median number of UCAP Assessment Hours per day was 4 hours for Peak Months and 5 hours for Off Peak Months, and the average number of hours across all seasons was 4.8 hours per day (see Table 4 below). Assuming 5 hours per day were assessed for UCAP, then the 5 day minimum threshold could reduce a resources availability factor by 2.45-3.4%, which when weighted could impact a resource's UCAP value by about 2%.

To ensure exemptions are only requested for outages that have a low probability of recurring, the CAISO will only review outages that have occurred once within the same three year UCAP calculation period. As described below, the CAISO will calculate forced outage rates annually, using three years of historic outage rates. Therefore, the CAISO proposes not to exempt an outage if it has occurred within the last the three years of historical forced outage data for the same reason. Doing so would undermine the intention to exclude on rare events and demonstrates that this does have a probability of reoccurrence.

UCAP exempt outages submitted by the generator's SC with sufficient justification within 30 days of the conclusion of the outage will be reviewed by the CAISO, and if approved, exempted from the UCAP calculation for the season in which the outage occurred.

In comments to the June 10th working group, stakeholders expressed concern that this proposal would penalize resources for outages outside the control of the generator. The CAISO's intent with this proposal is capturing resources' true outage rate during tightest supply conditions such that enough resources are procured to meet resource adequacy needs, considering all forced outages that occur as part of normal utility operations. All resources will be treated equally based on their availability. With rare exception, outages that affect resource availability should be incorporated into resource outage rates to ensure the CAISO has sufficient reliable, dependable resource adequacy capacity to meet the reliability needs of the system. Excluding outages that predictably occur as a part of normal operations poses reliability risks by overestimating the availability of resource adequacy resources.

Seasonal availability factor counting methodology

The CAISO has proposed, and stakeholder comments have supported, a seasonal approach to UCAP. To establish the proposed Peak and Off-Peak Months Seasonal Average Availability Factors (SAAFs) used to calculate the seasonal UCAP values for each resource, the CAISO will establish a process that includes the following steps and underlying calculations. The CAISO believes that this updated UCAP determination proposal, based on seasonal availability factors, is best applied to the following resource types: Thermal, Hydro, and Storage resources. In the next section we provide more details on modifications to the underlying methodology detailed below for Hydro and Storage resources that better captures their true availability and ensure a resource isn't double penalized.

In the 3rd revised straw proposal, the CAISO had proposed to calculate hourly availability factors for each resource during the tightest supply cushion hours in each season. Supply cushion is a measure of real-time system resource adequacy risk. A large supply cushion indicates less real-time system resource adequacy risk because more energy remains available to respond to unplanned events. A low supply cushion indicates the system has fewer assets available to react to unexpected outages or load increases, indicating a high real-time system resource adequacy risk. Evaluating the historical performance of a capacity asset during a subset of tight supply cushion hours captures the correlation of the asset's availability and capability with all other system factors that drive the tight supply cushion hours. This technique should provide a better indication of how the asset will perform in the future under similar conditions when capacity is needed.

Initially, the CAISO had proposed to evaluate a resource's availability during the top 100 tightest supply cushion hours in each season. Stakeholder comments largely did not support this approach. Stakeholders were concerned that with such a small sample size, a resource's UCAP value could be affected more heavily by randomness/ "luck factor" than a true representation of their availability. Stakeholders wanted to see additional data to further justify the selection of the number of assessment hours to include, and question why we don't look at all 8760 hours. DMM suggested we look at all 8760 and weight each hour by the supply cushion. The CAISO believes that such an approach is more complex than it needs to be. Additionally, since we are not allowing for nearly any exemptions of forced and urgent outages, an 8760 approach may over penalize a resource's UCAP value in hours when there was a low real-time system resource adequacy risk.

Today, the CAISO evaluates five RAAIM Assessment Hours, which roughly translate to 20% of all hours (including weekends).[21] Using RAAIM as a template, the CAISO now proposes to evaluate a resource's UCAP value based on the top 20% of tightest supply cushion hours. This translates to 735 hours during the Peak Months (May through September) and 1018 hours in the Off-Peak Months (October through April). The advantages to this approach are that 1) it appropriately penalizes resources for being unavailable during tight system conditions; 2) unlike RAAIM, UCAP Assessment hours can fall at any point during the operating day and thus provides better incentives to be available 24x7; 3) simpler than the EFORd methodology or weighting all hours, while still providing an accurate snapshot of a resource's true available capacity to the grid; 4) utilizing a percentage of hours rather than specific number of hours provides consistency across seasons and years.

In the 3rd revised straw proposal, the CAISO had not provided a formal definition of supply cushion. The CAISO defines supply cushion as:

$$\begin{aligned}\boldsymbol{Supply\ Cushion}\\ &= \boldsymbol{Daily\ Shown\ RA(excluding\ wind\ and\ solar) - Planned\ Outage\ Impacts}\\ &\quad \boldsymbol{- Forced\ Outage\ Impacts - Net\ Load - Contingency\ Reserves}\end{aligned}$$

[21] RAAIM calculations do not currently consider weekend. However, it is important to note that tight supply cushions may also occur on weekends. Therefore, the CAISO has included them for this assessment.

The supply cushion thus represents how much Shown RA remains after serving net load, meeting Contingency reserves, and accounting for planned and forced outages. We exclude wind and solar resources from the shown RA because their capacity value is much lower than their actual production in real-time. Also by looking at Net Load rather than Gross Load we can further account for the actual production of these variable resources. Net load values are taken from the 5-minute market, to convert the supply cushion into an hourly measure we take the average of the supply cushion of all 12 RTD intervals to represent the hourly supply cushion value.

In response to stakeholder request for further data analysis, the CAISO calculated the hourly supply cushion values for May 2018 through April 2020. CIRA provided daily shown RA and forced and planned outage impacts. Net Load data was pulled from the Production and Curtailment publically available data sets. Contingency Reserves were estimated as 6% of Gross load or 2500 MW,[22] whichever was larger. Table 2 provides the percentile distribution of the supply cushion for peak and off-peak months. A negative value indicates that in that hour there was not enough shown RA to serve net load, and cover contingency reserves, planned and forced outages. Although there was likely economic energy to cover these capacity short falls in these hours, the goal of the RA program is to ensure that the CAISO has enough capacity to meet demand. Thus by accounting for a resources forced outage rates from the beginning LSEs will be able to procure sufficient, reliable capacity to cover real time operation needs.

Table 2: Percentile distribution of average hourly supply cushion

Percentile	2018 Peak Months	2018-2019 Off-Peak Months	2019 Peak Months	2019-2020 Off-Peak Months
1.0	-3,062	-2,266	-1,584	-2,619
5.0	380	-217	3,494	-449
10.0	2,619	1,191	5,859	977
20.0	5,890	3,152	8,842	3,243
25.0	7,012	3,989	9,936	3,960
50.0	10,627	7,069	14,572	7,526
75.0	14,139	10,592	18,237	11,840
90.0	17,030	13,881	21,500	15,688
95.0	18,790	15,220	23,468	18,076
99.0	21,213	17,737	26,867	21,467
Hours	3,672	5,088	3,672	5,111

Looking at the 20th percentile we see that there is variability in the size of the supply cushion across seasons which further points to the need to calculate UCAP on a seasonal basis. In Peak Months the supply cushion during UCAP Assessment Hours ranged from 5,890 MWs and below in 2018 to 8,842 MWs and below in 2019. Whereas in Off-Peak Months the supply

[22] 2,500 MW is an estimate for the Most Severe Single Contingency.

cushion during UCAP Assessment Hours ranged from 3,152 MWs and below in 2018/2019 and 3,242 in 2019/2020.

Table 3: Distribution of UCAP Assessment Hours by Operating Hour

HE	2018 Peak Months		2018-2019 Off-Peak Months		2019 Peak Months		2019-2020 Off-Peak Months	
	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
1	4	0.54	6	0.59	18	2.45	13	1.27
2	0	0.00	2	0.20	8	1.09	2	0.20
3	0	0.00	1	0.10	4	0.54	2	0.20
4	0	0.00	1	0.10	4	0.54	1	0.10
5	0	0.00	3	0.29	7	0.95	4	0.39
6	2	0.27	12	1.18	16	2.18	20	1.96
7	4	0.54	66	6.48	19	2.59	65	6.36
8	1	0.14	51	5.01	8	1.09	46	4.50
9	0	0.00	10	0.98	5	0.68	14	1.37
10	0	0.00	5	0.49	4	0.54	7	0.68
11	0	0.00	1	0.10	3	0.41	4	0.39
12	1	0.14	0	0.00	4	0.54	1	0.10
13	6	0.82	0	0.00	7	0.95	1	0.10
14	14	1.90	3	0.29	9	1.09	2	0.20
15	23	3.13	5	0.49	13	1.77	6	0.59
16	30	4.08	11	1.08	22	2.99	15	1.47
17	38	5.17	42	4.13	27	3.67	60	5.87
18	60	8.16	102	10.02	44	5.99	116	11.35
19	93	12.65	150	14.73	82	11.16	141	13.80
20	124	16.87	169	16.60	115	15.65	146	14.29
21	126	17.14	161	15.82	117	15.92	140	13.70
22	109	14.83	126	12.38	103	14.01	121	11.84
23	72	9.80	74	7.27	66	8.98	69	6.65
24	28	3.81	17	1.67	31	4.22	27	2.64
Total	735	100.0	1018	100.0	735	100.0	1022	100.0

The CAISO was also interested when in the course of the Operating Day UCAP Assessment Hours fell. We extracted the hours that fell within the 20th percentile and tabulated the number of Assessment Hours across all 24 hours, and the results are presented in Table 3 above. As we would expect, the majority of UCAP Assessment hours fall within the evening ramp periods HE 18-22 (rough 65% of observations). In Off-Peak Months we also see a clustering of UCAP Assessment hours during the morning ramp period HE 6-9. However, there are Assessment Hours that fall outside of these two ramping periods, which further documents the need to incentivize resources to be available at all points in the operating day. Another advantage of this approach vs. RAAIM today, is that by extracting the top 20% of tightest supply cushion hours to evaluate, this will allow the UCAP values to evolve as the grid evolves and capture when conditions are actually the tightest, such as overnight or during the morning ramp period in Off-

Peak Months. This chart also demonstrates that this approach will provide a similar estimation of a resource's availability as a weighted 8760 analysis would, while also not penalizing a resource for going on outage if grid conditions were not tight. We also examined how many days had at least one UCAP Assessment Hour, and over the two year period, on average 79.3% of days were included, which is similar to RAAIM today which covers roughly 71% of days. Table 4 shows the tabulation of days in which a certain number of UCAP Assessment Hours were included. The median number of hours per day was 4 for Peak Months and 5 for Off-peak months. This is similar to the number of hours currently assessed in RAAIM. Together what these table show is that this new approach to look at the top 20% of tightest supply cushion hours rather than the top 100 will address many concerns of stakeholders that "luck" will be driving UCAP values rather than a resource's true forced outage rate. As we will see in subsequent examples, what drives a resource's UCAP value is the persistence of outages, rather than any one random outage.

Table 4: Tabulation of days by number of UCAP Assessment Hours

	2018 Peak Months		**2018-2019 Off-Peak Months**		**2019 Peak Months**		**2019-2020 Off-Peak Months**	
	# of Days	% of Days	# of Days	% of Days	# of Days	% of Days	# of Days	% of Days
0	22	14.38	36	16.98	31	20.26	65	30.52
1	5	3.27	7	3.30	6	3.92	2	0.94
2	11	7.19	5	2.36	11	7.19	5	2.35
3	24	15.69	31	14.62	16	10.46	9	4.23
4	15	9.80	25	11.79	22	14.38	7	3.29
5	24	15.69	23	10.85	19	12.42	20	9.39
6	10	6.54	25	11.79	12	7.87	22	10.33
7	9	5.88	18	8.49	2	1.31	18	8.45
8	9	5.88	8	3.77	8	5.23	34	15.96
9	6	3.92	18	8.49	11	7.19	7	3.29
10	5	3.27	9	4.25	4	2.61	6	2.82
11	5	3.27	1	0.47	1	0.65	4	1.88
12	5	3.27	0	0.00	1	0.65	6	2.82
13	2	1.31	4	1.89	0	0.00	4	1.88
14	0	0.00	2	0.94	1	0.65	1	0.47
15	0	0.00	0	0.00	1	0.65	0	0.00
16	1	0.65	0	0.00	0	0.00	0	0.00
17	0	0.00	0	0.00	1	0.65	0	0.00
18	0	0.00	0	0.00	2	1.31	1	0.47
19	0	0.00	0	0.00	2	1.31	2	0.94
20	0	0.00	0	0.00	1	0.65	0	0.00
21	0	0.00	0	0.00	0	0.00	0	0.00
22	0	0.00	0	0.00	0	0.00	0	0.00
23	0	0.00	0	0.00	0	0.00	0	0.00
24	0	0.00	0	0.00	1	0.65	0	0.00
Total	153	100.0	212	100.0	153	100.0	213	100.0

Median # of hours per day		4.00		5.00		4.00		5.00
Average # of hours per day		4.80		4.75		4.80		4.97

Stakeholder Comments:

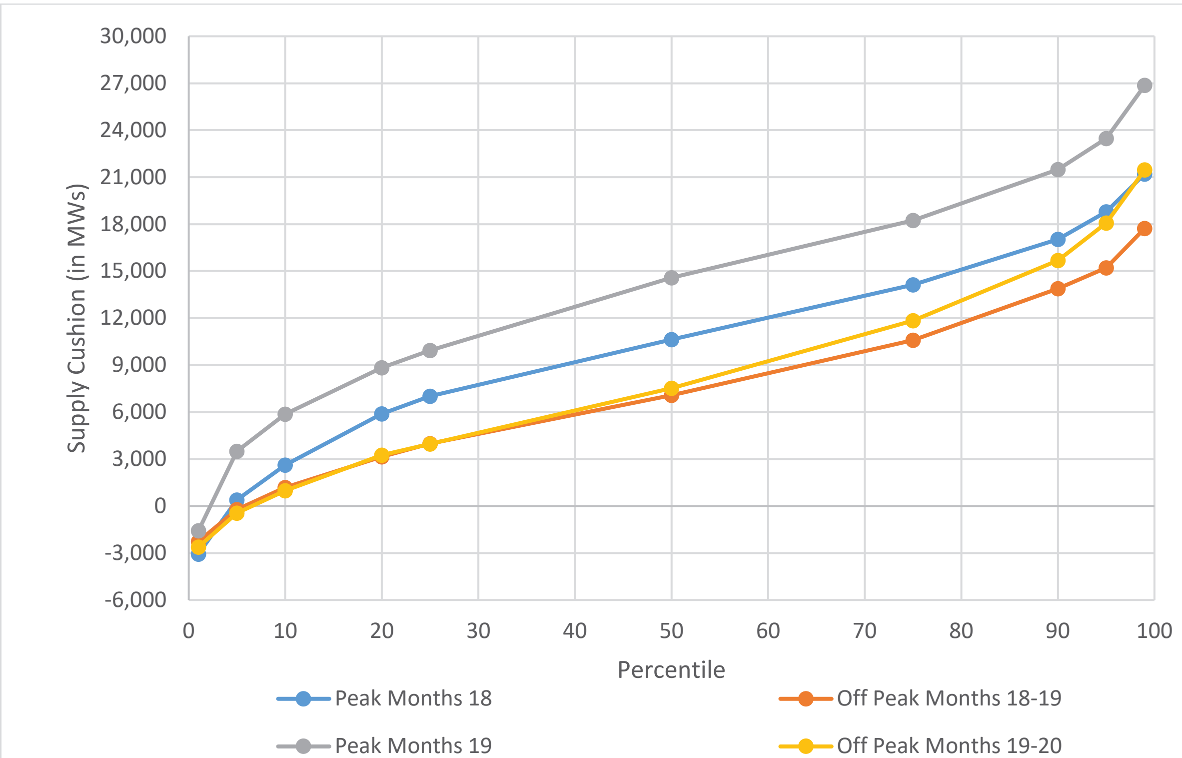
In response to the working group held on June 10th, comments submitted by stakeholders were generally more supportive of the proposal to use 20% of tightest supply cushion hours as a more reasonable approach than the top 100 hours. CalCCA requested that we calculate the UCAP value for all resources currently on the system and release information about what percentage of resources fell into certain ranges of UCAP value in order to assess the impact of this methodology. Since UCAP is still under development, the CAISO does not have the systems or resources in place to accommodate such a request. CalCCA also requested that we notify each SC of the specific UCAP value for each of their resources, which we also cannot accommodate at the moment. However, with the working group meeting, the CAISO released three example resource's UCAP calculation which identified the actual UCAP Assessment Hours for May 2018-April 2020, and so we invite SC's to utilize their own outage data to match with these published UCAP Assessment Hours, and following the steps listed below, can calculate for themselves what their resource's UCAP value would be.

Stakeholders also provided several suggestions on how to modify our proposed definition of supply cushion to identify which hours should be UCAP Assessment Hours. Calpine commented that the current formula may fail to capture periods when RA capacity is available but may not have been committed day ahead so is operationally unavailable, or may not be able to respond to changes in system conditions sufficiently rapidly. Given that majority of tight supply cushion hours fall within the evening ramping period, the CAISO does not believe that including an evaluation of committed capacity or ramping capability would significantly change which hours are deemed UCAP Assessment Hours. Additionally, with the development of Imbalance Reserves and other changes to ensure sufficient capacity is committed in the day ahead to meet uncertainty currently under development in the Day Ahead Market Enhancement Initiative, the CAISO believes that the proposed supply cushion definition will be sufficient to identify the tightest system conditions.

SDG&E suggest that we define the "tight" supply cushion hours as: Daily Shown RA PRM * Load > Daily Shown RA (excluding wind and solar) – Daily Planned Outages – Daily Forced Outage Impacts – Net Load, and evaluate UCAP based on these hours rather than a percentage of hour. The CAISO has already considered this option, and ruled it out for a number of reasons. Upon analysis, the CAISO identified that during Peak Months (May-September) there were only 248 hours in 2017, 160 hours in 2018, and 52 hours in 2019 that fellow below this threshold. The wide variety of hours will mean that the impact of a forced outage can vary wildly between years, and we could run into instances when no hours or a small subset of hours falls below this threshold, such that a resource's UCAP value could fall to zero. This would further exacerbate stakeholders concern that "luck" would drive UCAP values rather than a true representation of the resource's availability.

SCE found the 20% proposal more favorable than the top 100 hours but wanted more information about the distribution of historical outages. Figure 4 shows the distribution curves of the supply cushion for peak and off peak months. The 20th percentile was chosen more for its logical connection to the number of hours we assess for RAAIM, and sufficiently large sample size to reduce the likelihood that randomness or luck is driving UCAP values.

Figure 4: Supply Cushion Distribution Curves



Several stakeholders requested that we set the assessment hours in advance so that operators know the risks of going on forced outage. This contradicts one of the goals of moving to the UCAP paradigm, to incentivize resources to be available 24x7, rather than trying to game when they take outages to avoid penalties as is done today with RAAIM. Additionally several stakeholders asked that we publish when UCAP Assessment Hours fell in the previous year. The CAISO will accommodate this request and will publish after-the-fact when UCAP Assessment Hours occurred during the previous Peak and Off Peak Months as part of its annual UCAP process.

Proposed UCAP Determination Process

Once the CAISO has identified which hours are UCAP Assessment Hours it will use the following process to determine a resource's UCAP value using the seasonal availability approach. The CAISO will calculate an hourly unavailability factor using forced and urgent outages and derates for each hour studied, divided by the resource's maximum capability for each of the 20% of tightest supply cushion hours per summer season, May-September (on-peak), and the 20% of tightest supply cushion hours per winter season, October-April (off-peak), for the past three years. To determine each resource's Hourly Unavailability Factor (HAF) for each of the tightest supply cushion hours per season the CAISO proposes the following approach:

$$\textbf{Hourly Unavailability Factor} = \frac{\textbf{Derates} + \textbf{Forced} \,\&\, \textbf{Urgent Outage Impacts}}{\textbf{NQC}}$$

The CAISO will utilize the average of the Hourly Unavailability Factor (HUF) for each season for each of the past three years to create a Seasonal Average Availability Factor (SAAF) for each resource:

$$\textbf{Seasonal Average Availability Factor} = \mathbf{1} - \frac{\sum \textbf{Hourly Unavailability Factors}}{\textbf{Number of Observed Hours}}$$

The CAISO also proposes incorporating a weighting method that places more weight on the most recent year's performance and less weight on more historic periods in determining a resource's UCAP values. The CAISO proposes to place the following percentage weights on the availability factor calculation by year from most recent to most historic: 45-35-20%. In other words, the following percentage weights will be applied to the seasonal availability factors; 45% weight for the most recent year's seasonal availability factor, 35% weight on the second year, and 20% on the third year most historical seasonal availability factor. The CAISO will then apply this proposed weighting approach to each of the three previous annual periods (for each on-peak and off-peak season) to create Weighted Seasonal Average Availability Factors (WSAAF) as follows:

$$\begin{aligned}&\textbf{Weighted Seasonal Average Availability Factor}\\ &\qquad = \textbf{Annual Weighting} * \textbf{Seasonal Average Availability Factor}\end{aligned}$$

Once the Weighted Seasonal Average Availability Factors are established for each season of each of prior three years the CAISO will sum the factors and apply them to each resource's NQC to determine the resource's seasonal UCAP ratings as follows:

$$\textbf{On Peak UCAP} = \sum \textbf{Weighted Seasonal Average Availability Factors}^{\textbf{Summer}} * \textbf{NQC}$$

$$\textbf{Off Peak UCAP} = \sum \textbf{Weighted Seasonal Average Availability Factors}^{\textbf{Winter}} * \textbf{NQC}$$

The following tables provide examples based on the forced outage rates of three thermal resources currently on the CAISO system to illustrate the proposed UCAP determination process. For brevity and simplicity, the initial steps of determining the Hourly Availability Factors and Seasonal Availability Factors have been omitted, but those steps will be calculated as described above and incorporated prior to the following steps in the process. To preserve anonymity of the resource, the NQC values have been modified and the resource's outage MW values have also been changed in proportion.

Table 5: Determining UCAP value of Thermal Resource A

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.911	20%	0.182
2	0.835	35%	0.292
1	0.931	45%	0.419
		Total = 100%	0.893
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.986	20%	0.197
2	0.986	35%	0.345
1	0.987	45%	0.444
		Total = 100%	0.986

Sum of Weighted SAAFs (Summer)	Sum of Weighted SAAFs (Winter)	NQC	On-Peak UCAP	Off-Peak UCAP
0.893	0.986	250 MW	223.25 MW	246.5 MW

Thermal Resource A in the Peak Months of Year 2, this resource submit frequent “plant trouble” forced outages for a portion of its NQC value, which resulted in a Seasonal Availability Factor of 0.835. The plant seems to have fixed this underlying issue and its Seasonal Availability Factor increased to 0.931 in Year 1. The Resource’s Off-Peak Seasonal Availability factor remained consistently around 0.987.

Table 6: Determining UCAP value of Thermal Resource B

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.941	20%	0.188
2	0.990	35%	0.347
1	0.891	45%	0.401
		Total = 100%	0.936
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.972	20%	0.194
2	0.982	35%	0.344
1	0.962	45%	0.433
		Total = 100%	0.971

Sum of Weighted SAAFs (Summer)	Sum of Weighted SAAFs (Winter)	NQC	On-Peak UCAP	Off-Peak UCAP
0.936	0.971	100 MW	93.6 MW	97.1 MW

Thermal Resource B began submitting frequent “Ambient not due to Temperature” outages for a small portion of their NQC value on a regular basis, starting in Peak Months of Year 1, along with a few other outages caused by plant trouble that reduced the resource’s Peak Month SAAF from 0.990 to 0.891. A similar pattern emerged in Off-Peak Months, but the frequency in which they submitted “Ambient not due to Temperature” outages was less in Year 1, so the resource’s Off Peak SAAF only decreased from 0.982 to 0.962.

Table 7: Determining UCAP value of Thermal Resource C

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.947	20%	0.189
2	0.929	35%	0.325
1	0.964	45%	0.434
		Total = 100%	0.948
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.818	20%	0.164
2	0.958	35%	0.335
1	0.678	45%	0.305
		Total = 100%	0.804

Sum of Weighted SAAFs (Summer)	Sum of Weighted SAAFs (Winter)	NQC	On-Peak UCAP	Off-Peak UCAP
0.948	0.804	50 MW	47.42 MW	40.20 MW

Thermal Resource C also submitted semi-regular “Ambient not due to Temperature” outages which affected both their Peak and Off Peak SAAFs. However, in the Off Peak Months in Year 1, this resource experience frequent and sustained “Plant Trouble” forced outages for its full NQC value. This had a large impact on the resource’s Off Peak SAAF, reducing it to 0.678. One advantage of the proposed weighting methodology and only looking at three years is that if the resource invested in the necessary repairs to address the underlying issue, the impact of this bad Off Peak SAAF would lessen over time and eventually roll off, allowing the resource to increase its capacity value over time.

