2021 LIMITED LOCAL CAPACITY TECHNICAL STUDY

Special Report for the State Water Resources Control Board to Determine Alamitos OTC Permit Extension

Version 1.1

July 11, 2019

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Executive Summary

This report documents the results and recommendations of the 2021 Limited Local Capacity Study prepared specifically to assess the need for requesting an extension of the Once-Through Cooling (OTC) compliance date for the Alamitos Generating Station beyond the December 31, 2020 date established by the State Water Resources Control Board in the Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Policy). This study report follows the study processes and criteria that were discussed and recommended for the 2020 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2018. The study assumptions, processes, and criteria used for the 2021 Limited Local Capacity Study for the Alamitos OTC generation implementation schedule extension mirror those used in the 2007-2020 Local Capacity Technical (LCT) Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The load forecast used in this study is based on the final adopted California Energy Demand Updated Forecast, 2018-2030 developed by the CEC; namely the load-serving entity (LSE) and balancing authority (BA) mid baseline demand with low additional achievable energy efficiency and photo voltaic (AAEE-AAPV), posted on February 5, 2019: https://efiling.energy.ca.gov/GetDocument.aspx?tn=226462&DocumentContentId=57239.

The following summary includes major findings related to the need for Alamitos OTC implementation schedule extension from this 2021 local capacity study:

1. Study results based on the most recent CEC-adopted 2018-2030 California Energy Demand Update (CEDU) Forecast from the 2018 Integrated Energy Policy Report (IEPR) process do not trigger the need for Alamitos OTC implementation schedule extension. The lower demand forecast in the 2018 IEPR compared to the 2017 IEPR, coupled with partial completion of the Mesa Loop-in Project (i.e., completion of the 230-kV loop-in portion of the project), as well as completion of the the Lugo-Mohave and Lugo-Eldorado 500 kV line series capacitor upgrades and returning them to service[2] help reduce the local capacity requirements in the LA Basin from previous study results.
2. The ISO has also conducted a sensitivity study to assess the risk associated with forecast uncertainty, given that these studies will ultimately be updated with the latest forecast information in the normal course of the 2021 Local Capacity Technical Study efforts in the spring of 2020. There were two scenarios evaluated for this sensitivity study:

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

[2] The Lugo-Mohave and Lugo-Eldorado 500 kV line series capacitors are bypassed while they are being upgraded in 2020 timeframe.

a. A scenario based on approximately 800 MW higher load across the SCE service territory[3]. This demonstrated a need for Alamitos OTC generation of 476 MW;

b. A second incorporating the higher demand forecast in the first scenario, but evaluated without the use of 360 MW of potential non-OTC "at-risk-of-retirement" generation.[4] For this scenario, the need for Alamitos OTC generation increased to 816 MW.

Note that Alamitos Units 1, 2 and 6 are scheduled to be retired by the end of 2019 to allow for transfer of emission credits to the new repowering 640 MW Alamitos combined cycle generating facility. This will leave only three remaining OTC units on site: Units 3 (320 MW), 4 (320 MW) and 5 (480 MW) for OTC schedule extension consideration.

The CAISO also notes that in the CPUC Assigned Commissioner and Administrative Law Judge Ruling of June 20, 2019, in Rulemaking 16-02-007, the option of "Extending deadlines for some portion of planned OTC retirements until new procurement is authorized or online"[5] was proposed to mitigate against potential system-wide capacity shortages beginning in 2021. Further, the Ruling suggested "that the appropriate individuals within staff of the Commission begin discussions through appropriate channels with the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) to the State Water Resources Control Board (Water Board), under whose jurisdiction the OTC retirements are set"[6], regarding potentially postponing the retirement of one or more OTC units by a year or two.

In light of the inherent forecast risk and the sensitivity of the local capacity requirement results for the need for Alamitos to load forecast levels, as well as the potential need for extension of OTC compliance for system capacity, the CAISO considers it prudent to commence activities seeking an extension to the OTC compliance date for Alamitos at this time. Actual procurement levels would depend on the 2021 local capacity technical study requirements developed early in 2020, or, possibly, by the need for system capacity determined by the CPUC.

[3] 800 MW represents the approximate difference in load in the SCE service territory between the 2017 IEPR and 2018 IEPR.

[4] 260 MW of this generation was assumed to be retired as part of the Scoping Ruling from the CPUC Long-Term Procurement Plan (LTPP) Track 4 Study (Rulemaking 12-03-014) due to age of the generation before its refurbishment; the other 100 MW generation had mothballed status previously but withdrew its mothball request in Q4 2018 after securing a power contract with SCE.

[5] Page 14, CPUC Assigned Commissioner and Administrative Law Judge Ruling of June 20, 2019, in Rulemaking 16-02-007, Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements

[6] Page 15, id

Summary of Local Capacity Technical Study Results

The 2020 and 2021 total LCR needs are provided below:

2021 Local Capacity Needs

	Qualifying Capacity				Capacity Available at Peak	2021 LCR Need Category B	2021 LCR Need Category C	Alamitos OTC Capacity Need Extension (MW)
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Grid-connected Solar (MW)	Total (MW)	Total (MW)	Capacity Needed (MW)	Capacity Needed (MW)	
Study Results based on 2018 IEPR's 2018-2030 CEDU Forecast[7] (Most Recent Adopted Forecast)								
LA Basin	1,344	6,934	17	**8,295**	**8,295**	5,946	**6,246**	None
Western LA Basin Subarea	640	3,738	0	**4,378**	**4,378**	N/A	**3,965**	None
San Diego/ Imperial Valley	4	4,032	523	**4,559**	**4,036**	3,944	**3,944**	N/A
Sensitivity Study Results based on 2017 IEPR's 2018-2030 CED Forecast (Previously Adopted Forecast)								
Scenario 1 Sensitivity Study								
LA Basin	1,344	6,934	17	**8,295**	**8,295**	N/A	**7,102***	476
Western LA Basin Subarea	640	3,738	0	**4,378**	**4,378**	N/A	**4,800***	476
San