As a whole, what these three examples point to is that this UCAP counting methodology is driven more by the frequency and persistence of outages rather than a “luck” factor. In fact, the impact of a single day outage, which included the average five UCAP Assessment Hours, would only reduce a resource’s UCAP value by 0.3% in Year 1, 0.24% in Year 2, and 0.14% in Year 3, if we assume 100% availability in all other hours.

Several stakeholders requested that we establish a dead band around which we would not begin to derate a resources NQC value. LS Power, SEIA, and EDF-Renewables suggested that we not derate a resource’s NQC value unless the resource’s WSAAF was .98 or below. The additional of a dead band would add significant complexity in terms of establishing the correct UCAP requirements. If we were to establish this dead band, we would likely have to increase the system RA requirements to account for this 2% decrease in capacity, which could be as high as 1000 MWs in peak months. This increased capacity procurement requirement would then have to be allocated to LSEs. CAISO is continuing to vet this suggestion internally. The CAISO would like additional stakeholder feedback on whether to establish a dead band around a resource’s UCAP value given the associated benefits and burdens of this option.

In the next section, we explain modification to the base UCAP calculation methodology for new resources, energy storage technologies, and hydro resources to better capture their true availability and prevent double counting.

UCAP methodology for new and non-conventional resource types

New resources

The CAISO is considering two approaches for calculating UCAP for new resources without three full years of operating history. Option 1 is a class average approach. Class averages would be based on outage rates for similarly designed resources of the same technology type. The class-average will be based on availability factors observed during the tightest 20% supply cushion hours each season (summer and winter) per year for the previous three years. As new resources begin to build an operational history, the CAISO will blend their actual performance data with class average data, beginning with the class average and maintaining constant weights over time, as follows:

- Year 0 (i.e. before actual operational data is available): 45% class average, 35% class average, 20% class average
- Year 1: 45% year 0 performance, 35% class average 20% class average
- Year 2: 45% year 1 performance, 35% year 0 performance, 20% class average
- Year 3: 45% year 2 performance, 35% year 1 performance, 20% year 0 performance

In this approach, resources begin with the class average, which may be lower or higher than the resources' actual performance. Weights are constant under option 1 and puts lower weight on earlier years than option 2, allowing resources to "work out any bugs" that occur in early years of operation.

Under option 2, resources will begin with their NQC the first year, and places heavy emphasis on actual performance in the initial years. Under this approach, resources will start with a higher capacity value, but actual performance will have a significant impact early on. The CAISO included this option based on stakeholder feedback from LS Power expressing concern with using the class average for new battery storage resources, given the relatively small number of battery storage currently participating in the market, which may not reflect the operational characteristics of future projects. Weights for option 2 are:

- Year 0 (i.e. before actual operational data is available): NQC
- Year 1: 70% year 0 performance, 30% NQC
- Year 2: 55% year 1 performance, 35% year 0 performance, 10% NQC
- Year 3: 45% year 2 performance, 35% year 1 performance, 20% year 0 performance

In comments to the working group meeting on June 10th, Stakeholders provided an even split between the two options. Option 1 was supported by CalCCA, NRG, and the Public Advocates Office, whereas Option 2 was supported by CESA, EDF- Renewables, and LS Power. CAISO requests additional stakeholder feedback on these two options for the UCAP calculation and weighting for new resources.

Storage

In addition to outages, optional parameters available to storage resources will reduce RA amount. For example, in the Energy Storage and Distributed Energy Resources Phase 4 initiative, the CAISO proposed and end-of-hour state of charge (EOH SOC) parameter, an optional real-time market biddable parameter that allows storage resources to achieve a desired state of charge by the end of an hour. It also outlined a market enhancement to preserve minimum SOCs in order to respect self-schedules in future hours[23]. Resources can also elect SOCs in the master file which may limit resource availability below RA value. The UCAP calculation should consider these SOC constraints, in addition to forced outage rates, if the SOC is set such that the resource's full RA amount is not available.

The CAISO developed the proposal for storage UCAP counting with the following objectives:

- UCAP calculation should not double count if there is overlap between unavailability caused by both forced outage and SOC constraint;
- UCAP calculation should consider how SOC constraint affects ability to be available for full RA value for the minimum duration required for RA resources, currently 4 hours, and;
- UCAP calculation should consider outages on both the charge and discharge portion of the resource.

The CAISO proposes a formulation for resource availability for any specific hour as the minimum of: 1) the absolute value of the effective minimum that the storage resource could be dispatched to (i.e. not on outage on the charge portion), 2) the effective maximum the resource could be dispatched to (i.e. not on outage on the discharge portion), and 3) the total amount of energy that the resource can store (i.e. energy not subject to min/max constraints during that hour) divided by the resource adequacy continuous deliverability duration (currently four hours). After this value is calculated it can be used to determine the resource's hourly unavailability factor defined above.

$$\boldsymbol{Availabiltiy} = \mathbf{min}(\boldsymbol{ABS}(\boldsymbol{Effective\ Min}), \boldsymbol{Effective\ Max},\ \frac{\boldsymbol{Effective\ Energy}}{\mathbf{4}})$$

The following examples demonstrate the impact of both forced outages and state of charge on resource availability. Assume a +/- 25 MW storage resource with 100 MWh of energy storage capability.

Outages and State of Charge Examples:

Hour 1: The resource is not on outage (+/- 25 MW) in the real-time market, and there is no constraint on the state of charge for this hour

- Total 4-hour deliverable energy in hour 1 (effective availability): 25 MW

Hour 2: The resource is on outage for 5 MW (+/- 20 MW) in the real-time market, and there is no constraint on the state of charge for this hour

- Total 4-hour deliverable energy in hour 2 (effective availability): 20 MW

[23] Energy Storage and Distributed Energy Resources Stakeholder Initiative Webpage: http://www.caiso.com/StakeholderProcesses/Energy-storage-and-distributed-energy-resources

Hour 3: The resource is not on outage (+/- 25 MW) in the real-time market, but imposes a minimum end of hour SOC of 25 MWh

- Total 4-hour deliverable energy in hour 3 (effective availability): 18.75 MW = (100 MWh – 25 MWh) / 4 hours

Hour 4: The resource is on outage for 10 MW (+/- 15 MW) in the real-time market, and imposes a minimum end of hour SOC of 25 MWh and a maximum state of charge of 75 MWh

- Total 4-hour deliverable energy in hour 1 (effective availability): 12.5 MW = (75 MWh – 25 MWh) / 4 hours; note that this value is selected because it is less than the 15 MW that is bid into the market

When considering forced outages for storage, the UCAP calculation should consider outages on both the charge and discharge portion of the resource to ensure the resource can be charged and available to the grid when needed. The next examples demonstrate how the same resource's availability would be impacted by outages on either the charge, discharge portion, or both. Assume no constraints on the state of charge in these examples.

Outages on Charge and Discharge Examples

Hour 5: Bid range from -20 MW to 25 MW (5 MW outage on the charge portion)

- Resource's effective availability is 20 MW for this hour

Hour 6: Bid range from -25 MW to 18 MW (7 MW outage on the discharge potion)

- Resource's effective availability is 18 MW for this hour

Hour 7: Bid Range from -50 MW to 25 MW

- Resource's effective availability is 25 MW for this hour

Hour 8: Bids Range from -50 MW to 50 MW

- Resource's effective availability is still only 25 MW for this hour because that is the most that could be delivered persistently for 4 hours, given 100 MWh of energy storage capacity, and equal to the resource's NQC

Table 8 summarizes each of the above examples and its impact on the hourly unavailability factor for the UCAP calculation:

Table 8: Calculating Hourly Unavailability Factor for storage resources

Example (Hour)	Effective Min (-MW)	Effective Max (MW)	Effective energy available (MWh)	Effective availability (MW)	Unavailability (MW) (NQC – Effective Availability)	Hourly Unavailability Factor (MW) (Unavailability /NQC)
1	25	25	100 / 4 = 25	25	0	0
2	20	20	100 / 4 = 25	20	5	0.2
3	25	25	75 / 4 = 18.75	18.75	6.25	0.25
4	15	15	50 / 4 = 12.5	12.5	12.5	0.5
5	20	25	100 / 4 = 25	20	5	0.2
6	25	18	100 / 4 = 25	18	7	0.28
7	50	25	100 / 4 = 25	25	0	0
8	50	50	100 / 4 = 25	25	0	0

Hydro

Hydro resource output depends heavily on water availability, which can vary from year to year. To capture this variability, CAISO proposes an alternative to the standard UCAP calculation, which would use a historical-year weighted average assessment of resource availability during the 20% tightest supply condition hours to capture the variability of hydro output. Historical bid in capacity would be used to calculate a 50 percent exceedance and a 10 percent exceedance value. The CAISO proposes to weight the 50 percent value by 80 percent and the 10 percent value by 20 percent to determine the UCAP value.

The CAISO believes this alternative methodology is generally consistent with the hydro counting methodology outlined in the CPUC's proposed decision in track 2 of the Resource Adequacy

Proceeding.[24] Under that proposal, historical bid in capability during the availability assessment hours is used to establish the historical weighted average. In this counting methodology, mechanical outages are removed from the QC calculation, such that only outages due to water unavailability are included. Those mechanical outages are then subject to RAAIM.

Under the CAISO's UCAP proposal, the CAISO would evaluate resource availability during the tightest 20% supply cushion hours for the on and off peak seasons, considering outages due to both water availability and mechanical outages for the previous 10 years.[25] Mechanical forced outages must also be considered in addition to water availability under the UCAP construct to remain consistent with incorporating all forced outages upfront in the UCAP calculation once RAAIM and substitution are no longer be in place.

In this simplified example, assume a Hydro Resource with a Pmax of 100 MW with the following unavailability in MWs during the top 20% tightest supply cushion hours (for this example, assume these hours align with the current availability assessment hours).

Table 9: Example resource unavailability

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	…
Fuel Unavailability	0	0	25	10	5	15	22	5	0	0	
Mechanical Outage**	0	25	25	0	0	0	10	0	0	0	
Total Hourly Unavailability	0	25	50	10	5	15	32	5	0	0	

** Under the existing methodology in place at the CPUC, mechanical outages are not factored into the QC, but are subject to RAAIM. For simplicity, assume no overlap of fuel and mechanical outage capacity.

Under the existing methodology in place at the CPUC, the resource's QC would be calculated as follows:

Table 10: Existing hydro counting methodology

	Fuel Unav.	Avail (w/water)	****Uses 10 years of availability**
HE1	0	100	
HE2	0	100	
HE9	0	100	

[24] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M338/K277/338277501.PDF
[25] If historical bidding data is not available for 10 years, the ISO will consider as much outage data that is available.

HE10	0	100	
HE5	5	95	Median
HE8	5	95	Median
HE4	10	90	
HE6	15	85	
HE7	22	78	
HE3	25	75	10th Percentile
…			

The resulting NQC = (.8*Median+.2*10th percentile) = 91 MW and the resource is subject to RAAIM for mechanical outages.

Under the CAISO's proposed UCAP methodology, the resource's UCAP would be calculated as follows:

Table 11: Proposed Hydro UCAP methodology

	Fuel Unavailability	Mechanical Outage	Tot. Unavailability	Availability	****Uses 10 years of availability**
HE1	0	0	0	100	
HE9	0	0	0	100	
HE10	0	0	0	100	
HE5	5	0	5	95	
HE8	5	0	5	95	Median
HE4	10	0	10	90	Median
HE6	15	0	15	85	
HE2	0	25	25	75	
HE7	22	10	32	68	
HE3	25	25	50	50	10th Percentile
…					

The resulting UCAP = (.8*Median+.2*10th percentile) = 84 MW.

Because the hydro counting proposal requires more years of data than the UCAP calculation for thermals and storage, the CAISO is considering how to transition from the existing CPUC counting methodology that uses historical availability during the RAAIM hours, to the using the historical availability during the tightest 20% supply cushion hours. The CAISO plans to calculate the tightest supply cushion hours beginning three years before the implementation of this policy, currently 2019. The CAISO proposes to use the historical availability during the RAAIM hours for years prior to 2019 and the historical availability during the 20% tightest supply cushion hours in years 2019 and beyond. The CAISO is seeking stakeholder feedback on this approach for hydro resources and whether this is necessary or preferred to the standard UCAP calculation to reflect hydro availability.

ELCC counting

The CAISO recognizes that the proposed availability factor approach to determine UCAP values may not be the best approach for every resource type, specifically, Solar, Wind, and Demand Response, which require alternative approaches.

The CAISO proposes to use an ELCC value for wind and solar to set UCAP values. Other resource types that may not work well under Availability Factors are those that have inherent use limitations such as some DR and QF resources. The CAISO considered these different resource technologies and explains the current proposal for setting UCAP values for these resource types below.

Wind and Solar

The CAISO will rely on an ELCC methodology when applicable. Currently, the CPUC only applies this methodology to wind and solar resources, but could expand it to cover other variable energy resources such as weather sensitive or variable output DR. The reason for the CAISO's reliance on the ELCC calculation for wind and solar is two-fold. First, other ISOs equate wind and solar UCAP values with a statistical assessment of resources' output. Second, the ELCC already takes into account the probability of forced outages for wind and solar resources.[26] Therefore, the CAISO understands these technologies already have their QCs reduced for expected forced outages and derates.

The CPUC's ELCC calculation has two challenges as applied for this purpose. First, the CPUC calculates the average ELCC for the wind and solar fleet. This means that some resources will perform better than average, while others will perform worse. If all wind and solar resources are shown for RA, then there is no problem. However, if only a subset of solar and/or wind resources are shown as RA, then the average ELCC value of the RA wind and solar fleet may differ from the average ELCC value of the entire fleet.

A second but related issue is the CPUC calculates a diversity benefit that relies on the portfolios of wind and solar resources. If the showings have a different ratio of wind and solar resources, then the diversity benefit may not be reflected in the RA fleet. Either of these issues can result in over or under-procurement depending on what resources are shown as RA.

[26] Forced outages are accounted for by using actual production data to inform the wind and solar production profiles in the ELCC modeling.

Demand Response

The CAISO notes that some DR resources also need an alternative approach for determining their UCAP values. This is because majority of DR resources exhibit variability and are availability-limited. This approach may not work well with the availability factor approach that assesses availability based upon tightest supply condition hours that can occur during any hour of the day, and may include hours when DR programs are not available. This approach would likely impact DR resources' UCAP values since these resources are generally only available during a subset of hours. Because of their limited and variable availability on a daily and annual basis, the CAISO believes that DR resources are best evaluated under an ELCC approach similar to wind and solar resources that have limited or variable output.

Through the Energy Storage and Distributed Energy Resources initiative, the CAISO is studying application of an ELCC methodology to DR resources.[27] The CAISO will use this methodology to inform local regulatory authorities of a QC counting methodology that incorporates the variable and availability-limited nature of certain DR resources into its QC value. Similar to the ELCC methodology for wind and solar, an ELCC methodology for DR would consider resource availability and DR's ability to serve system reliability when determining the capacity value of DR. If LRAs adopt an ELCC methodology for DR resources, the CAISO could rely on the ELCC methodology to establish UCAP values for DR resources as it proposes to do for wind and solar resources. If LRAs do not adopt an ELCC methodology for DR resources, the CAISO proposes to use a historic performance based approach described below.

For DR and QF resources, their availability is often variable or limited to certain periods dictated by program hours or end-use customer needs. The CAISO believes these resources should be assessed in a different manner than other resource types to establish their UCAP values. If the LRAs do not adopt an ELCC based QC methodology for these variable and availability-limited resources, the CAISO will apply the following UCAP determination approach. For DR and QF resources, the CAISO will evaluate these resources' performance relative to their dispatch instructions for periods when they received market awards or test events.

For DR providers, the CAISO proposes applying this approach at an SC-level, rather than an individual resource level to mitigate the potential for gaming or manipulation by simply creating new DR resource IDs. This SC-level approach is intended to block the ability for poorly performing DR providers to receive class-average UCAP values simply by changing or creating a new resource IDs that have no historical data.

The CAISO will track these resources historical performance over the prior 3 years and compare their market dispatches to their actual performance during those periods to establish the availability that will be applied to their UCAP value.

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[27] ESDER 4 Stakeholder Initiative Webpage: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx

Transition from NQC to UCAP

The CAISO proposes a clean transition from the current NQC to the new UCAP-based approach rather than a phased in approach. The CAISO proposes that the 2022 RA year binding RA requirements would still be in terms of today's NQC values, but we would "shadow" test both UCAP RA requirements and showings. The 2023 RA year would transition to binding RA requirements and showings in terms of UCAP. CalCCA expressed support for this transition timeline. SDG&E did not support starting UCAP in the 2023 RA year because this is the same year that the Central Procurement Entity was instructed to begin by the CPUC, and this could add additional complexity to the transition. SMUD also did not support transitioning in 2023 RA year because many LSEs have already contracted through 2023, and suggest we transition to UCAP in 2024 to remain more consistent with CPUC rules. The CAISO seeks additional feedback on timing of the transition from NQC to UCAP.

Given CAISO's reluctance to grandfather existing contracts, several stakeholders asked the CAISO to take steps to ease this transition for existing contracts. For instance, SCE has advocated that we keep RA requirements in terms of NQC, and derate NQC values for forced outage rates rather than creating a new term. In the Working Group Meeting on June 10, the CAISO presented two options for integrating unforced capacity outages into the RA program, and received mixed stakeholder feedback.

Option 1 would create a two-step de-rate process to a resources QC. The first step in this process would be to conduct a resource deliverability assessment to adjust QC for deliverability and create a new term Deliverable QC (DQC). The Deliverable QC would take the place of the NQC term used today. The second step is to apply the Weighted Seasonal Average Availability Factors to the resource's DQC, which would result in the NQC for the resource. The new definition of NQC would represent the UCAP value of the resource. Under this option, a resource's must offer obligation would be set at its DQC. The advantages of this option is that it would continue to express capacity values in terms of NQC and address stakeholder concerns around existing contracts. The disadvantage of this option are that it could create confusion by changing the meaning of an existing term. CalCCA, CESA, EDF-Renewables, and SCE submitted comments in support of option 1.

Option 2 would retain the existing definition of NQC and create a new term (UCAP) to represent a resource's capacity value. This approach would apply the Weighted Seasonal Average Availability Factors to the resource's NQC value, and result in the new UCAP value. This approach would not introduce the potential confusion resulting from a dual meaning of the term NQC over time. Clarifications of existing RA contracts would be jointly required, and would not favor one side over the other. This option would not address the contracting concerns brought up by stakeholders. Calpine, CDWR, NRG, Powerex, Six Cities, SDG&E, and Wellhead submitted comments in support of option 2. The CAISO also favors option 2. However, given the split among stakeholders, the CAISO seeks additional feedback on which option to pursue, as well as any other potential pros and cons associated with each option.

Coordination of Proposed UCAP Concept with CPUC RA Program

The CAISO received stakeholder feedback that it must closely consider how its proposed UCAP concept will be coordinated with the current CPUC RA program. Certain parties expressed concern that the CAISO proposal could create conflicting RA requirements, or otherwise undermine the System RA Planning Reserve Margin (PRM) established by LRAs. CAISO appreciates these concerns and will work with LRAs to align RA programs with the current proposal, including the CAISO submitting its proposed counting rules in the upcoming CPUC RA proceeding.

The CAISO's proposal provides improved transparency over resource forced outage rates, which will help improve procurement of the most dependable and reliable resources and better inform retirement decisions. Existing installed capacity measures reflect an expected fleet average outage rate factored into the PRM, which can result in inefficient resource procurement on the low end of the forced outage distribution and more overall procurement than might be seen using UCAP values. The CAISO seeks stakeholder input to identify any additional CPUC/LRA RA program issues or UCAP related concepts that should be included for consideration and coordination.

Removing Forced Outage Replacement and RAAIM application to forced outage periods

CAISO's analysis in Appendix 8.3 shows that RAAIM does not effectively ensure adequate capacity will be provided to the CAISO and, therefore, it is reasonable to eliminate RAAIM once an alternative solution is in place.

The CAISO believes a superior approach is to establish incentives to conduct resource maintenance to avoid outages and to procure capacity that is more reliable in the first instance. UCAP provides the proper incentives, while still allowing LSEs to procure the most cost effective capacity needed to meet their procurement obligations. The relationship between MOOs, RA substitution rules, and RAAIM creates a complex system of processes that differ vastly from other ISOs/RTOs. In light of the data in Appendix 8.3 and CAISO's UCAP proposal, it is possible and desirable to eliminate these complex relationships for a process that appropriately relies on the upfront and transparent accounting of resource availability and reliability.

4.1.3. System RA Showings and Sufficiency Testing

Stakeholder feedback

As a general matter, most stakeholders support the CAISO developing a portfolio assessment for only RA resources using the stochastic model similar to the production simulation model used in the CAISO's summer assessment. The CAISO provides additional detail on this model, below.

Stakeholders also continue to request additional information about establishing up-front rules and/or guidance to minimize the risk of backstop and backstop cost allocations. To address these concerns, the CAISO is doing two things. First, the CAISO is coordinating with the CPUC and will work with other LRAs such that LRAs are able to set up-front requirements for their jurisdictional LSEs. Second, as noted above in section 4.1.1, is working to provide preliminary results from a test run using June 2020 RA showings to help further inform market participants. The CAISO will issue a supplement to this proposal upon completion of this assessment. This section remains unchanged pending the results of this assessment.

Overview

The CAISO will conduct two sufficiency tests for system capacity: an individual deficiency test and a portfolio deficiency test. These tests are designed to ensure there is both adequate UCAP to maintain reliability for peak load and that the portfolio of resources, when combined, work together to provide reliable operations during all hours at the system level. The CAISO will also conduct tests for flexible and local capacity needs, described in Section 4.4.

Individual Deficiency Assessments

The CAISO will assess LSE RA showings and resource supply plans to ensure there is sufficient UCAP shown to meet the identified UCAP need described above. Because the CAISO will be assessing system capacity showings based on UCAP values, the CAISO proposes that LSEs and resource SCs need only submit and show resources' UCAP values. Once shown, the CAISO will consider each resource's UCAP value to conduct its UCAP assessment.

Additionally, LSEs will not be permitted to procure only the "good part" of a resource (*i.e.*, LSEs cannot simply procure only the unforced capacity portion of a resource, and any amount shown for RA will be assessed considering the resource's forced outage rate). For example, an LSE could not claim to buy 90 MW of both NQC and UCAP from a 100 MW resource with a 10 percent forced outage rate. In comments to the straw proposal – part 2, several parties requested CAISO allow resources to sell and show only the UCAP value of the resource. There are two reasons CAISO cannot allow this. First, the UCAP accounting method relies on the probability that some resources will be out at various times. Allowing some resources to do so would likely require CAISO to maintain the same complicated substitution rules it is seeking to eliminate to maintain the desired level of reliability. Second, the CAISO's review of best practices in other ISO's shows such practices are not permitted.

Partial RA resources (shown for RA for only a portion of its capacity) will receive a proportional UCAP value reflecting the proportion shown for RA purposes (*i.e.*, a 100 MW resource with a 10 percent forced outage rate shown for 50 MW of NQC will be assessed as being shown for 45 MW of UCAP RA).

LSEs that fail to meet the UCAP requirement will be notified of the deficiency and provided an opportunity to cure. LSEs that fail to cure may be subject to backstop procurement cost allocation. Specific backstop procurement authority for this deficiency and cost allocation are discussed in greater detail in Section 4.4.

Individual RA Showing Incentive

The CAISO also proposes to develop an individual LSE RA showing incentive. The CAISO proposes to develop a new tool called the UCAP deficiency tool, which is intended to discourage LSEs from failing to show RA at least equal to their UCAP requirement and incentivize LSEs to show above their UCAP obligations. The concept of the UCAP deficiency tool is to apply a penalty to LSEs that show less than (below) their UCAP requirement, and distribute those collected penalties to LSEs showing over (above) their UCAP requirements. This proposed tool and incentive is described in Section 4.4. Examples and further discussion of this proposed concept are also provided below.

Portfolio Assessment

The CAISO will conduct a portfolio deficiency test of the resources shown for RA to determine if the portfolio is adequate to serve load under various load and net load conditions during all hours of the day. The portfolio deficiency test will use only the shown RA fleet in a production simulation to determine if the CAISO is able to serve forecasted gross and net-load peaks, and maintain adequate reserves and load following capability. The need for this assessment is similar in concept to the collective deficiency test CAISO conducts for local RA. However, the CAISO will only conduct this assessment for monthly RA showings because they are the only showings where LSEs must meet 100 percent of the system, local, and flexible RA capacity requirements. The increased number of energy and availability-limited resources on the system and the reliance on these resources to meet RA needs means that some resource mixes provided to meet RA requirements may not ensure reliable operation of the grid during all hours of the day across the entire month. Similar to the local assessments, the CAISO is looking to maintain a consistent definition for capacity to facilitate transacting a homogeneous product. However, the CAISO must assess how the shown RA fleet works collectively to meet system needs.

The objective of a portfolio analysis is to assess if the CAISO can serve load with the shown RA fleet. Because year ahead system RA showing requirements are currently only 90 percent for the five summer months for CPUC jurisdictional entities, the CAISO can only reasonably conduct this assessment using monthly RA showings.

The CAISO has considered a variety of deterministic, stochastic, and hybrid modelling approaches for this portfolio analysis. Based on stakeholder feedback and additional CAISO assessments, the CAISO has determined that a stochastic approach offers the greatest opportunity to assess the widest array of load, wind, and solar profiles as well as various outage profiles for other resource types. Additionally, the CAISO sought to leverage its existing production simulation expertise and modeling by relying on tools that are already available. This provides at least two benefits. First, using an existing production simulation model will help the CAISO expedite testing and implementation. Second, the CAISO can utilize an accepted and vetted model that has been relied on for other CAISO published studies.

The CAISO proposes to use the production simulation tool that it currently uses for the Summer Loads and Resources Assessment (Summer Assessment) study.[28] The CAISO has used its production simulation tool to conduct this study since 2016, updating the model annually to

[28] The annual study process is typically completed in May of each year. The most current study is the 2019 assessment, available at http://www.caiso.com/Documents/Briefing-2019-SummerLoads-Resources-Assessment-Report-May2019.pdf

create a robust tool for CAISO to convey potential risks for the upcoming summer needs. More specifically,

> The 2019 Summer Loads and Resources Assessment ("Assessment") provides an assessment of the upcoming summer supply and demand outlook for the California Independent System Operator (CAISO) balancing authority area. The CAISO works with state agencies, generation and transmission owners, load serving entities, and other balancing authorities to formulate the summer forecast and identify any issues regarding upcoming operating conditions. The Assessment considers the supply and demand conditions across the entire CAISO balancing authority area (representing about 80 percent of California).[29]

Although the Summer Assessment has been developed for a slightly different purpose, much of the core modelling functions are identical to what the CAISO needs for the proposed portfolio analysis. For example, the model is a detailed representation of loads and resources characteristics across the CAISO. It can also model resources across the WECC, allowing the CAISO imports into the CAISO. The model commits resources based on load, unit specific forced outage rates, ramp rates, start times, and minimum down times to meet CAISO needs, including operating reserves, regulation, and load following. Load following requirements are necessary because the analysis is run on hourly blocks. The model can run both stochastically and deterministically, allowing the CAISO to develop robust statistical results while still testing various sensitivities.

The CAISO notes that the model setup will be different from that of the Summer Assessment to align its functions with the objective of an RA portfolio assessment. The primary difference will be to allow only RA resources to be scheduled by the model. The Summer Assessment assumes that all resources are available to the CAISO to meet peak summer loads. However, the portfolio assessment model will only model the shown RA resources to assess how well the RA fleet meets a given reliability standard. Energy provided in the CAISO's day-ahead or real-time markets from non-RA resources represents economic energy substitutes, which will not be considered in the portfolio assessment to determine if the RA fleet is adequate. Additionally, the CAISO will coordinate with the CPUC and CEC to develop a common set of hourly load profiles so that the CAISO and the CPUC are using consistent distribution of load profiles for their respective modeling purposes.

If the portfolio is adequate, the CAISO will take no additional actions. If the RA portfolio fails the portfolio assessment, the CAISO will declare a collective deficiency, provide a cure period, and if the deficiency remains, conduct backstop procurement using the CPM competitive solicitation process to find the least cost solutions to resolve any uncured deficiency. The CAISO provides the specific details regarding CPM designations and cost allocation in Section 4.4.

A stochastic monthly assessment of the RA fleet to support additional backstop procurement authority creates unique challenges that do not exist under the simple accounting tools currently used for RA showings. The two primary challenges are (1) establishing the defined reliability

[29] http://www.caiso.com/Documents/Briefing-2019-SummerLoads-Resources-Assessment-Report-May2019.pdf at p. 1.

criteria that triggers the need for backstop procurement, and (2) establishing the quantity of capacity needed to cure the portfolio deficiency. As part of this stakeholder initiative, the CAISO will propose solutions to both of these challenges. However, at this time, the CAISO only provides additional details regarding each challenge and will propose specific solutions in subsequent proposals within this stakeholder process.

Stochastic capacity analyses have been conducted in California for several years, starting with the CPUC's Long-Term Procurement Planning process. These analyses have evolved, and variations of these types of studies are used in the CPUC's Integrated Resource Planning proceeding and the RA proceeding for determining ELCC values for wind and solar. Despite all of the work that has been in these proceedings, there is still a great deal of debate about the ultimate reliability standard that must be met. Some of the debate centers on the difference between studying a full year, which has been done historically in most LOLE studies, versus a single month, which is done for California's RA program. Another area of debate includes what constitutes a loss-of-load event. For example, the original loss-of-load studies did not account for ancillary service requirements. Current studies include ancillary services, but there is a debate about whether a loss-of-load event is defined by utilizing any of those ancillary services or only by merely dropping below three percent reserves – when the CAISO must initiate firm load shedding. Alternatively, the answer to what constitutes a loss-of-load event may also include how often the CAISO would be expected to rely on its reserves. For example, how often is it acceptable for the CAISO to rely on reserves and dip below 6 percent reserves? Is it acceptable during one percent of hours, 10 percent, 15 percent or more? As noted above, the CAISO will offer a solution in a subsequent iteration.

In addition to developing criteria for when additional capacity is needed, the CAISO must also develop a methodology to determine how much capacity is needed. Therefore, if the CAISO identifies a portfolio deficiency, the CAISO must establish a means for determining the amount of additional capacity needed either through a capacity cure period or through CAISO backstop procurement

The CAISO considered additional assessments of individual RA showings, however, it is not feasible to adequately develop individual LSE load profiles and determine how a specific LSE's RA portfolio contributed to the collective deficiency and, therefore, is subject to LSE specific cost allocation. However, the CAISO supports, and is committed to, working with the LRAs to establish up-front procurement requirements, similar to the CPUC's maximum cumulative capacity (MCC) buckets to help ensure collective procurement of a resource portfolio with the best possibility of passing the portfolio assessment.

4.1.4. Must Offer Obligation and Bid Insertion Modifications

The RA program is designed to ensure the CAISO has sufficient capacity available to serve load reliably all hours of the year. Any resource providing RA capacity to the CAISO is obligated to offer that capacity into the CAISO market. This ensures the market has sufficient bids available to dispatch resources to serve system load reliably. RA resources will continue to have a must offer obligation under RA Enhancements. Currently, the CAISO tariff contains provisions regarding must offer obligations, bidding, and bid insertion rules. The CAISO proposes the following must offer obligation and bid insertion modifications in this initiative:

- Must offer obligations must be set at the amount of NQC shown for RA, not the amount of UCAP shown;
- Resources have a 24 by 7 must offer obligation into the day-ahead market unless exempt, and;
- Resources will receive bid insertion, unless exempt.

Must offer obligations must align with NQC values

The CAISO proposes a resource's must offer obligation be consistent with the resource's shown capacity scaled up for the forced outage rate adjustment. This means that the must offer obligation will be for the equivalent installed capacity, up to the resource's NQC value. For simplicity, the CAISO will refer to this quantity as shown NQC. This is consistent with the practice in other ISO/RTOs.[30] More specifically, if a 100 MW resource with a 20 percent forced outage rate is shown for 80 MW of UCAP, then it has shown its full 100 MW of NQC. It must then bid 100 MW of capacity into CAISO's markets when the resource is not on outage.[31] This bidding rule is required to ensure sufficient capacity is available to the system at all times by accounting for the fact that some resources will be on forced outage. Absent this requirement, units must be available 100 percent of the time to their UCAP values or provide substitute capacity, otherwise the CAISO would be short of available RA capacity. Assuming resources are available 100% of the time is an unreasonable expectation and requiring replacement capacity defeats the goal of simplifying RA rules.

Alternatively, and as proposed here, setting the must offer obligation at the shown NQC value allows CAISO to eliminate forced outage substitution and its complexities. By establishing a UCAP-based RA construct with an associated must offer obligation at the NQC value, the RA fleet effectively provides its substitute capacity upfront, eliminating the need for complex resource substitution rules. For this reason, CAISO proposes to eliminate the existing RA forced outage substitution rules in favor of UCAP-based resource RA counting and NQC-based resource bidding. This concept is addressed in greater detail in Section 4.1.2, above.

Resource Adequacy resources will have a day-ahead must offer obligation

[30] See "A case study in capacity market design and considerations for Alberta" at p. 22: http://www.assembly.ab.ca/lao/library/egovdocs/2017/ca7/aeso/226509.pdf. "In all the reviewed markets except California and ISO-NE, the capacity of these facilities is procured and settled as UCAP. In California and ISO-NE, the capacity obligation is denominated as installed capacity (ICAP). Notwithstanding that, in most markets, capacity is procured and settled as UCAP, the resulting performance obligation on conventional controllable generation is to offer all of the ICAP except on recognized outages."

[31] If a resource only shows a portion of its NQC as RA, the must offer obligation is set at the portion of the NQC that is shown for RA, not the full amount.

The CAISO is proposing several new capacity products in separate initiatives called reliability capacity, imbalance reserves, and corrective capacity.[32] Based on these proposals, the CAISO has determined a day-ahead must offer obligation for resource adequacy resources is sufficient to commit resources and reserve capacity for use in real-time. This is because, as proposed in the Day-Ahead Market Enhancements, the CAISO will begin procuring additional resources in the day-ahead timeframe to be available in real-time to cover uncertainty between day-ahead and real-time. Resources awarded in the day-ahead, including resources awarded reliability capacity, imbalance reserves, and corrective capacity, will have a real-time must offer obligation up to their day-ahead award. As such, the CAISO proposes must offer obligations for RA resources into the day-ahead market only. All real-time MOOs will be determined in the day-ahead market. All capacity that receives a day-ahead energy or A/S award or a reliability capacity or imbalance reserve award, regardless of RA status, will have a must offer obligation into the real-time market for all hours in which they received a day-ahead award to the amount of their day-ahead award. RA capacity that does not receive a day-ahead market award has no further obligation to be available in the real-time market.

This solution is more efficient than the current 24 by 7 resource adequacy must offer obligation into both day-ahead and real-time markets. Under this proposal, the resource adequacy program will ensure suppliers offer sufficient capacity into the day-ahead market. The day-ahead market will then commit resources to meet the energy, reliability capacity, imbalance reserve, corrective capacity, and ancillary service needs for the following trade day. Resources awarded in the day-ahead, including resources with imbalance reserve or reliability capacity awards, will have a must-offer obligation into the real-time market. The CAISO will require any resource with day-ahead awards for the new capacity products to reserve capacity in the day-ahead timeframe and make that capacity available in real-time. This will ensure the CAISO can efficiently meet uncertainty needs between the day-ahead and real-time markets. The real-time must offer obligation based on awards made in the day-ahead will provide the CAISO with adequate capacity for use in real-time, while relieving capacity not committed in day-ahead of their real-time must offer obligation.

Under the Day-Ahead Market Enhancements and RA Enhancements proposals, resource adequacy resources will have a 24 by 7 must offer obligation in the day-ahead market only. Their must offer obligation will be extended into real-time if the resource is scheduled in day-ahead for energy, ancillary services, or imbalance reserves. Although RA resources would not have a real-time must-offer obligation if they are not awarded in the day-ahead, **RA resources must still be available for exceptional dispatch after the day-ahead market whether or not they receive a day-ahead award.** If a resource is not available for exceptional dispatch after the day-ahead market, the resource should submit an outage. If resources receive an exceptional dispatch, they will be required to provide that energy real-time and would not qualify for an ED CPM designation when they respond to that exceptional dispatch.

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[32] For detailed descriptions of each product see the Day-Ahead Market Enhancements and Contingency Modeling Enhancements stakeholder initiative webpages: http://www.caiso.com/StakeholderProcesses/Day-ahead-market-enhancements and http://www.caiso.com/StakeholderProcesses/Contingency-modeling-enhancements

Resources providing system and local resource adequacy will be required to bid or self-schedule for energy and bid or self-provide ancillary services. Additionally, resources providing system and local resource adequacy will be required to economically bid for reliability capacity and corrective capacity. Resources providing system and local resource adequacy only will not be required to bid for imbalance reserves.

If a resource self-schedules its entire resource adequacy obligation into the day-ahead market for energy or ancillary services, economic bids will not be required for any of the other products. If a resource economically bids its entire resource adequacy obligation for energy and ancillary services, the resource must economically bid for reliability capacity and corrective capacity.

If a portion of the resource is self-scheduled for energy or ancillary services, the resource will be required to economically bid the rest of the resource's obligation for energy, ancillary services, reliability capacity and corrective capacity. Resource adequacy resources will have the same real-time must offer obligation as any other resource based upon day-ahead awards.

Resource adequacy resources will have the same real-time must offer obligation as any other resource based upon day-ahead awards. Resources must economically bid the full range of their reliability capacity and imbalance reserve awards into the real-time market. Real-time must offer obligations apply in the hourly intervals that a resource has a day-ahead schedule. Additional detail on must offer obligations for resources providing flexible resource adequacy is outlined in section 4.2, below.

Standard must offer obligation

The CAISO performed a comprehensive review of must offer obligations for all resource types in the tariff and Reliability Requirements BPM and believes the current must offer obligations can be simplified to provide market participants more clarity when determining the must offer obligations for different resource types. To simplify the must offer obligations, the CAISO proposes a standard must offer obligation into the day-ahead market that would apply to all resources unless specified by CAISO under a tariff exemption by resource type.[33]

> **Standard day-ahead must offer obligation:** Economic bids or self-schedules for all RA capacity for all hours of the month a resource is not on outage. [34]

Some stakeholders suggested the 24 by 7 must offer obligation does not align with the future makeup of the RA fleet, in which many resources will have use- or availability-limitations. The CAISO recognizes certain resources require variations to the standard must offer obligation and identifies these below. However, the standard must offer obligation into the day-ahead market remains 24 by 7 for most resource types. While the makeup of the resource fleet is becoming increasingly use- and availability-limited, the CAISO believes most resources should still bid into the day-ahead market for all hours the resource is not on outage. A resource should have bids

[33] The CAISO is not proposing changes to how load-following metered subsystems are treated under the existing tariff section 40.2.4.

[34] Outage refers to both planned and forced. If a resource is on outage, whether it is planned or forced, it should not be bidding that capacity into the market because it would not be able to deliver it.

in all hours it is available, such that the day-ahead market can determine when the resource is needed over the course of the day and schedule it appropriately.

Rather than modifying the day-ahead 24 by 7 must offer obligation, the CAISO believes modifying the MCC buckets would more appropriately address the increased amounts of availability-limited resources on the system. In its Order Instituting Rulemaking in the RA proceeding, the CPUC lists potential modifications to the MCC buckets as an option to consider when structurally changing the RA program in response to the rapidly changing resource fleet. [35] Redefining the MCC buckets, coupled with a 24 by 7 must offer obligation into the day-ahead market could be beneficial because resources with limited availability could contribute to RA needs consistent with their energy limitations, while still providing the CAISO market the ability to determine the hours the resource is needed over the course of the day. Additionally, this approach would benefit LSEs by providing more guidance into resource attributes needed to increase the possibility of passing the portfolio assessment, as discussed in Section 4.1.3.

Bid Insertion Proposal

The CAISO is proposing revisions to the bid insertion rules. Although the CAISO currently requires RA resources to economically bid or self-schedule into the market, it also supplements those bidding obligations with bid insertion provisions for non-use limited resources. The CAISO proposes to continue applying bid insertion to all RA resources in the day-ahead market, with minimal exemptions described below. Applying bid-insertion will ensure that resources have bids in the market and that outages would be reported to avoid market dispatch, enhancing the CAISO's ability to identify forced outages.

The CAISO allows resources with certain use limitations to include approved opportunity costs in their market bids. The policy is designed to ensure the more effective and efficient use of resources in the market and to facilitate regular and consistent market participation from resources with certain use limitations. Conditionally available resources, which have regulatory or operational limitations that do not qualify as use-limited, would not be exempt from bid insertion.[36] Conditionally available resources are able to use outage cards to manage their conditionally available outages and derates. The CAISO requires that conditionally available resources submit outage cards when unavailable, similar to all other resources on the system. The CAISO proposes not to exempt use-limited resources or conditionally available resources from the standard must offer obligation or bid insertion.

Variations to Standard Must Offer Obligation and Bid Insertion Proposal

The CAISO recognizes that not all resource types are physically capable of meeting the proposed standard must offer obligation, or require variations to the standard must offer obligation to provide the needed attributes of system and local RA. Therefore, the CAISO proposes a limited list of variations to the standard must offer obligation outlined in Table 12.

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[35] CPUC Order Instituting Rulemaking, November 13, 2019.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K527/319527428.PDF

[36] Tariff Definition of Use-Limited Resource and Conditionally Available Resource:
http://www.caiso.com/Documents/AppendixA-MasterDefinitionSupplement-asof-Sep28-2019.pdf

These resource types will still be subject to must offer obligations, but they will be defined by the CAISO based on the characteristics of the resource type.

The CAISO also recognizes the need to specifically define the bid insertion rules for resources that fall outside the categories of non-use-limited or registered use-limited. For example, it may not be appropriate to apply bid insertion to resources with variable output. Therefore, the CAISO also includes bid insertion exemptions listed in Table 12. If a resource is exempt from bid insertion, the CAISO would not insert bids into the day-ahead market for these resources in the event that required amounts of RA capacity are not offered into the day-ahead market. This table summarizes day-ahead market must offer obligations and bid insertion rules only.

The CAISO initially proposes to generally define the following variations to the must offer obligations and bid insertion into the day-ahead market based on resources type and seeks stakeholder feedback on this list, including modifications or additions. Resources exempted from the standard must offer obligation will still be required to offer into the CAISO market, but must do so as described in Table 12 and the paragraphs below.

Table 12: Variations to Standard Day-Ahead Must Offer Obligation and Bid Insertion Proposal

Resource Type	DA MOO	DA Bid Insertion
Eligible Intermittent Resource	May, but not required to, submit Bids in the Day-Ahead Market	No
NGR	Standard DA MOO plus MOO should reflect charge and discharge capabilities and resource must be non-REM[37]	Yes[38]
PDR[39]	CAISO will defer to program parameters established by the LRA. If none established, resources must follow the standard must offer obligation [40]	No
Participating Load	Participating load that is pumping load shall submit Economic Bids for Energy and/or a Submission to Self-Provide Ancillary Services in the Day-Ahead Market for its	No

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[37] Additional detail on potential solutions for market participation of storage resources is included in section 4.1.7.
[38] NGR resources currently do not have default energy bids (DEBs). Energy storage DEBs are proposed in ESDER 4 and once implemented will allow energy storage resources to receive bid insertion as part of this proposal.
[39] Refer to Energy Storage Distributed Energy Resources Phase 4 initiative for developments on bidding obligations for PDR under an ELCC counting methodology. In that initiative, CAISO is proposing potential modifications to must offer obligations for variable-output DR in the ESDER 4 stakeholder process, including bidding requirements and submission of forecasted capability. ESDER Stakeholder Initiative Webpage: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx
[40] PDR bidding requirements are specified in CAISO tariff Section 30.6.1 – Bidding and Scheduling of PDRs.

	Resource Adequacy Capacity that is certified to provide Non-Spinning Reserve Ancillary Service.	
RDRR	May, but not required to submit Bids in the Day-Ahead Market	No
Regulatory Must Take (RMT)	Standard MOO	No
Run-of-River Hydro	May, but not required to, submit Bids in the Day-Ahead Market	No

The following paragraphs include additional detail and rationale on the variations outlined in Table 12 above.

The CAISO proposes that for resources participating under the NGR model, the must offer obligation reflect both the charge and discharge capabilities of the resource so the CAISO can fully optimize the resource. To do so, the CAISO must have bids available for the unit's full capability. Bidding full charge and discharge capability will allow the CAISO to ensure fuel sufficiency for the resource. At this time, the proposal would also apply for battery storage resources participating under the NGR model regardless of the point of interconnection (*i.e.* transmission or distribution), and the CAISO is considering how it would apply to other technology types that may participate under NGR in the future.

Additionally, the CAISO has limited NGR eligibility for system RA to resources under the non-regulation energy management (non-REM) option. The CAISO cannot maintain system reliability over-relying on resources limited to providing regulation only. REM management resources are neither required, nor capable, of providing energy needed to meet the energy needs of system. Therefore, the CAISO has limited the system RA eligibility of NGRs to NGRs with the non-REM option.

A few resources will continue to have a real-time must offer obligation for RA capacity, including RDRRs and resources with intra-hour variability. The CAISO must maintain the real-time must offer obligation for RDRR resources. Unlike other RA resources, RDRR is not required to participate in day-ahead and is only available in real-time if the CAISO declares a warning or emergency. Therefore, the CAISO must ensure RDRR resources continue to have a real-time must offer obligation to ensure they are available in real-time if needed.

The CAISO must also maintain the real-time must offer obligation for resources with intra-hour variability, such as eligible intermittent resources and run-of-river hydro. Run-of-river hydro resources have similar operating characteristics to wind and solar because they have limited ability to control output from one interval to the next. It is optional for eligible intermittent resources to bid into the day-ahead market. In real-time, they are scheduled based on a forecast provided by the CAISO. This ensures feasible real-time dispatches that reflect intra-hour variability. The CAISO does not currently receive forecast data for run of river hydro or have the ability to provide forecasts for them. Therefore, run-of-river hydro cannot be treated as a VER due to lack of data availability. However, they can be treated similarly for the purposes of the must offer obligation. The CAISO proposes run-of-river hydro submit their own forecast of resource output to set the upper economic limit on bids. Eligible intermittent resources and run-of-river hydro would, therefore, not have a day-ahead must offer obligation, and would have a real-time must offer obligation up to their forecasted amount.

4.1.5. Planned Outage Process Enhancements

The CAISO considered modifying its planned outage provisions to correspond with the proposed modifications to its RA counting rules and assessments. The CAISO describes proposed changes to its planned outage provisions in the following section and provides relevant background on the current provisions.

Stakeholder feedback

In the fourth revised straw proposal, the CAISO put forward two new planned outage processes based on stakeholder proposals[41] to facilitate outage coordination and provide the greatest certainty regarding the timing of planned outages to both the CAISO and resource SCs. Option 1 established a planned outage reserve margin for off-peak months. Option 2 established a replacement marketplace conducted by the CAISO. Stakeholder feedback on these options is generally divided. Many stakeholders, including SCE, Calpine, MRP, CalCCA, and Wellhead offer some level of support for Option 1. The basis for support includes the simplicity offered by Option 1, the fact that this option improves capacity price transparency by removing any embedded costs to cover planned outage replacement, and that Option 1 eliminates any incentive to withhold excess capacity from the bilateral capacity market. Alternatively, SDG&E CPUC staff, DMM, and Public Advocates Office offered some level of support for Option 2. The basis their support included that Option 2 appears to apply more direct causation to the resources taking the planned outages and offered more of a market based solution.

In addition to considering stakeholder feedback, the CAISO has looked to other ISOs/RTOs for guidance on how they have approached this issue. Based on the CAISO's review of other ISO/RTOs, CAISO is uniquely situated. More specifically, the CAISO's planned outage options are constrained by the monthly nature of the RA program. All other ISOs/RTOs conduct RA procurement annually, potentially including seasonally different RA requirements. Additionally, other ISO/RTOs can require up to two years of notice for planned outages. This allows the ISO/RTOs to include those planned outages in LOLE studies when conducting annual capacity procurement. Because other LSEs have much longer visibility into the RA obligations of resources, the planned outage procedures are much cleaner. However, the CAISO does not know which resources will be RA resources until 45 days prior to the month. This timeline creates a complicated overlap between the CAISO's planned outage and RA processes. To the greatest extent possible, the CAISO will attempt to mitigate this overlap.

Based on the CAISO research and stakeholder feedback, the CAISO, will pursue Option 1, developing an additional planned outage reserve margin for the non-summer months. Although the cost causation arguments in support of Option 2 appear persuasive *prima facie*, the CAISO

[41] In addition to these two proposals, the CAISO also explored numerous other options in prior straw proposals. However, given stakeholder feedback, the CAISO is currently only evaluating the two most recent options.

believes the potential benefits of Option 2 are far outweighed by its complexity – requiring the development of a substitute capacity market that could be subject to market power – and creates additional incentives to withhold capacity from the bilateral resource adequacy capacity market. The argument in support of Option 1 and the specific concerns with Option 2 are explained in greater detail below.

Although the CAISO is proposing Option 1 in this current straw proposal, it remains open to one other option: Keep the existing planned outage process unchanged. Over the course of the stakeholder process, the CAISO has offered numerous alternatives based on both CAISO and stakeholder proposals. To date, stakeholders have rejected the proposals or have been highly divided in their approval or disapproval of the options offered. The CAISO has acknowledged that the existing planned outage substitution process is complex and creates risk that previously approved planned outages may be cancelled. Although the existing process has it challenges, the CAISO is prepared to recognize that may be the best that can be done under the current monthly RA program. Therefore, should stakeholders reject Option 1, the CAISO will leave the existing process unchanged and eliminate this element of the overall proposal.

Stakeholders continue to comment on the CAISO's view that, depending on the circumstances, it can violate the tariff for a generator or transmission operator to submit a forced outage after the CAISO has rejected the same outage when submitted as a maintenance outage. This topic of "planned-to-forced" outage reporting has been the subject of even more attention given the recent appeal to the CAISO executive appeals committee of a CAISO revision to the business practice manual for outage management.[42] The committee's decision directed staff to consider the following as expeditiously as practicable:

> What amendments are necessary in the outage reporting sections of the ISO tariff to further clarify when planned-to-forced outage reporting is prohibited and when it is permitted. Such amendments to consider include, but are not limited to, amendments to the definitions of planned and forced outages, as appropriate. This process also should consider resolving any other potential ambiguities in section 9 of the tariff, as well as consideration of further illumination of the factors used in determining whether to approve or reject a planned outage, whether in the tariff or BPM, as appropriate.[43]

As a result of stakeholder feedback and the appeals committee's decision, the CAISO will address the planned-to-forced outage reporting issue within this RA Enhancements stakeholder process. Specifically, the outage definitions proposed in section 4.1.2 will clarify the planned and forced outage definitions and a properly designed UCAP construct will likely eliminate the incentive for market participants to engage in problematic planned-to-forced outage reporting, which in turn may influence the relevant outage reporting tariff provisions. Due to the relationship between outage reporting and the rest of the RA Enhancements proposal, it is most appropriate to address this issue within this initiative and its timeline.

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[42] Details of that appeal, which related to proposed revision request 1122, are available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=D8E40756-EA62-4851-B528-3F2D6DD04728

[43] http://www.caiso.com/Documents/ExecutiveAppealsCommitteeDecision-PRR1122-Mar112020.pdf

Background

The CAISO's Planned Outage Substitution Obligation (POSO) process is codified in CAISO tariff sections 9.3.1.3 and 40.9.3.6 and the Outage Management BPM.[44] RA resources currently enter planned outages into the CAISO Outage Management System (OMS). The CAISO's Customer Interface for Resource Adequacy (CIRA) system runs a daily POSO report and determines the planned outage substitution need. The POSO process is currently conducted on a first-in, last-out basis.[45] Therefore, resources submitting planned outages earliest will have the greatest likelihood of taking their planned outages without substitution requirements. The POSO process compares the total amount of operational RA capacity to the total system RA requirement.

As noted previously, LRAs establish system RA requirements based upon CEC monthly peak forecasts, which are updated 60 days prior to the start of each delivery month. If, after removing all planned outages, available capacity is less than the RA requirement, the CAISO assigns substitution obligations for resources seeking to take planned outages.

Objectives and Principles

The CAISO lists the following objectives and principles that inform changes to its planned outage provisions. Modifications to the CAISO planned outage provisions should:

- Encourage resource owners to enter outages as early as possible
- Avoid cancellation of any approved planned outages to the extent possible
- Minimize or eliminate the need to require substitute capacity to greatest extent possible
- Identify specific replacement requirements for resources requiring replacement
- Allow owners to self-select, or self-provide, replacement capacity
- Include development of a CAISO system for procuring replacement capacity

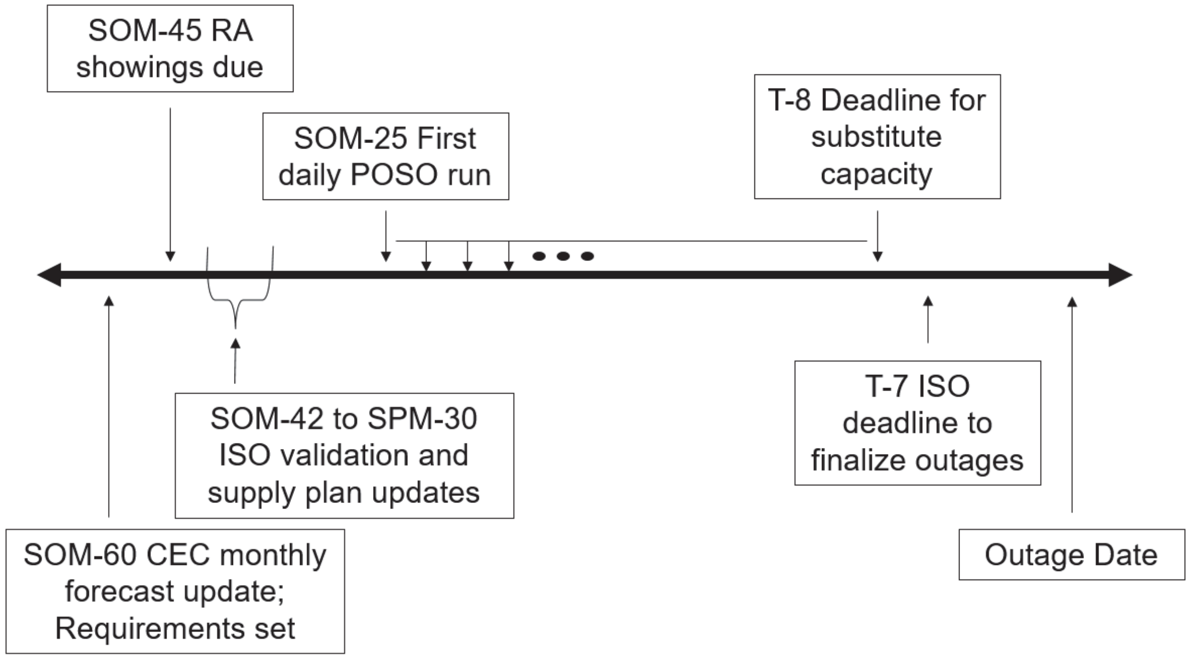
Current Planned Outage Substitution Obligation Timeline

The current POSO timeline is provided in Figure 5 below. The current timeline provides the first POSO assessment at T-22, or 22 days prior to the start of the RA delivery month, for all outages submitted prior to T-25. This is the first instance when resource owners are provided with indication of any POSO replacement obligations. Resource owners are allowed to provide replacement capacity through the T-8 timeframe, and the CAISO finalizes replacements and outages at T-7.

[44] Outage management BPM found here: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Outage%20Management

[45] CAISO will first request the resource providing RA Capacity with the most-recently-requested outage for that day to provide RA Substitute Capacity and then will continue to assign substitution opportunities until the ISO has sufficient operational RA Capacity to meet the system RA requirement for that particular day.

Figure 5: Current POSO timeline



Proposed Modifications to the Planned Outage Process

Based on stakeholder comments, the CAISO is proposing several changes to ensure planned outages can be taken with minimal cancellation risk after their initial approval. The CAISO also is attempting to remove obligations for outage replacement to the greatest extent possible. The CAISO proposes to redesign the planned outage process to reflect system UCAP targets rather than traditional NQC targets. This proposed change will better align with the counting rules and RA assessments proposal to incorporate forced outage rates in capacity valuation and assess resource adequacy on a UCAP basis.

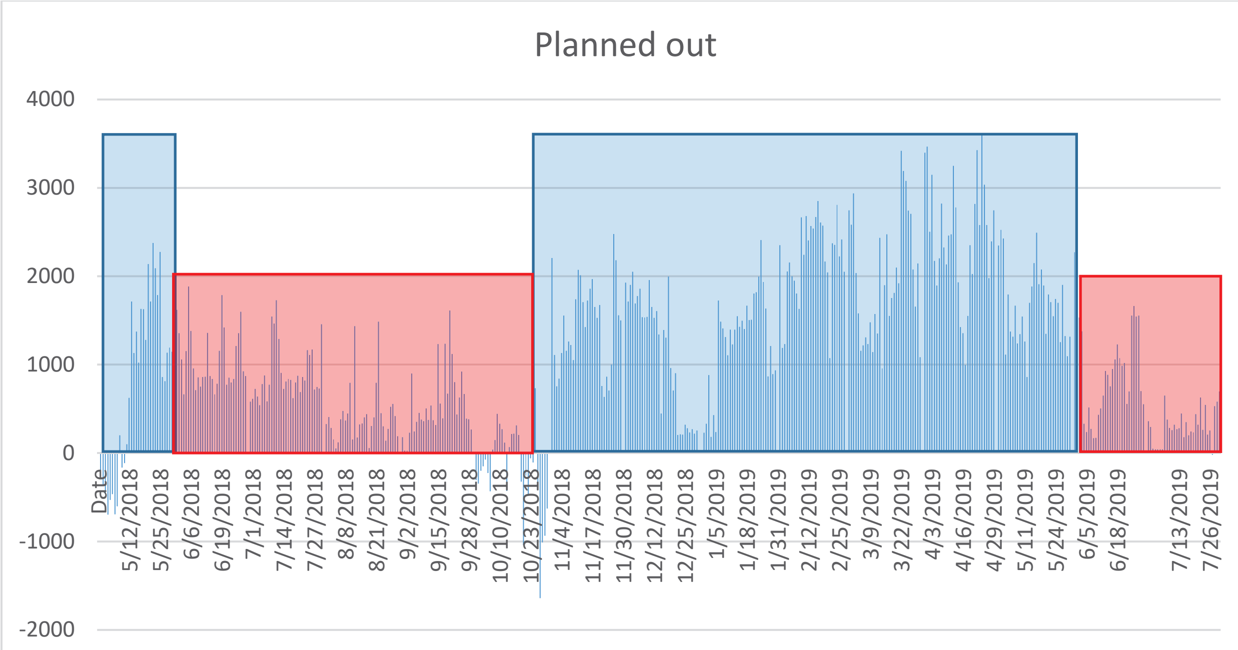
Revised RA Planned Outage Process

To facilitate outage coordination and provide the greatest certainty regarding the timing of planned outages to both the CAISO and resource SCs, the CAISO is considering establishing a planned outage reserve margin for off-peak months.

Including planned outage planning in procurement requirements

The CAISO proposes to establish two new elements of the RA program with respect to planned outages. First, the CAISO would no longer allow for anything other than short-term and off-peak opportunity outages between June 1 and October 31. As can be seen from Figure 6 below, the vast majority of planned outages occur during off-peak months. Additionally, the off-peak months also provide the greatest opportunity to procure low cost capacity to ensure adequate capacity is available to the CAISO.

Figure 6: Approved Planned Outages (Both with and Without Substitution)[46]



Therefore, the CAISO proposes that UCAP capacity requirement would increase during the non-summer months, creating a well-defined planned outage reserve margin. To be clear, the higher UCAP requirement in the non-summer months does not mean that the CAISO's overall capacity needs are higher in these months. Instead, the higher UCAP requirement is to reflect that all maintenance outages on RA capacity will have to occur during this time, meaning that the planned outage rate on the RA fleet during this time will be substantially higher than during the peak summer months. No substitute capacity is allowed or required for an outage. The CAISO's proposed capacity outage calendar would track all planned outages for each day until RA showings are made for a given month. Once RA showings are made, the CAISO will track how much additional capacity can take a planned outage under the planned outage reserve margin. The CAISO is not, at this time proposing a specific reserve margin. The reason for this is that it is not possible to declare a fixed number based on historic data. Instead the size of the planned outage reserve margin should be based on a balance of LSE costs and providing reasonable opportunities for resources to undertake needed maintenance. For example, if the final decision is that the planned outage reserve margin is zero, then the CAISO could deny or cancel all planned outages for RA resources. However, this bookend has the down side of potentially leading some resources to be unable to sell RA for a whole month due to a couple day planned outage. Alternatively, should the planned outage reserve margin be set at 10,000 MW, then the CAISO would likely be able to approve most planned outage requests, but this opportunity would come at significant rate-payer expense. Further, the planned outage reserve margin need not be fixed for all months. For example, it could be set at 5,000 MW in January, taper down to 3,000 MW in March, down to zero in May, and then increase again over the

[46] Observations with negative values represent days when the quantity of substitute capacity exceed the quantity on approved planned outage.

remaining months of the year. Therefore, the CAISO proposes to work with LRAs and other stakeholders to determine the best balance between these extremes.

The CAISO will review outage requests as they are submitted. Outage requests submitted prior to RA showings will either be approved or denied based on the CAISO's reliability assessment. The CAISO will not wait for RA showings to make this determination. The difference between this and current practices is that the CAISO will no longer issue POSO notifications at T-22 days prior to the month for outages requested by T-25. When RA showings are made, the CAISO will subtract all planned outages on RA showings from the planned outage reserve margin for each day in the RA month. If on a given day the approved planned outages for RA resources exceeds the planned outage reserve margin, then the CAISO will not allow any additional planned outages for that day. If the approved planned outages are less than the planned outage reserve margin, the CAISO will allow for additional planned outages on a given day for up to the remaining difference. Once subsequent planned outage requests reach the remaining planned outage reserve margin, the CAISO will automatically reject all additional planned outage requests. However, even if additional planned outage reserve margin remains, all planned outages will be subject to the CAISO's reliability assessment and may be denied for potential adverse reliability impacts. Finally, the CAISO will retain discretion to grant or deny all opportunity outages based on CAISO engineering assessment, regardless of threshold.

Table 13 below provides several examples of how the CAISO would assess a 300 MW resource requesting a planned outage. This example assumes a 3,000 MW planned outage reserve margin based on the data shown in Figure 6 above.

Table 13: Examples of how CAISO will assess planned outages with a planned outage reserve margin

Timing of submission	Outage Calendar requests	Remaining planned outage reserve margin	Approved or rejected
Request made January 1 for outage on June 1	0 MW	NA	Rejected
60 days prior to month	2,500 MW	NA	Based on reliability assessment
60 days prior to month	3,500 MW	NA	Based on reliability assessment
20 days prior to outage date	2,000 MW	1,000	Based on reliability assessment
20 days prior to outage date	2,800 MW	200	Rejected

1 day prior to requested outage	3,000 MW	0	At the discretion of the CAISO

For purposes of UCAP calculations, any planned or opportunity outage approved by the CAISO will not impact the resource's UCAP calculation. However, all rejected planned outages, if taken, may count against the resource in it UCAP calculation.[47] This applies regardless of the timing of the outage request or the ultimate RA status of a resource.

Although, this option would require higher overall procurement, there are several other potential benefits to load. First, the CAISO's proposal eliminates all planned outage substitution. This removes both the incentive for LSEs to withhold capacity from the market to provide substitute capacity and the need for resources to include a risk premium in capacity contracts to cover any potential costs of replacement capacity. As a result, the supply of capacity in the bilateral market should increase and hidden costs included in the contracts should decrease. Instead, all excess capacity should be more readily available for sale in the bilateral capacity market, maximizing LSEs' opportunities to find capacity when needed at a lower price. These benefits can be captured in both peak and off-peak months. Under the existing rules, substitution may be required in all months. Eliminating substitution rules in their entirety should also free up additional capacity during summer months, increasing overall supply and lowering costs. Finally, because the CAISO proposal would only include a planned outage focuses on off-peak months to minimize the potential for increased capacity prices to LSEs.

The alternative the CAISO considered from the Fourth Revised Straw Proposal was to develop a new procurement tool designed to procure planned outage substitution capacity.[48] The procurement would take place for daily substitute capacity obligations. This new procurement option, and the tool the CAISO would employ, would be separate from its existing CPM authority. Instead, the CAISO would have served as a facilitator to enable planned outages. Resource participation to provide daily substitute capacity via a competitive solicitation process would have been completely voluntary.

Although this option may seem conceptually easy to understand, there are numerous complex policy issues that needed to be resolved, and the CAISO would have to build a complex and costly capacity clearing mechanism when the benefits are unclear and the potential downsides appear significant, such as potential replacement costs and market power concerns. However, stakeholders offered little in the way of how these issues would be resolved. For example, stakeholders were split over making participation in the substitute capacity market optional or mandatory. Additionally, there was no discussion about how to resolve potentially withholding capacity from the market (except for making participation mandatory) to supplement another outage for the same SC. This can lead to some days where the price of substitute capacity is

[47] The final determination of if the outage would count in the resource's UCAP calculation depends on the final UCAP calculation methodology.
[48] The SDG&E proposal suggested the CAISO develop this tool for both planned and forced outages. However, the CAISO's proposal will not extend to forced outages. The basis for this decision is discussed later in this proposal.

zero and other days where it could be priced at the peak. There was no stakeholder discussion regarding ways to set daily price caps or monthly earnings caps.

Ultimately, the CAISO remains concerned that planned outage replacement under this type of tool can lead to planned outage costs becoming disincentives to resources doing maintenance. Additionally, since resources will not know the cost of replacement capacity, they will be forced to include higher risk premiums in their RA contracts to compensate for the risk that they may be required to procure substitute capacity at a premium price. This is where the cost causation arguments in support of a secondary substitute capacity start to break down. First, at the end of the day, all costs are ultimately passed onto to load. So, while a specific generator may pay a price for substitute capacity, that resource will build that cost into its overall RA cost, which is then passed on to rate-payers. Second, this secondary market creates incentives for LSE to withhold some capacity to mitigate replacement cost risk. In these instances, the resource taking the planned outage is faced with one of two options 1) withhold capacity from the RA market to mitigate price risk or 2) risk looking for substitute capacity in a scarce market. The CAISO is concerned that running a daily replacement capacity market will require a daily price cap, a monthly earning cap, or both, which will prove costly and potentially result in resources forgoing maintenance. This risk is mitigated by the potential impacts to a resources UCAP if it is forced out due skipping maintenance. However, these risks can be avoided entirely by simply establishing a planned outage reserve margin and eliminating planned outage substitution requirements.

Finally, this option has an additional downside in that it does not resolve the issue of LSEs withholding capacity to self-insure against replacement costs. In fact, given that the resource SC will be charged directly for the substitute capacity, it provides an incentive for that SC to have additional capacity on hand to minimize the price and maximize the probability that capacity is available when requesting planned outages.

Opportunity Outages

The CAISO currently allows both short-term opportunity and off-peak outages. The CAISO proposes to maintain both of these options as opportunity outages described in section 4.1.2, regardless of which planned outage option is ultimately selected. Further, as noted in section 4.1.4, the CAISO is proposing to modify the RA must offer obligation with the introduction of the day-ahead market enhancements. With limited exceptions, if resources do not receive any day-ahead awards, the resource will be eligible to take a single day opportunity outage. These opportunity outages may be requested after the day-ahead market closes and are subject to CAISO review and approval. If approved, no replacement capacity is required for these outages. However, because no replacement is required, these outages are only permitted for a single day and resources must participate in the subsequent day-ahead market.

Planned Outage Outlook Transparency

The CAISO proposes to offer greater visibility into how much resource adequacy capacity is shown relative to the resource adequacy requirements. The goal is to provide resources greater transparency regarding available capacity well in advance of planning outages. Specifically, CAISO proposes to develop a calendar that shows in advance and on a daily basis, the potential availability of additional system RA headroom. This RA headroom should allow resources to identify potential calendar dates with RA headroom in advance of requesting planned outages, thus mitigating replacement obligations and helping the CAISO maintain adequate available capacity. If the calendar shows no available headroom, then any RA resource requesting a planned outage will be required to show substitute capacity.

Outages will be approved and denied through the planned outage tool discussed above. The CAISO will continue to evaluate and accept outages and substitute capacity and adjust the outage calendar on a first-in, last-out basis. Thus, resources submitting outage requests will be assessed first, making it less likely the CAISO will deny their outage or require substitute capacity compared to later requesting resources. The CAISO will continue to allow resources taking outages requiring replacement to self-provide substitute capacity for any outages requiring replacement.

Figure 7 demonstrates the conceptual planned outage outlook calendar. The CAISO proposes to publish this type of calendar including daily MW values for UCAP headroom in excess of system RA requirements. The specific content of this calendar will ultimately be driven by the planned outage option selected, however, the goal of providing this type of information is to assist resource SCs in planning outages and ensuring proper resource maintenance.

Figure 7: Example substitution availability calendar

2 Headroom: 25 MW	3 Headroom: 205 MW	4 Headroom: - MW	5 Headroom: - MW	6 Headroom: - MW	7 Headroom: 350 MW	8 Headroom: 7 MW
9 Headroom: 30 MW	10 Headroom: 712 MW	11 Headroom: 145 MW	12 Headroom: 320 MW	13 Headroom: 200MW	14 Headroom: - MW	15 Headroom: - MW

4.1.6. RA Import Requirements

Introduction

In this fifth revised straw proposal, the CAISO provides additional refinements to the proposed RA imports provision after further consulting with stakeholders and considering guidance from the CPUC's track 1 resource adequacy decision on RA imports.[49] This revised proposal attempts to balance the CAISO's need for reliable and dependable RA imports, with the need for efficient and liquid markets recognizing that California competes for imported energy and transmission across a broad and diverse west-wide market. Given California's long-standing reliance on RA imports to support reliability, the CAISO must ensure there is sufficient, verifiable, and dependable RA import capacity secured in advance to meet California's capacity and energy needs, particularly as competition for supply tightens across the west.

The proposed modifications support and build on the CAISO's RA import market participation rules and align directionally with the RA program rule changes the CAISO has been advocating in the CPUC's Track 1 and Track 3 RA proceedings. CAISO and CPUC alignment on RA imports coming out of the CPUC's Track 3 RA proceeding is critical to ensure comparable treatment across all LSEs and avoid disconnects between the CAISO's and CPUC's RA import rules and regulations.

Background

LSEs can meet system RA requirements with a mix of RA resources, including imports from outside the CAISO balancing authority area. Import RA resources were used to meet an average of around 3,600 MW (or around 7 percent) of system RA requirements during the peak summer hours of 2017. In the summer of 2018, this increased to an average of around 4,000 MW (or around 8 percent) of system resource adequacy requirements.[50] In 2019, this increased to about 4,700 (or about 10 percent).[51] Thus, import quantities are an integral component of the RA program, and their availability and dependability affect the RA program's ability to ensure reliability.

Today, the CAISO tariff does not require that RA import resources be resource-specific or specify they represent supply from a specific balancing authority area (BAA). RA import resources are only required to be shown on RA supply plans with associated maximum import capability allocations, and make offers as shown at a specific intertie point into the CAISO's system. Import RA is not obligated to bid into the real-time market if it is not scheduled in the day-ahead integrated forward market or residual unit commitment process.

The current RA import provisions can undermine the integrity of the RA program and threaten system reliability. The CAISO's Department of Market Monitoring (DMM) expressed similar

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[49] CPUC Track 1 Decision, D.20-06-028

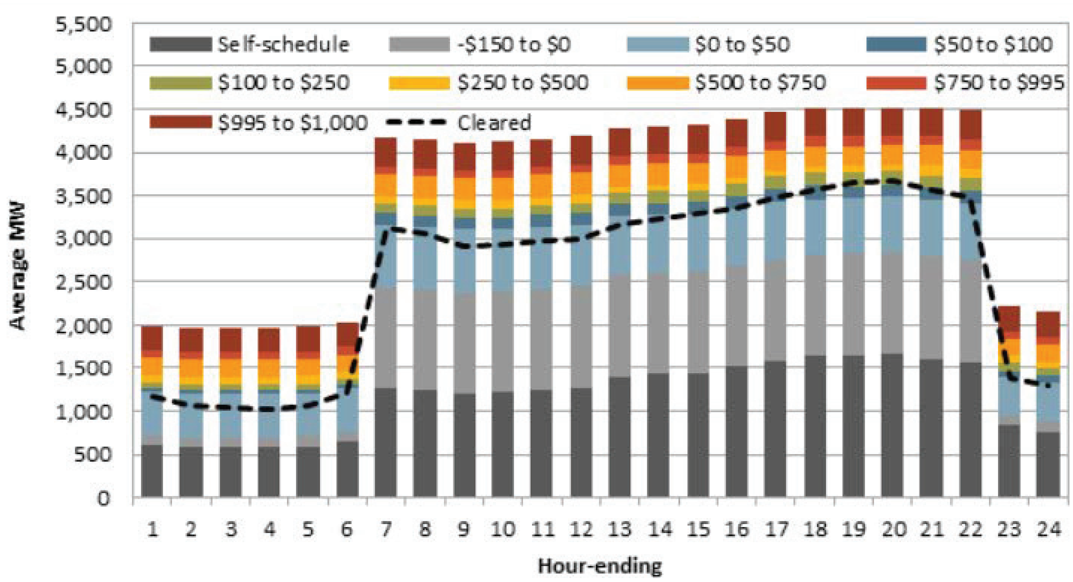
[50] 2017 CAISO DMM Annual Report, p. 259: http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

[51] 2019 CAISO DMM Annual Report, p. 266: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

concerns in its September 2018 DMM special report on import RA.[52] In that report, DMM explained the existing rules could allow for some portion of resource adequacy requirements to be met by import RA that have limited availability and value during critical system and market conditions. For example, DMM indicated non-resource specific RA imports could satisfy their RA must offer obligation by routinely bidding significantly above projected prices in the day-ahead market so they do not clear the market, relieving them of any further offer obligations in real-time. DMM said this is possible because non-resource specific RA imports can be speculative and do not have bid cost recovery or bid cost verification, meaning they can bid up to the bid cap to avoid delivery.

The DMM provided specific examples of these bidding behaviors in its comments on the recent CPUC Proposed Decision clarifying RA Import rules (R17-09-020). Figure 4.7.1 shows the average hourly RA imports offered into CAISO's market at various price levels.[53] This information provides additional evidence that around 1000-1200 MW RA imports were submitting bids at bid levels in excess of $500/MW in August of 2018.

Figure 8: Average hourly RA imports offered by price bin (weekday hours) August 2018



On February 28, 2020, the CAISO submitted a proposal in the CPUC's RA proceeding, R.19-11-009.[54] The CAISO's proposal specifically addressed the need to eliminate speculative import RA supply by strengthening import RA qualification and verification requirements. The CAISO's proposal included recommendations for priority actions the CPUC should adopt both to

[52] DMM Special Report: Import Resource Adequacy, September 10, 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf
[53] DMM comments on CPUC Proposed Decision clarifying RA Import rules (R17-09-020). September 26, 2019: http://www.caiso.com/Documents/CommentsofDepartmentofMarketMonitoringonProposedDecisionClarifyingRAImportRules-R17-09-020-Sept262019.pdf
[54] CAISO Resource Adequacy Track 1 Proposal (R.19-11-009) Feb 28, 2020: http://www.caiso.com/Documents/Feb28-2020-Track1-Proposal-R19-11-009.pdf

establish stricter RA program rules and to collect data necessary to enforce those rules. The CAISO proposed that the CPUC require that RA imports:

1. Provide source specific information at the time of the resource adequacy showings. Source specification can be a specific generating unit, specified aggregation or system of resources, or a specified balancing authority area, but should be clearly identified in advance.
2. Provide an attestation or other documentation specifying the resource adequacy import is a specific resource, aggregation of physically linked resources, or capacity in excess of the host balancing authority area or supplier's existing commitments that is dedicated to CAISO balancing authority area needs; and
3. Can be delivered to the CAISO balancing authority area boundary via firm transmission.

The CPUC in Decision D.20-06-028, updated its requirements for import resources to count towards meeting jurisdictional LSEs' RA requirements. Specifically, for the 2021 RA year, only LSE contracts with resource specific import resources – defined by the CPUC as only dynamic and pseudo-tied resources – would allow economic bids (or self-schedules). LSE contracts with non-resource specific resources would only permit such resources to self-schedule or submit economic bids between $-150 and $0. The CPUC noted it sees merit in the CAISO's proposal. However, it believes more robust verification and visibility is necessary before implementation.[55] In addition to coordinating with the CPUC in the RA proceeding to ensure the RA requirements are aligned, the CAISO anticipates it will require tariff changes to support the RA import requirements it discussed in the CPUC proceedings. Therefore, the CAISO has further developed its proposal, providing additional details to support full implementation of new import eligibility rules including an interim real-time must offer obligation that would be in effect until the CAISO implements the Day-Ahead Market Enhancements (DAME) policy in which it proposes to adopt the imbalance reserve product that will be the basis for the real-time must offer when those changes are implemented. Additionally, the CAISO has continued researching the availability and need for firm transmission service and transmission tagging requirements. These proposed requirements are included below.

RA Import related concerns and issues under review

The CAISO's review of the current RA import provisions is focused on determining where they cause reliability concerns and how to mitigate those concerns. The CAISO has identified two areas of concern with the current RA import provisions:

1. **Lack of specification and double counting of RA import resources**:

The CAISO's current RA tariff provisions and existing CPUC RA program guidelines allow non-resource specific resources to qualify as System RA capacity. As indicated above, RA imports are not required to be resource specific or to represent supply from a specific balancing area. Instead, they are only required to be shown as sourced on a specific intertie into the CAISO system. Thus, the CAISO may not know what specific resources are supporting an RA import.

[55] CPUC Track 1 Decision, D.20-06-028

Because of tightening supply in the West, the CAISO is increasingly concerned about the potential that non-resource specific RA imports are not supported by real, physical capacity dedicated only to the CAISO LSEs, *i.e.*, these RA import commitments may be speculative and the capacity shown may remain unsecured at the time of the RA showing, or may be concurrently committed to serve other load.

Although the CPUC's recent decision, D.20-06-028 directed that LSE contracts with non-resource specific resources require such resources to self-schedule or bid at or below $0/MWh, there is no assurance that these non-specified resources are backed by physical resources that will actually be available when the CAISO needs them. Similarly, the CAISO is concerned that continuing to allow non-resource specific imports to qualify for RA without any source-specification may create the potential that the underlying resources may be double counted and unable to serve CAISO reliability needs, especially under stressed system conditions in the west. Double counting occurs when RA capacity is also sold or committed to a third-party in other regions or to other Balancing Authority Areas (BAA), while simultaneously being shown as CAISO RA capacity. The CAISO is concerned reliability risks will continue to exist as long as there is the potential for import RA supply to qualify without a forward resource specification requirement and a requirement the resource not be sold to another entity during the applicable RA period.

2. **Speculative RA import supply being used on RA showings**:

The CAISO believes that RA import provisions should foreclose (or at a minimum, discourage) speculative RA import supply. Speculative RA import supply can occur when RA imports shown on RA supply plans have no physical resources backing them up, and no firm contractual delivery obligations secured, which means such schedules are subject to being recalled or curtailed by a source or intervening BAA to meet its own needs, and/or are not afforded a curtailment priority comparable to that afforded a BAAs native load. Without resource specificity that is dedicated solely to the CAISO BAA and assurance that the contracted capacity is supported by reliable transmission service, RA imports are subject to double counting and may be speculative if transmission service is unavailable to deliver the needed energy on more constrained paths.

The CAISO previously described speculative RA import supply and noted that it shares DMM's concerns about speculative supply. Significant amounts of speculative supply supporting import RA could present reliability concerns. The CAISO's review of available evidence reflects frequent cases of relatively high priced DA bidding by non-resource specific RA imports. This conduct raises concern these non-resource specific RA imports represent speculative supply, as this bidding practice is a logical strategy any scheduling coordinator might use to meet the letter of the must-offer obligation rule but avoid an award from the CAISO market.

Objectives

The CAISO identifies the following general objectives to guide RA import rule modifications.

- Modify RA import provisions to ensure RA imports are backed by physical and verifiable capacity, are not speculative, are not "double-sold" or committed elsewhere, and are dependable and reliable.
- Treat RA imports more comparably to internal-CAISO RA resources, recognizing the CAISO competes for supply across a broad and diverse west-wide market.
- Coordinate import provisions with any related modifications being proposed through CAISO's extended EIM and DAME initiatives. Coordination between the RA Enhancements, DAME, and Extended Day-Ahead Market (EDAM) initiatives is vital to ensure all of the interrelated aspects work together without unintended consequences.
- Create requirements that track and reasonably assimilate the resource-specific showings and verification provisions of other ISOs and RTOs.

RA Import Proposal

The CAISO summarizes the key principles and elements of the CAISO's RA imports proposal in this fifth revised straw proposal as follows:

- RA imports must be verifiable and resource specific
  - Eligible resource-specific RA types include:
    - Resource-specific system resources (non-dynamic)
    - Resource-specific system resources (dynamically scheduled)
    - Pseudo-ties
      Note: Non-resource specific system resources will no longer qualify as RA import capacity
  - Non-dynamic resource specific system resources definition encapsulates (1) a single resource, (2) a specified portfolio of resources within a single BAA, or (3) a BAA's pool of resources

- The capacity underlying the RA import must be dedicated solely to the CAISO
  - An attestation requirement specifying the RA capacity is not sold or otherwise committed to any other entity and is not being used in connection with any other capacity or resource adequacy construct in the applicable RA compliance month.

- The RA import capacity must be dependable and deliverable
  - CAISO is considering requiring firm transmission service source to sink (*i.e.*, service that ensures the RA imports have the same curtailment priority afforded to the BAA's native load) on complete path (*i.e.*, all lines of interest, to ensure delivery to CAISO border) or,
  - Alternatively allowing requirement to be met with firm transmission service on last line of interest (last leg) to CAISO BAA. In the alternative case:
    - For example, require firm transmission service on BPA's southern interties (to COB and NOB) but allow non-firm service on upstream lines of interest

        - If only requiring firm transmission on last line of interest, consider appropriateness of other mechanisms to incent/promote delivery of RA import if service on an upstream line(s) of interest is curtailed because it is less than firm service
        - CAISO would monitor and consider if it must impose firm transmission service requirement on all lines of interest, source to sink, if curtailments occur under the proposed "last line of interest" alternative proposal
        - Require minimum day-ahead e-Tagging requirement of the firm transmission service on last line of interest; prudent to secure firm transmission service on all paths and in advance to avoid non-delivery and the potential for non-compliance penalties, if imposed.
    - Provisions to ensure RA import cannot be recalled or curtailed to meet a source or intervening BAA's own needs

- RA Import must offer obligation
    - Day-ahead must offer obligation
    - Interim real-time MOO requirement until CAISO implements the DAME which will redefine all must-offer obligations.

To support these proposed requirements, the CAISO anticipates the CPUC would adopt similar requirements. However, ultimately, the CAISO will require CAISO tariff changes to implement these requirements. The CAISO believes that that the collective impact of these tariff modifications will greatly reduce if not eliminate the potential for speculative import supply and double counting. The CAISO discusses each of the proposed modifications below.

Source specification requirements for all RA import supply dedicated solely to the CAISO

In light of the recent CPUC decisions and stakeholder feedback, the CAISO is committed to requiring broadly defined source specification for all RA imports so that real, physical supply is secured at the time of RA showings and is not speculative. Further, such capacity must be committed solely to CAISO LSEs and serve CAISO reliability. As indicated above, the CAISO does not know whether RA imports are being double counted under current RA import provisions, *i.e.*, whether import capacity shown for RA has been sold to a third party, or is being used to meet capacity or resource adequacy needs in another BAA or under another RA construct for the applicable RA period.

Under the CAISO's proposal, the following CAISO-defined imports types will qualify as resource-specific resource adequacy import resources: (1) Dynamic Resource-Specific System Resources or Pseudo-Tie resources, and (2) Non-Dynamic Resource-Specific System Resources. The CAISO fully supports Non-Resource Specific System Resources participating for economic energy, but to ensure RA imports are backed by specific units or an aggregation of units, the CAISO proposes here that RA imports must be resource specific, as either a pseudo-tie or dynamic, or non-dynamic resource specific system resources. Non-Dynamic Resource Specific Resources can be (1) a specific external resource, (2) a specified aggregation or portfolio of resources in a single external BAA,[56] or (3) if the BAA is the RA import supplier the BAA's pool of resources is supporting the RA import.

To achieve these objectives, the CAISO proposes two documentation requirements for RA import capacity. First, the CAISO proposes that all RA import suppliers specify via an attestation that the physical resource or resources that will be relied upon to meet the RA requirement state that the capacity has been secured at the time of the RA showings for the applicable RA showing period and has not been sold, and is not committed, to any other entity. The CAISO is considering the types of information that would be required for each category of RA import supply.[57]

To count as RA capacity, all import RA supply must provide the source specification and CAISO commitment certifications by the deadlines for the applicable year-ahead and month-ahead RA showings.

The CAISO will develop the specific wording of the attestation requirements in the tariff development process, but the CAISO intends to model them similar to provisions in other ISO/RTO tariffs and business practice manuals.

The CAISO recognizes there may be additional and appropriate costs associated with this more rigorous resource-specific standard, but by requiring source specification, import RA will be more on par with the quality and delivery obligations of CAISO internal resource adequacy resources. Adopting a source specification requirement will require host balancing authorities and suppliers to secure the necessary fuel and plan and position their resources to meet their own needs and their commitments to the CAISO BAA. Adopting requirements for forward source specification from real, physical resources committed to serving the CAISO will address both the speculative import supply and bidding behavior concerns because it helps ensure actual physical resource capacity is secured to serve California's reliability needs.

Non-specified energy contracts alone should not qualify for Import RA

Non-resource specific firm energy contracts cannot address speculative supply or double counting concerns. As such, non-resource specific system resources are not a substitute for

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[56] Import suppliers currently specify resource aggregations as a Non-Resource Specific System Resource. To facilitate the option of treating a resource aggregation as a resource-specific supply source, the CAISO proposes to expand the definition of non-dynamic resource-specific system resources to include resource aggregations or portfolios of resources in a single BAA. The resources supporting the aggregation or portfolio must be specified. The new the definition will allow aggregations of resource to be classified as resource specific.

[57] With the potential extension of the day-ahead market to EIM entities, the CAISO believes that, at minimum, RA import resources must specify the source BAA. The proposed source specification will help the CAISO verify that RA imports are not double counted for EIM entities' resource sufficiency tests. Without this rule, it would be possible for an EIM entity to count on capacity from a resource within its own BAA to pass the EIM resource sufficiency evaluation, while also showing the resource as import RA to the CAISO. This is not an appropriate outcome because the resource is incapable of physically meeting both the source BAA's needs *and* the CAISO's needs. The CAISO anticipates that requiring a designation of the source BAA is a good first step.

advance procurement of real physical, resource-specific capacity. Accordingly, contracts that do not identify or specify resources in support of the RA contact should not count as RA resources. Firm energy contracts and related hedging mechanisms can help mitigate day-ahead and real-time market price risk, but they cannot ensure that real physical supply is secured in advance, which is the purpose of the resource adequacy program. In the CPUC's Decision (D.) 05-10-042, it disallowed liquidated damages (LD) energy contracts from internal supply because of the potential for double counting. D.05-10-042 established that LD contracts (which are "non-resource-specific" contracts) would be phased out for resource adequacy purposes because they allowed the possibility of double-counting resources and were not subject to deliverability screens.[58]

Decision D.05-10-042 explains why the Commission accepted firm LD import energy contracts for resource adequacy purposes:

> *"Firm import LD contracts do not raise issues of double counting and deliverability that led us to conclude that other LD contracts should be phased out for purposes of RAR. We note that firm import contracts are backed by spinning reserves. Accordingly, we approve the exemption of firm import LD contracts from the sunset/phase-out provisions applicable to other LD contracts as adopted in Section 7.4.6."*[59]

It appeared the CPUC decision assumed because firm LD import contracts are backed by spinning reserves, the resource capacity underlying them could not be double counted as capacity resources, once for CAISO LSEs and again for non-CAISO LSEs or other BAAs to satisfy their capacity or resource adequacy constructs.

However, the presence of spinning reserves does not change the fact that firm energy contracts without a specified source and a commitment to be available only to the CAISO generates the same double counting concern the CPUC expressed in disallowing internal LD contracts. In other words, non-specified resource adequacy imports are by nature not resource specific. Thus, without requirements to document the sources backing these imports to support RA showings and certify their dedication to the CAISO, such non-specified resources may not be backed by actual resources committed only to the CAISO, and may be relied upon by another balancing authority area or load-serving entity, especially during tight system conditions.

Moreover, SCE and Middle River Power have noted that WECC contingency reserve requirements have changed since Decision D.05-10-042 was adopted. A BAA's contingency (and, by extension, its spinning) reserve obligation is no longer determined by its type and amount of interchange, but it instead is determined by the greater of its most severe single contingency and the sum of three percent of (a) its load and (b) its internal generation. As a result, any reference to RA imports being backed by spinning reserves is no longer applicable as a WECC requirement. Therefore, any reliance that Decision D.05-10-042 may have placed on RA imports being backed by spinning reserves to support allowing firm liquidated damages RA import contracts to be RA eligible is now inconsequential given these changed

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[58] CPUC D.05-10-042, p. 101
[59] CPUC D.05-10-042, p. 68.

circumstances. The CPUC appears to have corrected this misunderstanding in its final RA track 1 decision.[60]

The Dependability of RA Import Capacity

Transmission delivery requirements for RA imports

The most robust and secure transmission delivery requirement for RA imports would be to require firm transmission service along the entire delivery path from the source to the CAISO balancing authority area sink. Other organized market regions generally have more stringent requirements than this. The following reflects the requirements on external capacity resources imposed in other ISOs and RTOs resource adequacy constructs:

- ISO-NE requires that in support of new import capacity resources, the customer must submit "documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load;"[61] Import capacity must document that neighboring and intervening control areas will afford the capacity the same curtailment priority as native load.[62] ISO-New England can get any and all information sufficient to show the ability of the generator to deliver capacity to ISO-New England.[63] External capacity must describe in detail how its capacity/energy will be delivered to the New England border and explain how such capacity/energy will be recognized by the control area with the same priority as native load.[64]
- MISO requires "demonstrating that there is firm transmission service from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability…;"[65] MISO also has external BAA qualification options to ensure energy schedules from external resources are interrupted in a manner that is transparent and supports reliability.[66] MISO has three categories: specific generator in external BAA;[67] slice of system;[68] and slice of system in a BAA that coordinates with MISO regarding planning reserve qualifications and emergency procedures.
- NYISO requires a demonstration, to the satisfaction of the NYISO, that the UCAP is deliverable to the New York Control Area.[69] NYISO also requires that in order to

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60 CPUC Track 1 Decision, D.20-06-028
61 ISO New England, Transmission, Markets and Services Tariff, Section 13.1.3.5.1
62 *Id.* at Section 13.2.3.5.3.1
63 Id. at Section13.1.1.2.7.
64 ISO New England Attachment M-Manual 20, Sections 12-13.
65 MISO Tariff, Module E, Sheet 69A.3.1.c
66 MISO Business Practice Manual 11, Section 4,2.5.
67 If MISO is in an emergency service will be interrupted only if the specific generator is on an outage.
68 Curtailment is pro-rata with load in external BAA if the external BAA is in emergency conditions.
69 NYISO MST - Market Administration and Control Area Services Tariff (MST), Section 5.12.2.1 and NYISO ICAP Manual, Section 4.9.3.2.

participate as external installed capacity suppliers, external resources must demonstrate that "if they demonstrate that the External Control Area will afford the NYCA Load the same curtailment priority that they afford their own Control Area Native Load Customers;"[70] for External Generators and External System Resources this means the external control area will not recall or curtail the capacity for purposes of satisfying its own RA needs.[71] In the case of control Area Resources, the Control Area will afford NYCA load the same pro rata curtailment priority afforded its own control Area load.[72]

- PJM imposes different requirements depending on how the external resource participates in the capacity market that can be either as rigorous as a pseudo-tie arrangement or as is required in most other areas, that the resource have firm transmission service to the PJM border.[73]
- SPP requires Firm Capacity to be supported firm service from external resource to load.[74] Firm Power must be supported by firm service and must be available in a manner comparable to power delivered to native load customers.

The CAISO desires reliable and dependable RA imports on par with native BAA resources, but the CAISO recognizes that load-serving entities are competing in a west-wide energy market where supply is shrinking. Requiring firm transmission service for RA imports from source to sink would provide the most secure and dependable RA import supply. Additionally, the CAISO recognizes there may be different degrees of firmness for firm point-to-point service based on the length the service is procured. For example, under the Pro Forma OATT, although short-term firm transmission rights owners have the right of first refusal, long-term firm transmission service rights would have a higher reservation priority if available transfer capability is insufficient to satisfy all requests and reservations. However, all long-term term point-to-point transmission service has an equal reservation priority with native load customers.[75]

The CAISO's preference is a source-to-sink firm transmission service requirement; however, the CAISO also is considering only requiring firm transmission service on the last line of interest to the CAISO BAA as an alternative. Some stakeholders have suggested this sufficiently provides reasonable assurance the RA import will be backed by sufficiently secure and reliable transmission service with minimal expected impact to market participant's ability to provide the import RA to the CAISO, while mitigating other concerns and providing other benefits. In the paragraphs immediately below, the CAISO discusses the differences between requiring firm transmission service from source to sink versus only requiring firm transmission service on the last line of interest to the CAISO BAA and the competing considerations associated with each.

Because firm transmission service can be scheduled up to twenty minutes before the start of the next scheduling interval (i.e., the operating hour), even if a non-firm transmission rights owner schedules in the day-ahead, the transmission provider can "bump" the non-firm rights holder if

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70 NYISO MST - Market Administration and Control Area Services Tariff (MST), Section 5.12.2.1
71 NYISO ICAP Manual, Section 4.9.1.
72 *Id.*
73 PJM Manual 18: PJM Capacity Market, Section 4.2.2
74 SPP Open Access Transmission Tariff, Attachment AA, Sections 7.3 and 7.5.
75 Pro Forma OATT at Section 13.2. BPA's Tariff has affords the same protection to firm transmission rights holders. BPA OATT at Section 13.6.

the firm rights holder submits their schedule prior to the operating hour or if needed to serve their native load. Stakeholders supporting a source to sink firm transmission requirement state that although there may be a reasonable degree of probability that a resource with non-firm service can support resource adequacy imports in many instances, these may not materialize when system conditions are strained and external entities are competing for the same transmission. They argue these deficiencies with non-firm rights potentially could render the transmission insufficient to support resource adequacy imports. However, these concerns are not present with firm transmission rights. Thus, the CAISO's preferred option would be to require full source to sink, point-to-point firm transmission service similar to other ISOs/RTOs.

Certain stakeholders have opposed requiring a firm source-to-sink transmission service, with some arguing that such a requirement affords less flexibility, is unnecessary, and more costly. They suggest firm service is generally more important in the constrained areas of the transmission grid, but is unnecessary elsewhere. For instance, BPA's system, which is a key concern and of interest to the CAISO, is like a funnel. The northern "network" is a broader, more robust, and non-radial network of transmission while the southern intertie portion funnels radially down to NOB and COB. It is this southern intertie portion of the BPA system that is more constrained and requires greater certainty and firmness to ensure deliverability to the CAISO BAA. Based on additional stakeholder feedback, the CAISO may be persuaded that firm transmission service only on the last line of interest is a prudent compromise, but subject to monitoring, potential additional protections discussed below, and the CAISO's ability to impose source to sink firm transmission service tariff requirements later if critical schedule cuts are occurring.

Based on the comments of some stakeholders and considering the competing concerns identified here, the CAISO is considering an additional or alternative framework whereby firm transmission service would only be required on the "last line of interest" to the CAISO boundary, *i.e.* the last leg. For example, on BPA's system, this represents BPA's southern interties terminating at COB and NOB. This compromise of requiring firm transmission service only on the last line of interest would allow the northern part of BPA's "network" to remain flexible and open. The CAISO anticipates that short-term, non-firm transmission service arrangements will still be possible on intervening lines of interest, while the CAISO gains a measure of RA import delivery security by requiring firm transmission service on the southern part of BPA's system, *i.e*. the last line of interest to the CAISO BAA. The CAISO will provide a list of these "last lines of interest" to the CAISO BAA from neighboring BAAs in the draft final proposal.

The CAISO seeks stakeholder comment on the issue of whether firm transmission service on the last line of interest to the CAISO BAA will ensure reliability and is feasible, or should the CAISO require point-to-point, source to sink firm transmission service as originally proposed. The CAISO requests stakeholders provide support to demonstrate that adopting a "last line of interest" only firm transmission service requirement would not unreasonably and adversely affect the dependability and reliability of RA imports. The CAISO also seeks stakeholder comment on other BAA's systems bordering the CAISO and whether such a "last line of interest" proposal is feasible and would effectively support RA import capacity dependability and deliverability.

The CAISO also is considering no longer requiring that firm transmission service be procured on a month-ahead basis so as not to constrain the market and restrict intra-month buying and selling opportunities. Instead, the CAISO proposes to allow firm transmission service to be procured up until the day-ahead market, where the firm transmission right is demonstrated via an e-Tagging requirement in the Day-ahead by no later than 3:00 PM pacific.[76] This less stringent transmission service requirement allows suppliers ample opportunity and flexibility to procure firm transmission service up until the day-ahead. It would be prudent though for suppliers to procure firm transmission service in advance to ensure delivery certainty and negotiate longer-term firm transmission service arrangements that may result in more favorable and cost-effective outcomes.

The CAISO is also considering a day-ahead e-tagging requirement for suppliers to provide a day-ahead transmission profile that demonstrates firm transmission on the last line of interest to the CAISO border. A day-ahead transmission profile e-tagging requirement would allow verification that firm transmission service has been secured by the supplier along the delivery path. The CAISO notes that more flexible approaches allowing required firm transmission service to be secured after the monthly showing timeframe may not guarantee that firm transmission service can always be secured for delivery. The CAISO will consider this impact and seeks stakeholder comments about whether a non-compliance penalty or other enforcement actions are necessary if delivery is not made under firm transmission service.

The CAISO also seeks stakeholder comment on how to convey the last line of interest. The CAISO suggests it is as the CAISO models the scheduling points in its full network model listed as the set of Intertie Constraints and Branch Groups listed in the table found by following the link in the footnote.[77]

Because the CAISO is considering an alternative approach where a firm transmission service requirement is only required on the last line of interest to the CAISO BAA, and since transmission on the other legs can be non-firm, which can jeopardize the entire schedule path, the CAISO seeks stakeholder input on additional requirements that may be appropriate or necessary to further ensure that suppliers' RA import capacity is dependable and delivered to the CAISO. In that regard, if the RA import supplier does not have firm service on the other intervening lines of interest between the source and sink, and the RA import is curtailed, the supplier may be unable to meet its RA obligations by delivering the required energy to the CAISO BAA.

One option to help prevent this is to impose a RA performance penalty on RA imports that fail to deliver their RA import quantity because they do not have firm service on the intervening lines of interest serving their RA import, which could result in a curtailment. Another alternative for

[76] The BPA OATT
[77] FNM Description doc, section 4- MAPPINGS OF ITC/BG, TNAME AND RELATED OPERATION PROCEDURES, at p. 13-16, found here: http://www.caiso.com/Documents/IntertieConstraintandBranchGroupInformation_Based_FNMReleaseDB2019Q1.pdf

consideration would be to require an RA import to submit a forced outage for the curtailment of an RA import due to non-firm transmission service, which would subject the resource to a potential UCAP reduction. Either of these options would incentivize (but not require) the RA importer to secure firm service from source to sink or risk the consequences of failing to deliver the RA import and be subject to a penalty or possible UCAP reduction. Any penalty would have to be robust enough to incent the delivery of the RA import to the CAISO border. The CAISO seeks comment regarding the scope, nature, and advisability of any such arrangement.

The CAISO also notes several ISOs/RTOs require that RA import capacity provided by a BAA from its pool of resources be afforded the same curtailment priority that is afforded the BAA's native load. Several ISOs and RTOs have this type of requirement. Some ISOs/RTOs require (1) RA imports supported by an external resource or portfolio of resources provide assurance that the external control area in which the resource is located will not recall or curtail the resource(s) for purpose of meeting its own resource adequacy needs or (2) RA imports document that the source BAA and intervening BAAs will afford the capacity supporting the RA import the same curtailment priority as its native load. The CAISO seeks to adopt similar types of requirements for RA imports to the CAISO to the extent practicable.

The CAISO seeks stakeholder comment regarding these aforementioned options and any other potential mechanisms that would best ensure RA imports are dependable and deliverable if the CAISO were to adopt, as an alternative, a "last line of interest" firm transmission service requirement.

Interim real-time bidding requirements for RA imports

Under current rules, RA imports are obligated to bid their full RA capacity into the real-time market for any hour in which they received any award from the day-ahead market. If they do not receive a day-ahead award for a given hour, then they are released from any further bidding obligation in the real-time market. In light of the CPUC Track 1 decision, and trying to balance market efficiency and liquidity, the CAISO proposes to extend the must offer obligation into the real-time market irrespective of the day-ahead market award for most RA imports. Currently, under the tariff, imports do not have any special rules in this regard. Only fast-start and medium-start generating units are obligated to bid their full RA capacity into the real-time market irrespective of their day-ahead award. System resources, by definition are not generating units under the tariff so they only are subject to the general rule. Pseudo-ties, however, are generating units. Therefore, short-start and medium-start pseudo-ties must bid their entire RA capacity into the real-time market today.

As an interim step, and until the CAISO implements the Day Ahead Market Enhancements initiative, RA imports will have a real-time must offer obligation as applicable to that RA import type. With implementation of the extended suite of day-ahead market products contemplated in that initiative, the CAISO expects all RA imports will then have only a day-ahead market must offer obligation. Real-time market bidding obligations will then depend solely on the day-ahead market award and will apply regardless of RA status.

As discussed above, with the addition of the forward requirement for source specification and the related attestation and supporting documentation that the supply will be dedicated only to the CAISO, the following CAISO-defined import types will qualify as resource-specific resource adequacy import resources: (1) Pseudo-Tie resources, (2) Dynamic Resource-Specific System Resources, and (3) Non-Dynamic Resource-Specific System Resources. The CAISO proposes that the first and second types of import would have the same real-time market must offer obligation during the pre-DAME period, with non-dynamic resource-specific imports holding a different obligation. The proposed obligations are described below:

1) Pseudo-Tie and Dynamic Resource-Specific System Resources

Pre-DAME Interim Period:

- Day-Ahead Market Must Offer Obligation.
    - Must offer full RA capacity into day-ahead market.
- Real-Time Market Must Offer Obligation.
    - Short-start and medium-start pseudo-tie and dynamic imports must bid their full RA capacity into the market regardless of the day-ahead award. All other pseudo-tie and dynamic imports must bid their full RA capacity into the real-time market for any hour in which they receive a day-ahead market award. This essentially matches the status quo.

Post-DAME:

- Day-Ahead Market Must Offer Obligation.
    - Must offer full RA capacity into day-ahead market.
- Real-Time Market Must Offer Obligation.
    - Must submit bid into the day-ahead market to the extent the resource has a day-ahead schedule for energy, ancillary services award, or imbalance reserves award.

2) Non-dynamic Resource Specific System Resources

Pre-DAME Interim Period:

- Day-Ahead Market Must Offer Obligation.
    - Must offer full RA capacity into the day-ahead market.
- Real-Time Market Must Offer Obligation.
    - Must offer full RA capacity into the real-time market regardless of day-ahead award.

Post-DAME:

- Day-Ahead Market Must Offer Obligation.
    - Must offer full RA capacity into day-ahead market.
- Real-Time Market Must Offer Obligation.

Must submit bid into the day-ahead market to the extent the resource has a day-ahead schedule for energy, ancillary services award, or imbalance reserves award.

4.1.7. Operationalizing Storage Resources

The CAISO has a small number of storage resources operating on the grid today, but that number will grow rapidly during the next few years, representing a growing share of the system's resource adequacy capacity. Storage resources are different from other resources in that they must first charge using energy from the grid to later discharge and provide energy back to the grid. The CAISO's current real-time market only looks ahead 65 minutes, but a charge and discharge cycle can take several hours. This timing discontinuity means that the real-time market does not allow sufficient lead-time to optimize the use of storage resources over full charge and discharge cycles.[78] Thus, being unable to charge a storage resource for anticipated future discharge needs can create reliability issues for the CAISO.

Since storage resources can qualify as resource adequacy resources, it is important that the CAISO can access and confidently rely on sustainable energy output from shown resource adequacy storage devices in the real-time market to ensure reliable operations. In this initiative, the CAISO proposes a framework that will give the CAISO this confidence. This framework includes using resource adequacy must offer obligations outlined in this paper, market power mitigation, combined with restrictions on state of charge managed through a new tool called the minimum charge requirement. [79]

Figure 9: Market rules for storage resources

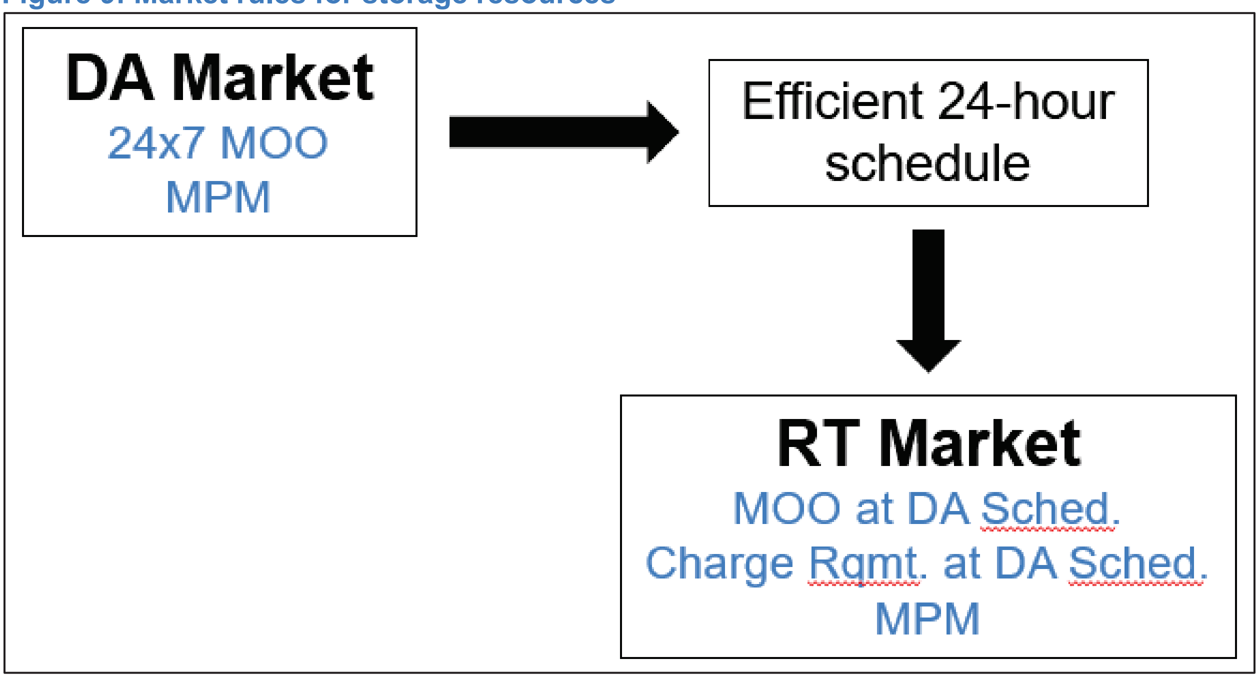


Figure 9 is a sketch of the rules that will apply to shown resource adequacy storage resources and how the CAISO will ensure that the storage resources are charged and available in the real-

[78] Nearly all of the storage resources in the fleet today are 4-hour duration batteries. This means that fully charged resources can discharge in 4-hours, and take just over 4 hours to charge due to round-trip efficiencies.
[79] Market power mitigation for storage resources is a proposal in the ESDER 4 initiative: http://www.caiso.com/StakeholderProcesses/Energy-storage-and-distributed-energy-resources.

time market for grid reliability. Like most resource adequacy resources, storage resources have a 24x7 must offer obligation in the day-ahead market. The resource adequacy program is designed to ensure that loads can always be met with the resource adequacy fleet in the day-ahead market. On peak summer days, this will likely include charging most of the resource adequacy storage fleet during the peak solar hours and discharging these resources during the evening hours during the evening ramp and net load peak. The day-ahead market optimizes over a 24 hour period, and will optimally schedule all resources on the grid to ensure a least cost solution to address market needs given market constraints. As described in this paper, the must offer obligation is a necessary feature so that the market software can derive a least cost solution given the bid-in resources available and load. For storage resources this includes bidding both the charging or discharging components of their resource, and not restricting CAISO from charging and discharging their battery (i.e. allowing the market software to freely adjust the state of charge based on submitted bids). The CAISO also ensures that the market solution is least-cost and includes measures that preclude resources, including storage resources, from exercising market power during intervals when they are marginal and could exercise market power.

The real-time market optimization is fundamentally different than the day-ahead market, primarily in that the real-time market only looks out 65 minutes in advance of the current interval versus the day-ahead market optimizing over 24 hour period. This could lead to a number of inconsistencies between the day-market and real-time market results when optimizing resources like batteries that have fuel availability constraints. For example, real-time prices during the lowest priced hours of the day may materialize at higher prices than in the day-ahead market and may result in storage resources not being charged. Another situation that could result in inconsistencies could be high prices prior to the peak net-load hours causing the real-time market to discharge the limited energy available from storage earlier than anticipated. These situations can occur on the CAISO system today given ramping needs spike as solar generation wanes toward sunset. These high prices could cause storage resources to be discharged prior to the peak net-load, when these resources are critical for the CAISO to meet system needs.

The solution to the day-ahead market results in charge and discharge schedules for storage resources and supply that meets load requirements over a 24-hour period. However, those day-ahead commitments are not immutable and can be adjusted and undone by the real-time market optimization, because the real-time market is sending dispatch instructions to resources based on prevailing market prices and resource bids and does not consider day-ahead schedules. To address this issue, the CAISO proposes that a minimum state of charge be observed in the real-time market, called a minimum charge requirement. This minimum charge requirement will set the minimum state of charge needed to preserve the amount of energy that the shown resource adequacy battery was scheduled to discharge in the day-ahead market solution. This will result in a storage resource shown for resource adequacy to always have state of charge to achieve the day-ahead discharge schedule. This will aid grid reliability because day-ahead schedules may have storage online and charged to meet load that must be served by storage resources. This is an essential resource adequacy market enhancement that will allow the CAISO to operate the system reliably with a fast growing fleet of use and energy-limited resource adequacy qualifying storage devices.

In the future, the CAISO may look at other market enhancements to address this concern and allow for additional real-time market participation flexibility, noting that shown resource adequacy battery storage devices will still have flexibility under this proposal to re-bid in real-time any capacity not already committed in the day-ahead market.

Stakeholder Feedback

Some stakeholders raised concerns about the minimum charge requirement (MCR) tool and presented other potential options to address this reliability need in the real-time market. One alternate proposal would be to extend the look ahead in the real-time market to include the net-load period and other periods when storage resources are critical for grid reliability. Another would be to develop a tool similar to short-term unit commitment (STUC) to look ahead and assign minimum state of charge values to storage resources based on expected needs. Today, the real-time market solutions are time and computationally intensive, and forecast accuracy degrades over longer time horizons, jeopardizing the operational integrity and dispatch efficiency of the real-time market. Thus, this solution is technically and operationally infeasible at this time, but the CAISO will continue to consider how greater flexibility can be provided in the real-time market in the future as technology and forecasting techniques progress. CAISO also acknowledges that a tool in the real-time market, similar to the short term unit commitment tool, could also be used to set minimum charge requirements. These minimum requirements may be a better basis for decision making and could be done regularly throughout the day with more accurate load and renewable forecast data available. Although this technology may seem similar to existing tools the CAISO has, it would still need to look out several hours to view the entire evening peak, and would need to interface with nearly all of the real-time market systems. Implementing such a feature is non-trivial, but the CAISO may consider such tools and methods in the future.

Finally, stakeholders also requested that the CAISO develop a tool more similar to an exceptional dispatch tool, which would only dispatch storage resources to charge during critical periods when it was absolutely essential. Certain stakeholders advocated for this approach as it would have less impact than the proposed minimum charge requirement for each individual resource throughout the day. Such an approach may be possible to manage storage resources and ensure the grid is situated to meet evening peak net-load periods, however there are several challenges to implementing an exceptional dispatch solution. First, like the solution discussed previously, this would also require that either the real-time market or a tool running in parallel with the real-time market be developed with the capability to look out and forecast with accuracy several hours in advance. This tool would likely have to have at least an eight hour look ahead function to include the full evening peak, particularly any hours when net load exceeds traditional generation, plus additional hours to allow time to charge a battery prior to the peak and the critical ramping period when additional generation is available. Finally, such a tool would need to be run each 5-minute interval, so that the real-time market does not ‘undo’ the instructions sent to the storage resources from this new tool. Development of a tool like this would be difficult and computationally burdensome, and possibly as computationally burdensome as expanding the real-time market look out horizon. This tool could also significantly increase bid cost recovery, as storage resources would generally be procured in the most expensive periods at times when they could be far out of the money. Possibly the most serious concern is around reliability. In the event that this tool does not perform perfectly, it may allow a situation where CAISO is unable to serve load because a battery cannot be charged sufficiently prior to periods of need. Furthermore, running a market with frequent exceptional dispatch is not preferable and inefficient, which may occur during tight ramp or system conditions.

A further discussion of other methodologies considered as well as examples of operational concern for storage resources was provided in the previous version of this proposal.

Minimum Charge Requirement

The minimum charge requirement tool would operate in the real-time market and would set a required state of charge such that each resource adequacy storage resource would have a minimum state of charge set at its cleared day-ahead schedule.

This requirement will consider charging and discharging schedules set in the day-ahead market. For example, a resource with a 180 MWh discharge schedule in the evening and a 50 MWh charge schedule in the afternoon, would have a minimum charge requirement set at 130 MWh in the morning prior to the charging schedule, and a 180 MWh minimum charge requirement between the charging and discharging schedules.

Generally, there will be no minimum state of charge during times of the day after the hour when the resource receives its final awards in the day-ahead market. Resources may bid in a way to ensure additional flexibility and availability in the real-time markets. Resources with greater aggregate discharge schedules may have greater minimum charge requirements, which may bind more frequently than those with lower requirements. Two detailed examples of how these requirements would work are outlined below. Both examples include resource similar to the hypothetical resource discussed in the example above.

Example 1:

Suppose a 50 MW storage resource with 200 MWh of storage capability is dispatched to charge zero MWh during the lowest priced hours in the morning in the day-ahead market, and is scheduled to discharge a total of 180 MWh in the evening. The ISO minimum charge requirement will require that the resource be charged sufficiently to meet the evening schedule so that it can discharge the full 180 MWh. Because the day-ahead schedule to discharge does not start until hour ending 19, the resource is required to maintain a 180 MWh state of charge until this time. After that time, the minimum charge requirement begins to decrease.

In this example, suppose there is a real-time sustained price spike at $1,000/MWh for energy in hour ending 17, perhaps during the peak ramping period. Ideally, the resource would like to dispatch up to the full 50 MW of capability to capture these high prices, but it is prevented from doing so and limited to only 20 MW because of the minimum charge requirement.[80] This is illustrated by the numbers in the red boxes in Table 14, below.

In the later hours of the day, the minimum charge requirement decreases with the day-ahead schedule. If the resource is not scheduled to discharge as much energy in real-time as was scheduled in the day-ahead market, the resource will have an actual state of charge that exceeds the requirement. This is illustrated by the numbers in the green boxes in Table 14 below.

Table 14: Minimum charge requirement example 1

Hour	9	10	11	12	...	17	18	19	20	21	22	23	24
Load	190 MW	190	190	200	...	300	330	335	345	350	340	280	210
DA Bid ↓	$30/MWh	$30	$30	$30		$30	$30	$30	$30	$30	$30	$30	$30
DA Bid ↑	$60/MWh	$60	$60	$60		$60	$60	$60	$60	$60	$60	$60	$60
DA Price	$50/MWh	$50	$50	$50		$60	$60	$80	$80	$100	$100	$80	$70
DA Sched	0	0	0	0		0	0	20	30	50	50	30	0
DA SOC	200 MWh	200	200	200		200	200	180	150	100	50	20	0
RT Bid ↓	$50/MWh	$50	$50	$50		$50	$50	$50	$50	$50	$50	$50	$50
RT Bid ↑	$100/MWh	$100	$100	$100		$100	$100	$100	$100	$100	$100	$100	$100
RT Price	$60/MWh	$60	$60	$60		$1,000	$60	$100	$100	$100	$100	$100	$70
RT Sched	0 MW	0	0	0		20	0	20	30	40	50	30	0
RT SOC	200 MW	200	200	200		180	180	160	130	90	40	10	0
Min Chrg	180 MW	180	180	180		180	180	160	130	80	30	0	0

- Note that in this example, the minimum charge requirement does not necessarily match the scheduled state of charge in the day-ahead market.

[80] In reality, the 5-minute market would dispatch the resource at the full 50 MW Pmax until the state of charge was equal to the 180 MWh minimum charge requirement. After this point the dispatch resulting from bids would be overridden with a dispatch instruction (zero MW) respecting the minimum charge requirement. All of these examples use hourly time blocks for simplicity.

Example 2:

Suppose the same 50 MW storage resource with 200 MWh of storage capability, is dispatched to charge 50 MWh during the lowest priced hours in the morning in the day-ahead market, and is scheduled to discharge 80 MWh in the evening. In this case, the ISO minimum charge requirement will require that the resource be charged sufficiently to meet the evening schedule inclusive of the day-ahead morning schedule. Because the day-ahead schedule to discharge does not start until hour ending 19, the resource is required to maintain an 80 MWh state of charge between hour ending 11 and hour ending 19. However, prior to hour ending 11, the resource has a lower minimum charge requirement because of day-ahead schedule to charge 50 MW at that time. The start of the day requires a minimum charge value equal to the state of charge at the beginning of day in the day-ahead market. In the evening, after the scheduled discharge in the day-ahead market, the minimum charge requirement decreases to zero MWh.

This example illustrates that it is possible for a resource to charge in the morning prior to the interval that scheduled for charge in the day-ahead market. This may occur when prices are lower than expected and lower than real-time market bids. This occurs in the example in hour ending 10 where prices are $25/MWh and the resource has a bid to charge at prices at or below $25/MWh. In this hour, the resource is scheduled to charge at 30 MW, which increases the state of charge to 60 MWh, above the 30 MWh requirement. The numbers in the green boxes in Table 15: illustrate this below.

This example also illustrates that in hour ending 11, the resource does not have the required 80 MWh of energy stored and is therefore compelled to charge, with an energy schedule of 20 MW, to bring the total state of charge up to the requirement. The numbers in the red boxes in Table 15: illustrate this below.

Prior to the period when the resource was scheduled to discharge in the day-ahead market, periods with particularly high prices may develop. However, if the resource is not charged above the minimum charge requirement the resource may not respond to these high prices. In this example, prices spike to $200/MWh in hour ending 18, however the hypothetical storage resource is unable to respond these signals because of the minimum charge requirements, ensuring that later day-ahead schedules can be delivered. In hour ending 18, the resource has a requirement for 80 MWh state of charge and has a state of charge of exactly 80 MWh. The numbers in the orange boxes in Table 15 illustrate this below.

Table 15: Minimum charge requirement example 2

Hour	9	10	11	12	...	17	18	19	20	21	22	23	24
Load	190 MW	190	190	200	...	300	330	335	345	350	340	280	210
DA Bid ↓	$30/MWh	$30	$30	$30		$30	$30	$30	$30	$30	$30	$30	$30
DA Bid ↑	$60/MWh	$60	$60	$60		$60	$60	$60	$60	$60	$60	$60	$60
DA Price	$50/MWh	$50	$25	$50		$60	$60	$60	$70	$70	$60	$60	$60
DA Sched	0	0	-50	0		0	0	0	30	50	0	0	0
DA SOC	30 MWh	30	80	80		80	80	80	50	0	0	0	0
RT Bid ↓	$25/MWh	$25	$25	$25		$25	$25	$25	$25	$25	$25	$25	$25
RT Bid ↑	$70/MWh	$70	$70	$70		$70	$70	$70	$70	$70	$70	$70	$70
RT Price	$60/MWh	$25	$60	$60		$60	$200	$60	$60	$60	$60	$60	$60
RT Sched	0 MW	-30	-20	0		0	0	0	0	0	0	0	0
RT SOC	30 MW	60	80	80		80	80	80	80	80	80	80	80
Min Chrg	30 MW	30	80	80		80	80	80	50	0	0	0	0

- Note that in this example, real-time prices remain low in the evening and the resource does not receive a market instruction to discharge.

It is important for resource owners to understand how the minimum charge requirement will work for bidding into the real-time market and state of charge management. This tool will only stipulate a minimum state of charge that a resource needs to maintain based on day-ahead market schedules. These minimums will be determined at the conclusion of the day-ahead market run and will be known to scheduling coordinators in advance of the real-time market. Knowing these minimums and how actual state of charge values develop in the real-time market may encourage resource operators to adapt bids in the real-time market to increase state of charge for resources so that they have more availability to respond to unexpected high real-time market prices.

5-minute charge requirements

The examples outlined above all include hourly charge requirements and hourly dispatch instructions. The actual real-time market is broken into 5-minute intervals. The charge requirements will be smoothed over the hour, so they are achievable within 5-minute dispatch instructions. For example, if the minimum charge requirement is zero MWh in the prior hour and 12 MWh for the current hour, then the minimum charge requirement for the first five minute interval would be one MWh, then two MWh for the second interval, increasing by one MWh with each successive interval and ending with a requirement of 12 MWh for the final 5-minute interval.

RA Implications

As discussed above, storage resources providing RA capacity will be subject to a must offer obligation that includes charge, discharge and energy bids. When storage resources do not make these available to the CAISO, because of outages or limits set by bid parameters, the RA capacity value for the resource is reduced in the UCAP process. However, if CAISO is maintaining a state of charge for these resources through the minimum charge requirement, there will be no reduction in the RA capacity values.

4.2. Flexible Resource Adequacy

The CAISO seeks to close certain gaps in the existing flexible RA construct through a new flexible RA framework that more deliberately captures the CAISO's operational needs and the predictability (or unpredictability) of ramping needs. Changes to the flexible capacity product and flexible capacity needs determination must closely align with CAISO's actual operational needs for various market runs (*i.e.*, day-ahead market and fifteen-minute market). The CAISO must ensure the flexible RA proposal mirrors the needs identified in the Day-Ahead Market Enhancements Proposal. However, at this time, the Day-Ahead Market Enhancements Proposal requires additional development before the CAISO is able to further advance its flexible RA capacity proposal. Therefore, the CAISO is deferring significant modifications to its flexible RA capacity proposal for this straw proposal.[81]

4.3. Local Resource Adequacy

In previous proposals, the CAISO developed proposals for Local Assessments with Availability Limited Resources and Meeting Local Needs with Slow Demand Response. These proposals have been separated out from this document and finalized in a separate Draft Final Proposal.[82] A discussion of how to potentially apply UCAP counting to local RA is also now included in this section.

4.3.1. UCAP in Local RA Studies

The CAISO will continue running the local capacity studies exactly as is done today using NQC values and will publish the local capacity requirements in terms of NQC. At the beginning of the CAISO's local capacity study report, the CAISO will include a translation table from NQC to UCAP at the level of LSE compliance requirement. The translations will be done by TAC, as required by the CAISO Tariff. For each TAC, the total local UCAP requirement will be defined as follows:

$$\textit{Total TAC UCAP responsibility} =$$

$$\left(\sum \textit{of TAC wide NQC requirements}\right) \times \left[\frac{\sum \textit{ of TAC wide UCAP values}}{\sum \textit{ of TAC wide NQC values}}\right]$$

[81] For the CAISO's most recent proposal, please refer the Third Revised Straw Proposal, pp. 68-77. Available at http://www.caiso.com/InitiativeDocuments/ThirdRevisedStrawProposal-ResourceAdequacyEnhancements.pdf.

[82] The Draft Final Proposal on these items is available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx.

The CAISO's local capacity study report is done by May 1 and local requirements are sent out in July before the NQC/UCAP list for the next compliance year is available (September). Therefore, the NQC and UCAP *values* used in the second term (*i.e.* the conversion factor) are given by all available values in the previous year's NQC/UCAP list for resources already in-service. This is necessary to avoid complications derived from including estimated NQC and estimated UCAP values for new resources that may or may not become in-service between the time when the report is written and the compliance year.

The CAISO believes using the NQC and UCAP values from the current year is both an infeasible and undesirable result. The LCR base cases are built in December-January and studies are run in February. The stakeholder process runs through May 1.[83] The annual NQC deliverability study is done in June-July timeframe and, per CAISO Tariff and BPM, LCR allocations are released mid-July. The NQC list is currently completed in August (sometimes early September). Therefore, it is not possible to utilize actual NQC and UCAP values for the LCR studies.

Because the annual LCR studies begin in December before the year of need, they are run with the previous year's NQC. Given the timing of the studies, this is necessary even though those values will not be the actual NQC values used in RA showing made in the subsequent October or later. Similarly, given that NQC values already come from previous years and given the limited year-by-year changes in new resources and potential for TAC-wide available total UCAP, waiting for the new UCAP is not needed.

The CAISO will calculate LSEs' local load-share ratio responsibility in terms of UCAP at the TAC level. As is done today, LRAs will be given their share UCAP to allocate to their LSEs. The LRA may allocate these responsibilities using its preferred methodology, however, as specified in 40.3.2 (c) of the CAISO Tariff, if the LRA does not allocate their entire responsibility to their jurisdictional LSEs the CAISO will allocate the difference.

LSEs' individual compliance in meeting their given local allocation is calculated in UCAP[84] (for compliance with ISO Tariff sections 43A.8.1 and 43A.8.2). In other words, an LSE will be determined to be individually adequate if its shown UCAP is greater than its allocated share. As all RA showings will be made in terms of UCAP, the CAISO will convert UCAP values back into NQC values and run its compliance studies of all RA showings with local technical criteria and requirements using NQC values, as done today. In addition to deficiencies caused by effectiveness factors that exist today, the CAISO must also ensure there are adequate MWs in a given area. For example, the CAISO may receive adequate UCAP to meet individual obligations, but not enough MW to serve peak load in a local capacity area. Therefore, collective deficiencies will be defined as both insufficient MW of NQC to meet the LCR as well as the existing insufficiently effective capacity.

[83] Per Tariff section 40.3.1 (and RR BPM) LCT study (including the new UCAP translation) needs to be final by May 30 – 120 days before the showings get here. CPUC requires us to file draft LCR study by around April 1 and final by May 1.
[84] This is consistent with existing ISO Tariff sections 43A.8.1 and 43A.8.2.

The CAISO will notify LSEs of any deficiencies and provide them an opportunity to cure. If still short, the CAISO may purchase capacity from remaining non-RA resources through its CPM authority cure the deficiency. The cost will first go pro rata to each SC for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area (all calculated in UCAP – per 43A.8.1) and second if anything else is required the cost allocation will be based on the SCs proportionate share of Load in such TAC Area(s) as determined in accordance with Section 40.3.2 – per 43A.8.3.

In assessing which resources to offer CPM designations to cure deficiencies, the CAISO may continue to assess a number of variables from the available resources, including but not limited to cost, effectiveness, and reliability as dictated by ISO Tariff section 43A.4.2. The CPM cost will be divided to the LSEs per the different varieties of CPM as required by the CAISO Tariff. The LSEs that receive cost allocation for the CPM will get a capacity credit commensurate with their CPM cost ratio allocation. The amount of the credit is based on the quantity of UCAP purchased, not the NQC value.[85]

4.4. Backstop Capacity Procurement Provisions

In this initiative the CAISO is: (1) proposing new authority to make CPM designations, (2) flagging potential changes to the RMR performance mechanism if changes to RAAIM are considered, and (3) proposing a new tool to encourage load to procure resources up to full UCAP requirements and discourage load serving entities from leaning on capacity procured by other entities.

The CAISO proposes new CPM authority to procure resources in the following three scenarios: (1) system UCAP deficiencies through the RA process; (2) inability to serve load in the portfolio deficiency test; and (3) an identified need to procure local RA after an area or sub-area fails to meet the energy sufficiency test. These three needs are proposed extensions of the existing CPM authority.

This proposal includes a new tool called the UCAP deficiency tool, which incentivizes entities to show at or above their UCAP requirements and will discourage leaning between entities during the RA showings. This tool will assess charges against entities that show UCAP below their requirements and allocate these payments to entities that show above their requirements.

4.4.1. Stakeholder Comments

Overall, stakeholder comments on the 4th revised straw proposal were generally supportive of extending CPM authority for 1) system UCAP deficiencies; 2) inability to serve load in portfolio deficiency test; 3) local RA after area or sub-area fails to meet the energy sufficiency test. Capacity Procurement Mechanism Modifications. While some stakeholders like Middle River Power, were unsupportive of the move towards a UCAP counting methodology for RA credit,

[85] In other words depending of the situation they may get one-for-one cost/credit allocation, sometimes it may not be one-for-one cost/credit allocation, at worst it could be as low as no credit if the resource has no qualifying UCAP value.

they understood the need to extend CPM authority to cure system UCAP deficiencies. Others, like PG&E and SDG&E, wanted additional clarification on how the portfolio sufficiency test would result in a CPM designation, and how the CAISO would know that the resources it procured would address these deficiencies given that there wouldn't be time to re-run the portfolio analysis. SDG&E also questioned the need to retain CPM authority for both NQC and UCAP system deficiencies. Given the general support from stakeholders, the CAISO's backstop proposal remains largely unchanged.

4.4.2. Capacity Procurement Mechanism Modifications

The CAISO uses CPM to backstop the RA program. Specifically, when there is insufficient capacity shown in the RA process to reliably operate the grid, the CAISO may make CPM designations to procure resources that have not been shown in the RA process so that sufficient capacity is available to reliably operate the system. RA is shown on a year-ahead and a month-ahead basis, and CPM can be used to backstop in either timeframe or in a more granular timeframe. Resource owners with additional non-RA capacity can participate in the competitive solicitation process (CSP) for their bids to be considered if and when the CAISO makes a CPM designation. Generally, in any timeframe the CAISO makes a designation, the CAISO considers all options for procurement and selects the least cost option that meets the reliability need is selected. Additionally, when the CAISO makes any CPM designation, it posts information about the designation and supporting documentation outlining why the CAISO needs the resource.

Authority to make CPM designations for capacity currently includes the following designation types:

1. System annual/monthly deficiency – Addresses insufficient system RA capacity in year-ahead or month-ahead RA showings
2. Local annual/monthly deficiency – Addresses insufficient local RA capacity in year-ahead or month-ahead RA showings for one specific entity making showings
3. Local collective deficiency – Addresses insufficient local RA capacity in year-ahead RA showings to meet the reliability needs for one specific local area
4. Cumulative flexible annual/monthly deficiency – Addresses insufficient flexible RA capacity in the year-ahead or month-ahead showings for system needs
5. A "Significant Event" occurs on the grid
6. CAISO "Exceptional Dispatches" non-RA capacity

The CAISO proposes modifying its existing CPM authority to procure additional capacity in the following scenarios: (1) system UCAP deficiencies through the RA process; (2) inability to serve load in the portfolio analysis test; and (3) an identified need to procure local RA after a local area or sub-area fails to meet the energy sufficiency test.

The CAISO will seek additional CPM authority to procure capacity based on system UCAP deficiencies. The CAISO will not make these designations merely because some LSEs are deficient, but instead will only make such designations when there are overall deficiencies based on all RA showings. To make these designations, the CAISO will compare all UCAP reflected in RA showings to the total requirements for UCAP, and may make additional designations based on that difference. This authority will be similar to the CAISO's existing authority to procure for system deficiencies, which are based on total shown NQC values. This new authority will be based on shown UCAP and will apply in the year-ahead and month-ahead timeframes. Similar to existing authority, CAISO will alert entities with shortfalls and provide those entities with a chance to cure any shortfall. CAISO backstop procurement will only occur after this cure period closes and deficiencies remain.

The CAISO is not seeking authority to procure additional backstop capacity merely because an individual entity shows less capacity than its requirement. CAISO procurement based on individual LSE shortfalls could result in the CAISO procuring more capacity than is necessary if other LSEs happen to show more capacity than they are required. By procuring only for system UCAP shortfalls, the CAISO will ensure it receives enough UCAP to reliably operate the grid. This approach is consistent with other categories of CPM procurement authority, where the CAISO only procures if there is a cumulative deficiency. However, procurement in this manner could result in entities "leaning" on other entities that show capacity in excess of their individual UCAP requirement. Because of these incentives, the CAISO also proposes to implement a UCAP incentive mechanism, discussed further below.

Section 4.1.3, above, provides details about the portfolio analysis the CAISO will conduct to determine if the resources procured through the RA process will be sufficient to meet the energy and peak capacity needs over the entire month. If the CAISO determines it is unable to meet these needs through this analysis, it can designate additional capacity using the CPM tool to pass the analysis. The CAISO will use this procurement authority at the same time it undertakes month-ahead designations for other CPM backstop designations. If the CAISO identifies a reliability concern through the portfolio analysis, it will continue to allow entities to first cure the identified deficiency before the CAISO makes any backstop designations.

Finally, the CAISO proposes additional backstop authority to ensure that procured local resources can meet energy needs in each local area and sub-area during the upcoming year. If CAISO identifies any capacity and/or energy shortfall, it will provide a cure period for entities to clear any deficiencies before exercising its backstop procurement authority.

Example: UCAP Deficiency

The CAISO provides the following brief example to explain a scenario where it could make a potential CPM designation for deficient UCAP procured in the RA process, after the cure period.

Assume in this example that there are three load serving entities, each with a requirement to show 100 MW of UCAP. The first entity shows 125 MW, or 25 MW above the requirement, while the second and third entities show 80 MW and 75 MW respectively, or 20 MW and 25 MW below requirements, respectively. In aggregate, at the system level the RA process procures 280 MW and does not meet the 300 MW requirement for UCAP. This indicates a 20 MW shortfall at the system level, for which CAISO could undertake backstop procurement. If CAISO procures backstop capacity, it will allocate costs for that backstop to the entities that were deficient, in this case entities 2 and 3, per the LSE's share of the overall deficiency. In this case, entity 2 will be assigned 44% (20/45) of the costs and entity 3 will be assigned 56% (25/45) of the costs to procure the additional capacity for this designation. The CAISO provides additional discussion, below, about how LSE 1's showing can result in incentive payments for its 25 MW of excess capacity.

Figure 10: UCAP Deficiency CPM Backstop

LSE	Req. (MW)	Shown (MW)	Shortage (MW)
1	100	125	
2	100	80	20
3	100	75	25
TOTAL	300	280	45

Cost Allocation
20/45
25/45

BACKSTOP: 20 MW

CPM Designation Order

Today, if the CAISO makes multiple CPM designations for any single planning horizon, it first allocates costs and credits to individual entities that are deficient in their RA showings, then to all applicable LSEs for the residual collective deficiency. The CAISO will maintain the similar paradigm with the new authority. Going forward, the CAISO will first allocate the costs to system UCAP deficiencies, then to NQC system deficiencies, then to local individual deficiencies, then to local collective deficiencies, and finally to portfolio deficiencies. This order is illustrated in Figure 11 below. As with current practice, if the CAISO considered multiple designations in one timeframe, it would make designations that meet all of the necessary reliability needs at the least cost. This figure may be used to determine cost and credit allocation, if the CAISO makes multiple CPM designations using different CPM authority.

Figure 11: CPM Designation Order

- **System UCAP deficiencies**
- **System NQC deficiencies**
- **Local individual deficiencies**
- **Local collective deficiencies**
- **Portfolio analysis deficiencies**

4.4.3. Making UCAP Designations

Today, the CAISO uses net qualifying capacity as the basis for determining all designations for all CPM procurements. These quantities are used to determine the total capacity cost for the designations (Quantity x CSP price) and the total amount of credit that is allocated to load serving entities who incur these costs. With the proposed additions to the CPM authority discussion in the section above, the CAISO may procure for a specific MW quantity of UCAP, rather than NQC. The CAISO is not planning to change pricing rules, the soft offer cap or bidding rules under the existing CPM tool.

Each resource will have a UCAP and NQC value that is stored in CAISO databases used for resource adequacy calculations. These values can be used to inform a ratio, or conversion factor, between UCAP and NQC. With this ratio, a specific price can be determined for any quantity of UCAP designation, similar to any NQC designation. This may imply that a designation for UCAP may be awarded to a resource with a higher bid price, but better conversion factor.

An example of the UCAP counting is outlined in Table 16. This table shows two hypothetical resources, resource 1 and resource 2. In this example resource 1 has an NQC value of 200 MW with an accompanying UCAP value of 100 MW, and resource 2 has an NQC value of 150 MW and a UCAP value of 125 MW. Resource 1, bids into the competitive solicitation process for CPM at $5/MW, while resource 2 bids at $6/MW. If the CAISO makes a designation for NQC needs for a local deficiency it will first select capacity from resource 1 because the bid prices are less expensive for resource 2. However, if the CAISO is making a designation for UCAP, capacity from resource 2 will be selected first, as the effective bid prices for resource 2 are less expensive. In this example, the effective price for UCAP capacity for the resource 1 is $10/MW, while the price is $7.20/MW for resource 2.

Table 16: UCAP CPM price example

	NQC	UCAP	UCAP:NQC	Bid ($/MW NQC)	Effective UCAP Bid ($/MW UCAP)
Resource 1	200	100	0.5	$5	$10
Resource 2	150	125	0.8	$6	$7.20

4.4.4. Reliability Must-Run Modifications

This proposal includes removing the RAAIM tool from CAISO processes and tariff provisions. RAAIM incentivizes those RA resources that bid shown RA capacity into the market during the availability assessment hours, and charges those RA resources that do not. The CAISO believes the RMR provisions already provide sufficient incentive for RMR resources to be available and perform. The CAISO is also proposing a new penalty structure for RMR resources, which would assess performance penalties if the resource was not available above some pre-determined threshold.

An appropriate penalty structure for RMR resources may be one similar to the existing RAAIM tool. The RAAIM penalty has predetermined thresholds for performance, with performance below 94.5% penalized and performance above 98.5% incentivized during any specific month. Through this initiative, the ISO is considering 1) if incentive payments are appropriate for RMR resources, 2) changing the penalty parameter and availability thresholds that RMR resources are subject to, and 3) how incentive penalties should be distributed.

It may not be appropriate for RMR resources to receive a performance incentive payment similar to resources that are exposed to the RAAIM. RMR resources are individually contracted and include specific terms of service. It may not be appropriate for the agreement to include payments for higher performance, as the performance and needs of the system should already be internalized and expected in the contract. There is also a question about how additional incentive payments would be funded and if they would come from the same group of load serving entities that are already paying for the RMR designation, or from a different pool.

An appropriate performance threshold might not be 94.5% for RMR resources as it is for RAAIM. Since each RMR contract is tailored to the specific resource, it may make sense that performance targets are customized based on the past performance of the particular RMR resource. For example, a RMR resource may have a recent historic availability of 98% while another's is 85%. It seems appropriate to apply a higher performance threshold to the former resource than the latter.

Further, targets could be designed to vary with different seasons. This may be appropriate where critical need for a resource is during a particular time of year. Similar to the RAAIM penalty, the CAISO could calculate the availability on a monthly basis and assess penalties on those amounts. Unlike RAAIM, this tool might not be self-funding given the limited number of RMR units, and any collected penalties could be returned to the parties assessed costs for the RMR designation.

The CAISO may continue to use the CPM soft offer cap as the penalty price for poor performance for the RMR incentive tool, but may also elect to use a penalty price set at the RMR price. Using the CPM soft offer cap would be consistent with historic penalty rates assessed for resources, and using a rate equal to the rate of the specific RMR contract might set a price more appropriate for the specific resource receiving the RMR designation. The CAISO continues to seek stakeholder feedback on an appropriate availability incentive design to apply to RMR resources after the removal of the RAAIM tool.

4.4.5. UCAP Deficiency Tool

As noted above, the CAISO is not proposing new CPM authority to make a designation when a specific entity shows less UCAP than individual requirements as long as the system as a whole is adequate. However, the CAISO is proposing a new tool, called the UCAP deficiency tool, which will impose deficiency charges on entities with deficient UCAP showings. This tool is designed to prevent leaning and to incentivize entities to show above their individual UCAP requirements. Further, the CAISO notes that deficiency charges are not a novel idea. Other ISOs and RTOs impose similar deficiency charges on LSEs that fail to procure sufficient resource adequacy capacity. For example, MISO charges LSEs a Capacity Deficiency Charge if they elect not to procure all or a portion of their PRMR from auction or bilateral contracts. The Capacity Deficiency charge is the amount of deficient MWs multiplied by 2.748 times the Cost of

New Entry. This charge is then distributed on a pro rata basis to other LSEs who did not opt to pay the charge.[86]

The concept of the UCAP deficiency tool is to apply a charge to resources that show less than their UCAP requirement, and distribute those collected charges to resources showing above their requirements. Without this tool, one or more entities could choose to not procure their full UCAP requirement because they suspect that showings at the system level system will be sufficient to meet aggregate requirements or that the ISO will not make a backstop designation and no additional costs will be allocated. This constitutes leaning.

Ideally, the rules for a UCAP deficiency tool would result in a streamlined and straightforward mechanism where any entity that shows less than their requirements would be charged for the amount of capacity the entity is short. This proposal includes specifications that the deficiency price will be set at the CPM competitive solicitation soft offer cap, which is currently $6.31/kW-month. All revenue collected will be distributed to entities that show above their UCAP, in proportion to the total amount shown above requirements for all entities.

Several stakeholders continue to object to the UCAP deficiency tool. Some stakeholders argued that the UCAP deficiency tool could be duplicative of other penalties and charges, and could further distort the bilateral RA market. The issue presented is a cost causation problem and should be addressed with a uniform approach for all capacity shown across all local regulatory authorities. Under the current construct showing less capacity than required, or leaning, increases the risk of a potentially costly CPM designation. When CAISO makes CPM designations they are done strictly for reliability and may not be preferred resources for load serving entities, and they may not consider other resources that were not shown to the CAISO. This proposed tool should help reduce CPM by applying an incentive structure for all load serving entities to show capacity up to their requirements.

Some stakeholders argue that the charges related to the proposed UCAP deficiency tool would be duplicative of the charges that could come from CPM designations. The deficiency tool is designed specifically to avoid that outcome. If an individual load serving entity is charged for capacity procured through the CPM tool that capacity is credited to the entity and will not be used for charges applied through the UCAP deficiency tool. **In other words, the CAISO will not procure CPM and impose a UCAP deficiency charge for the same MW of deficiency**. This is illustrated further in the examples below.

Stakeholders further commented that the UCAP deficiency tool may compel resources to withhold capacity. This seems unlikely. If load serving entities are struggling to contract for capacity, it is likely that they are unwilling to pay a price close to the soft offer cap to procure that capacity. Load serving entities that have excess capacity would likely desire to sell that excess capacity, for revenue certainty, rather than wait for a chance to split an unknown quantity of penalty payments. These UCAP incentive payments are distributed to any entity that is showing surplus supply. If there are multiple entities showing additional capacity, then each of those entities will only get a fraction of the incentive payment for the capacity that is short. Additionally, the deficient LSE would be guaranteed to pay the soft over cap, so entering into a

[86] See MISOs Resource Adequacy Business Practice Manual BPM-011-r23 page 105

contract at some fraction would be more economically rational than choosing to pay the penalty. This is also illustrated in the examples below. In the examples below, there is are financial trades between load serving entities that could take place such that the deficient load serving entity would pay less than the penalty and the LSE with surplus would be able to make more from the trade than it would from the incentive payment from the UCAP deficiency tool. This implies that the tool could be effective at incentivizing trades between load serving entities for capacity and getting those trades shown to meet resource adequacy requirements to ensure reliable grid operation.

The examples below include several scenarios that step through the details for how the UCAP deficiency tool could work in practice.

Example: UCAP Deficiency Tool, with no CAISO backstop

This set of examples presents three scenarios where CAISO would use the UCAP deficiency tool, but not make any CPM designation. The first scenario shows procurement above the UCAP requirements and therefore no CPM designation.

- In this example LSEs 1 and 2 show 10 MW and 15 MW above their 100 MW month-ahead requirements, respectively, and entity 3 shows 10 MW below its 100 MW requirement.
- Because there is no system shortfall for capacity, the CAISO will not make a CPM designation, but because the showing from LSE 3 is below the requirement, the UCAP deficiency will trigger, and LSE 3 is assessed a charge for 10 MW * $6.31/kW-month, or $63,100.
- This charge is then allocated to LSE 1 and LSE 2, where entity 1 receives 10/25 = 40% or $25,240 and entity 2 receives 15/25 = 60% or $37,860.
- LSE 1 and 3 would have benefitted more from contracting with one another. Even if they had contracted for at least half of the soft over cap 10 MW*$3.16, LSE 1 would have earned $31,600, which is $6,360 more than they would have earned from UCAP Deficiency tool payment, and LSE 3 could have saved $31,500. This demonstrates that this tool would not incentives withholding of excess capacity, because LSE 1 could profit more from selling to LSE 3 than taking the risk that they would receive the UCAP Deficiency Payment.

Figure 12: UCAP Deficiency Tool, no Backstop

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	Penalty	Payment
1	100	110			$25,240
2	100	115			$37,860
3	100	90	10	$63,100	
TOTAL	300	315	10	$63,100	$63,100

The second scenario shows a system shortfall, but CAISO does not issue a CPM designation.

- In this example LSE 1 and LSE 2 show UCAP below their 100 MW requirements, at 10 MW and 15 MW respectively, and LSE 3 shows five MW above its 100 MW requirement.
- In this scenario, the CAISO could potentially procure backstop capacity to cure the 20 MW system UCAP deficiency, but chooses note to make such a designation.
- In this case, the two LSEs that are short are assessed a charge for the capacity matching the UCAP deficiency. However, the charge is limited because a maximum payment of $6.31/kW-month is reached for the payment recipient.
- Because LSE 1 is 10 MW of the 25 MW of total shortage it is assessed a charged of $6.31/kW * 5 MW * (10 MW / 25 MW) = $12,620 and LSE 2 is assessed a charge of $6.31/kW * 5 MW * (15 MW / 25 MW) = $18,930.
- Because LSE 3 is the only entity showing above the requirements, all of the collected charges are allocated back to that LSE, in this case the total amount allocated is $31,550 or $6.31/kW * 5 MW.
- Note that there is a mutually beneficial solution where LSE 3 could have paid LSE 1 less than the $63,100 it was charged and that LSE 1 would have made more than the $25,210 it received from the deficiency payment. This shows there is unlikely to be an incentive to withhold capacity under this mechanism.

Figure 13: UCAP Deficiency Tool, with Aggregate Shortfall

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	Penalty	Payment
1	100	90	10	$12,620	
2	100	85	15	$18,930	
3	100	105			$31,550
TOTAL	300	280	25	$31,550	$31,550

In the third example LSE 2 and LSE 3 both show below their 100 MW month-ahead requirements and LSE 1 shows exactly at its 100 MW requirement.

- In this scenario, the aggregate amount of UCAP shown is below the aggregate amount of UCAP required for the UCAP requirements.
- In this case, CAISO could potentially procure backstop capacity to cure the system UCAP deficiency.
- Irrespective of any CPM designation, CAISO will not charge any market participants for the shortfall, as there is no entity to allocate those charges.

Figure 14: UCAP Deficiency Tool, no Award Recipients

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	Penalty	Payment
1	100	100			
2	100	80	20		
3	100	95	5		
TOTAL	300	275	25	$0	$0

Example: UCAP Deficiency Tool with CAISO backstop

In this example LSE 1 and LSE 2 both show below their 100 MW month-ahead requirements and LSE 3 shows above the 100 MW requirement.

- In this scenario, LSE 1 is again short 10 MW and LSE 2 is short 15 MW. Additionally, because LSE 3 only procures five MW above its requirement, there is a shortage between the aggregate amount of UCAP shown and the aggregate requirement.
- This shortfall triggers a CAISO CPM designation, for the 20 MW deficiency.
- CAISO then allocates eight MW of the CPM procurement to LSE 1 and 12 MW to LSE 2.
- The shortfall persists even with the adjustment for the CPM allocation, and the shortfall equals five MW or exactly the capacity that that LSE 1 showed above its requirement.
- Therefore, the remaining shortfall, inclusive of the CPM allocation, is two MW for LSEs 1 and three MW for LSE 2, which is then subject to the UCAP deficiency tool penalty.
- Penalties assessed are for $12,620 for LSE 1 and $18,930 for LSE 2.
- The $31,550 of the collected revenues are then credited to LSE 3.

Figure 15: UCAP Deficiency Tool, with Backstop

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	CPM Alloc (MW)	Adj Short (MW)	Penalty	Payment
1	100	90	10	8	2	$12,620	
2	100	85	15	12	3	$18,930	
3	100	105					$31,550
TOTAL	300	280	25	20	5	$31,550	$31,550

BACKSTOP: 20 MW

5. Implementation Plan

The CAISO understands this is a challenging and comprehensive initiative. Given these implementation considerations, the CAISO is planning a phased implementation. The first phase includes stand-alone elements that can be implemented relatively quickly. For UCAP and Portfolio analysis, phase one allows additional time for CPUC coordination, system development, and offline demonstrations prior to these elements becoming a part of the RA requirements. The second phase includes full implementation of foundational elements with interdependencies, including UCAP requirements and counting rules, the portfolio analysis, and elements that are needed to align with the day-ahead market enhancements and the extended day-ahead market initiatives. These targeted dates are tentative and subject to change.

Phase One: (2021 for RA year 2022)

- RA Import provisions
- Planned outage process enhancements
- Local studies with availability limited resources CPM clarifications
- Operationalizing Storage
- UCAP - Phase 1
- Portfolio Assessment - Phase 1

Phase Two: (2022 for RA year 2023)

- UCAP - Phase 2
- Portfolio Assessment - Phase 2
- Must offer obligations and bid insertion rules
- Flexible resource adequacy

CAISO seeks stakeholder feedback on the proposed phases, including the order these policies must roll out and the feasibility of the proposed implementation schedule.

6. EIM Governing Body Role

For this initiative, the CAISO plans to seek approval from the CAISO Board only. This initiative falls outside the scope of the EIM Governing Body's advisory role because the initiative does not propose changes to either real-time market rules or rules that govern all CAISO markets. This initiative is focused on the CAISO's RA planning, procurement, and performance obligations. This process applies only to LSEs serving load in CAISO's BAA and the resources procured to serve that load, and does not apply to LSEs outside CAISO's BAA. The CAISO did not receive any specific feedback from stakeholders regarding the initial proposed EIM classification for this initiative. The CAISO continues to seek stakeholder feedback on this proposed decisional classification for the initiative.

7. Next Steps

The CAISO will discuss this third revised straw proposal with stakeholders during a stakeholder meeting on July 14-16, 2020. Stakeholders are asked to submit written comments by July 30, 2020 to initiativecomments@caiso.com. A comment template will be posted on the CAISO's initiative webpage here:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx

8. Appendix

8.1. Resource Adequacy Enhancements Principles and Objectives

Principles

<u>The resource adequacy framework must reflect the evolving needs of the grid</u>

As the fleet transitions to a decarbonized system where fuel backed resources are replaced with clean, variable, and/or energy-limited resources, traditional measures of resource adequacy must be revisited to include more than simply having sufficient capacity to meet peak demand. The RA products procured and the means to assess resource adequacy must be re-examined and refreshed to remain relevant. Any proposed changes must assure that RA accounting methods effectively evaluate the RA fleet's ability to meet the CAISO's operational and reliability needs all hours of the year. The evolving fleet is altering the CAISO's operational needs. As more variable supply and demand interconnects to the system, the CAISO requires resources that are more flexible and can quickly and flexibly respond to greater levels of supply and demand uncertainty. RA requirements and assessments must reflect the evolving needs of the grid and the RA framework must properly evaluate and value resources that can meet these evolving needs.

<u>RA counting rules should promote procurement of the most dependable, reliable, and effective resources</u>

Both RA and non-RA resources should be recognized and rewarded for being dependable and effective at supporting system reliability. If a non-RA resource has a higher availability and is more effective at relieving local constraints relative to other similar RA resources, then such information should be publicly available to enable load-serving entities (LSEs) to compare and contrast the best, most effective resources to meet their procurement needs. Having this information publicly available to load-serving entities will improve opportunities for the most dependable and effective resources to sell their capacity. Thus, in principle, RA counting rules should incentivize and ensure procurement of the most dependable, reliable, and effective resources.

<u>The RA program should incentivize showing all RA resources</u>

Modifications to the existing RA structure should encourage showing as much contracted RA capacity as possible and not create disincentives or barriers to showing excess RA capacity. Although it may be appropriate to apply additional incentive mechanisms for availability, CAISO must balance the impact that such incentives may have on an LSE's willingness to show all of its contracted RA capacity.

<u>LSE's RA resources must be capable of meeting its load requirements all hours of the year</u>

RA targets should be clear, easily understood and based on reasonably stable criteria applied uniformly across all LSEs. For example, to date, the CAISO has relied on a planning reserve margin that is met through a simple summation of the shown RA resources' Net Qualifying

Capacity (NQC) values. Most Local Regulatory Authorities (LRAs) set a planning reserve margin at fifteen percent above forecasted monthly peak demand. However, some LRAs have set lower planning reserve margins. It is not possible to determine if those LSEs with lower planning reserve margins impair the CAISO system without comparing the attributes of the underlying resources in LSE's portfolios, relative to resources' attributes in other portfolios. In other words, the simple summation of NQC values in a LSE's portfolio does not does not guarantee there will be adequate resources and does not assure an LSE can satisfy its load requirements all hours of the year. As California Public Utilities Code section 380 states, "Each load-serving entity shall maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves (emphasis added)."[87] In other words, resource adequacy also encompasses LSEs meeting their load requirements all hours of the year, not just meeting peak demand.

Objectives

In evaluating RA enhancements, CAISO is reviewing NQC rules, forced outage rules, adequacy assessments, and availability obligations and incentive provisions. These existing rules are inextricably linked and require a holistic review and discussion. This review includes considering assessing the reliability and dependability of resources based on forced outage rates. Incorporating forced outages into the CAISO's RA assessment will help inform which resources are most effective and reliable at helping California decarbonize its grid.

Based on the CAISO's review of best practices and the diverse stakeholder support for further exploration of these matters, CAISO is proposing a new resource adequacy framework to assess the forced outage rates for resources and conduct RA adequacy assessments based on both the unforced capacity of resources and the RA portfolio's ability to ensure CAISO can serve load and meet reliability standards.

The CAISO's proposal seeks to remain aligned with the CPUC process. However, CAISO notes that solely relying on an installed-capacity-based PRM as the basis for resource adequacy, as is the case today, is not sustainable into the future given the transforming grid and the new resource mix and its operational characteristics.

The CAISO must consider the express intent of the original legislated RA mandate: to ensure each load-serving entity maintains physical generating capacity and electrical demand response adequate to meet its load requirements. This is essential as California transitions to greater reliance on more variable, less predictable, and energy limited resources that may have sufficient capacity to meet a planning reserve margin, but may not have sufficient energy to meet reliability needs and load requirements all hours of the year. Given this growing concern, CAISO is proposing to develop a new resource adequacy test that will ensure there is sufficient

[87] California Public Utilities Code Section 380: http://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=2.3.&article=6.

capacity to not only meet peak load needs, but, just as importantly, to ensure sufficient energy is available within the RA fleet to meet load requirements all hours of the year.

As noted above, the current RA practices rely heavily on the existing NQC counting rules. CAISO believes that resources' NQC values will continue to be an important aspect of the RA program in the future. CAISO envisions Must Offer Obligations being tied to NQC values. However, CAISO is also considering how to incorporate resource forced outage rates into system, flexible, and local RA assessments. Similar to the current provisions of other ISOs, the CAISO proposes calculating and publishing both installed capacity (NQC) and unforced capacity (UCAP) values and utilizing both figures in the CAISO's RA processes.

8.2. Unit Outage Rate Analysis Examples

The CAISO received feedback requesting analysis supporting the proposed inclusion of a unit's forced outage rates for capacity valuation and conducted some preliminary analysis to assess the proposal's potential impacts. NERC GADS data for WECC shows a WECC-wide average forced outage rate for all resource types providing outage data of approximately 8%. The CAISO analyzed a subset of unit outage data and included some examples of the resulting analysis in the following figures.

The CAISO made the assumptions and utilized the formulas below for determining the following example outage analyses.

Assumptions:

- For any Forced Outages lasting over 7 days, change to planned outage
- For overlapping forced outages, sum of all outages are accounted for in calculations

Calculation formulas

$$\boldsymbol{Forced\ Outage\ Rate} = \frac{\sum_{area} \boldsymbol{Pmax} - \sum_{area} \boldsymbol{Forced\ Avail\ MW}}{\sum_{area} \boldsymbol{Pmax}}$$

$$\boldsymbol{Planned\ Outage\ Rate} = \frac{\sum_{area} \boldsymbol{Pmax} - \sum_{area} \boldsymbol{Planned\ Avail\ MW}}{\sum_{area} \boldsymbol{Pmax}}$$

$$\boldsymbol{Total\ Outage\ Rate} = \frac{\sum_{area} \boldsymbol{Pmax} - \sum_{area} \boldsymbol{Total\ Avail\ MW}}{\sum_{area} \boldsymbol{Pmax}}$$

Example Outage Analysis Results

The following figures provide the results of the CAISO's outage analysis for two example resources. It illustrates the magnitude of outages these example resources had over the 2018 annual and summer periods. The CAISO's analysis shows that resource availability related to forced outages varies over seasons and between resources. Significant variance in resource forced outage rates is precisely the issue the CAISO's proposed UCAP modifications are intended to capture.

Figure 16: Example Unit #1 – Seasonal outage rate analysis: summer 2018

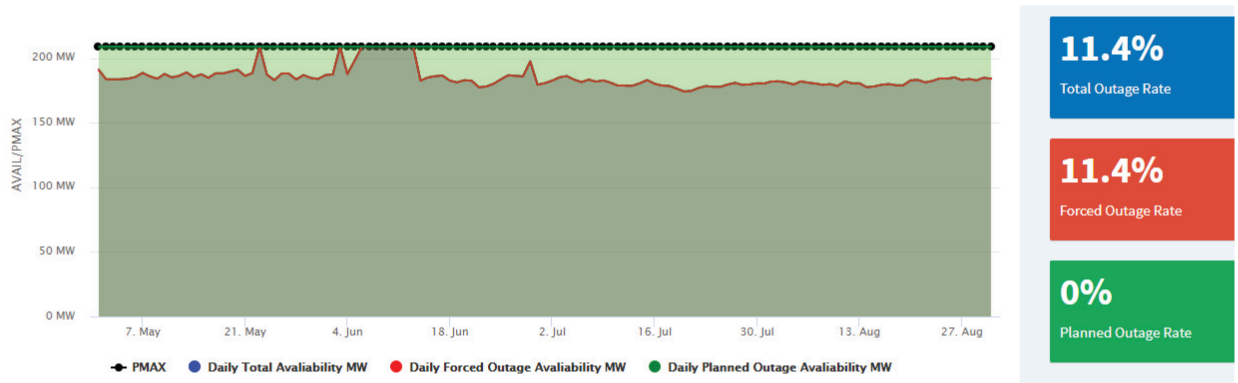


Figure 17: Example Unit #1 – Annual outage rate analysis: 2018

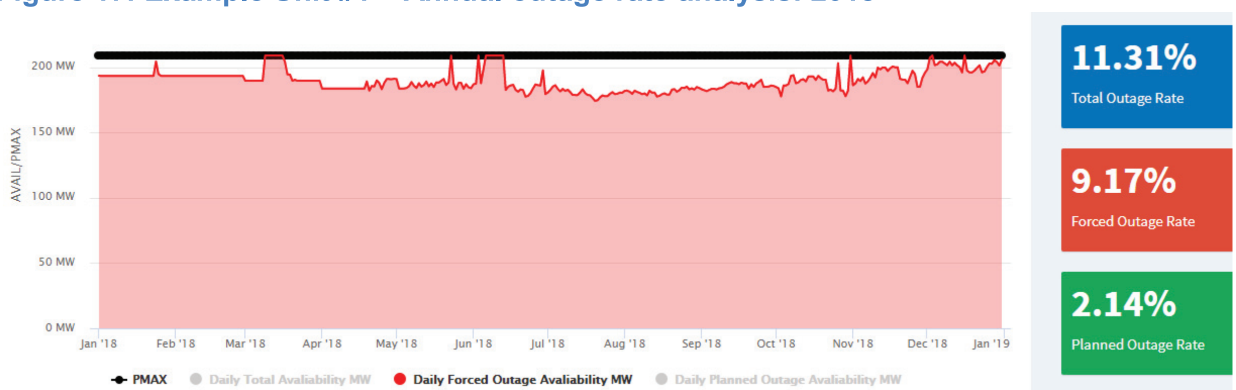


Figure 18: Example Unit #2 – Seasonal outage rate analysis: summer 2018

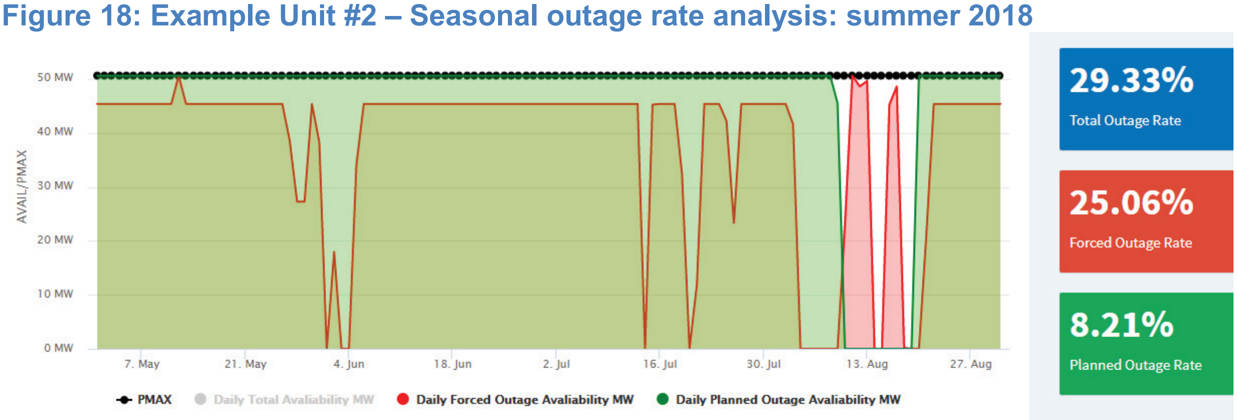
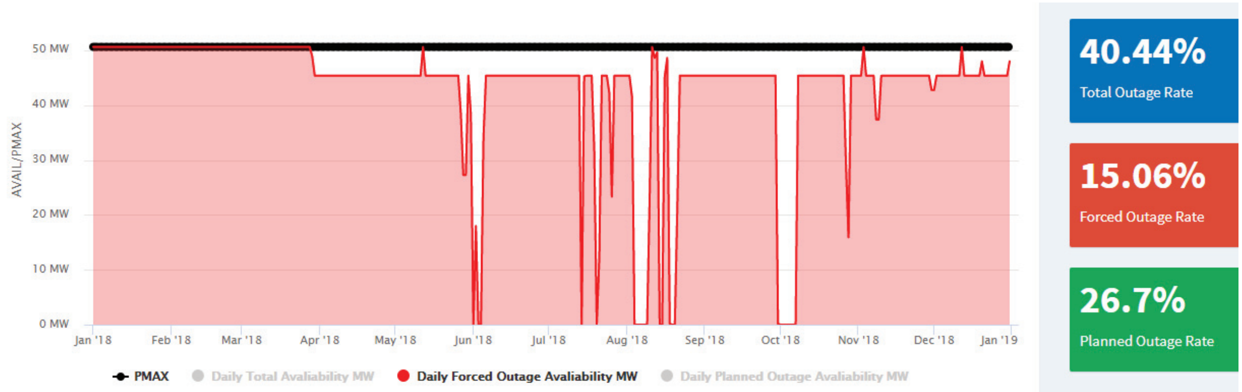


Figure 19: Example Unit #2 – Annual outage rate analysis: 2018



The example resource forced outage analysis is for illustrative purposes only and any final proposal will provide detailed calculation parameters and inputs.

8.3. RAAIM and Forced Outage Substitution Analysis

The CAISO's existing RAAIM provisions rely on different availability assessment hours (AAHs) for determining the hours of greatest need for each capacity product, which adds significant complexity. The AAHs for generic capacity are the five peak load hours on non-holiday weekdays. The AAHs for flexible capacity differ in both hours and duration. Category 1 flexible capacity has a 17-hour assessment interval for all days designed to cover both the morning and evening ramps. Flexible capacity categories 2 and 3 have 5-hour assessment windows designed to cover the maximum net load ramp. Flexible capacity category 2 assessment hours covers all days and category 3 covers only non-holiday weekdays. The AAHs can change annually for both generic and flexible capacity.

The RA program is designed to ensure the CAISO has sufficient capacity available to serve load reliably through its market dispatch. Any resource providing RA capacity to the CAISO has an obligation to offer that capacity into the CAISO's markets. The Must Offer Obligations (MOO) for various RA and technology types are listed in the CAISO's Reliability Requirements BPM.[88] CAISO also relies on outage reporting to track whether resources are available at any given time. If there is sufficient notice given and capacity available, the CAISO can grant outages without requiring replacement capacity. However, not all outages occur under those conditions, and the CAISO developed RAAIM to address these particular instances.

RAAIM was designed to provide an incentive for resources on outage to minimize the duration of the outage or to provide substitute capacity. Additionally, RAAIM provides an additional incentive payment to generation that is available over a predetermined measurement. RAAIM does not apply to all hours; it only applies during the Availability Assessment Hours. These hours and days differ depending on the RA product the resource is providing to CAISO. Although RAAIM provides an incentive to provide substitute capacity, it also provides an incentive to only show the bare minimum RA capacity needed for each capacity type, because

[88] See the Reliability Requirements BPM, pp. 77-82 for System and Local RA obligations and pp. 93-96 for flexible RA obligations.

showing additional capacity exposes that capacity to RAAIM non-availability charges – without providing any corresponding benefit to the LSE to which that resource is contracted.

The CAISO reviewed the effectiveness of RAAIM to incentivize resources to provide replacement during forced outages. As a starting point, CAISO reviewed data from the CIRA, system. Data was pulled from May 1, 2018 through July 31, 2019. CAISO compared the quantity of shown RA MW for a given day, the reported MWs of capacity on forced outage, and the MWs of forced outage substitute capacity provided. The CAISO did not differentiate the cause of the forced outage, including whether or not the outage was exempt from RAAIM. At the core, the effectiveness of RAAIM should not be measured simply by how much of capacity is replaced for certain outage types, but by how well it ensures there is adequate capacity available to CAISO. Even if the vast majority of outages are RAAIM exempt, CAISO may be left with insufficient capacity. Figure 20 shows that, overall, very little substitute capacity is being provided to the CAISO in response to forced outages. Additionally, the CAISO understands that there may be limited capacity available in some local areas to provide substitute capacity. The CAISO conducted a similar assessment of system level capacity and found, with very limited exceptions, similar results. These results are shown in Figure 21.

Figure 20: Forced Outages vs Replacement Capacity (All)

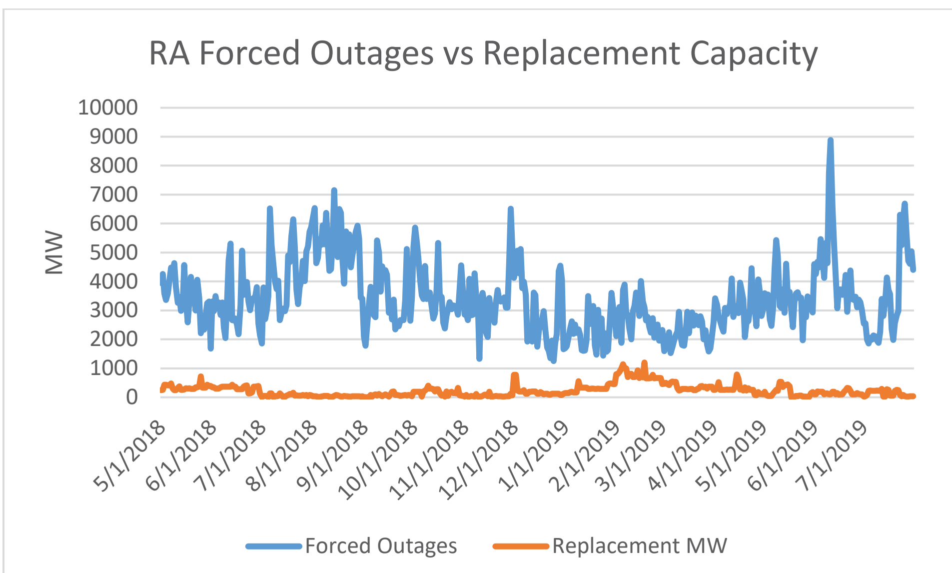
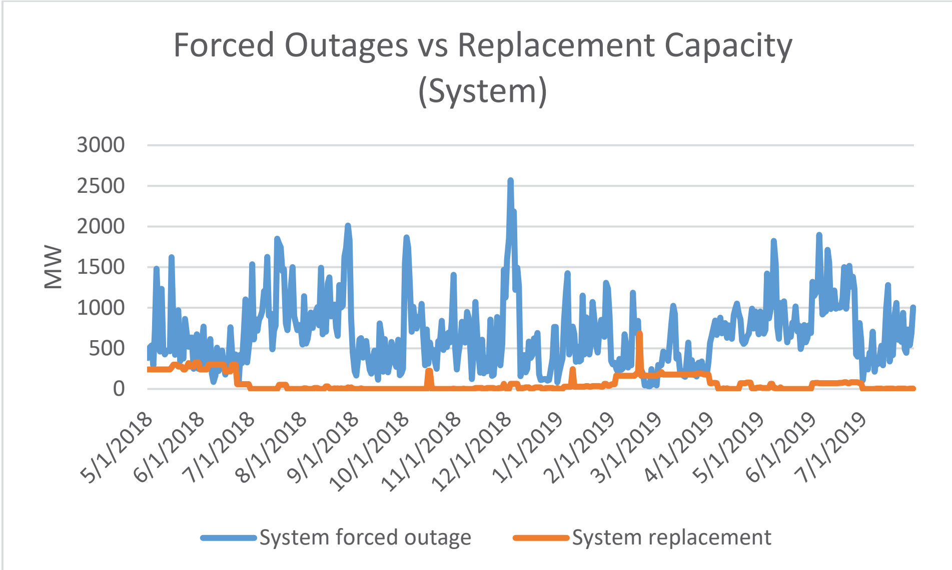


Figure 21: Forced Outage vs Replacement Capacity (System Only)



The CAISO concludes that RAAIM is not providing adequate incentive to provide substitute capacity for forced outages and proposes to eliminate it once UCAP is implemented. The CAISO cannot ascertain if the risk of RAAIM charges is already incorporated into capacity pricing, if RAAIM costs are not high enough, or if benefits are spread too thin to motivate substitution. Other factors could include portfolio effects (*i.e.*, an SC receives similar RAAIM charges and incentives, balancing each other out), too many RAAIM exclusions/exemptions, the dead band applying for the first outages, or some other reasons.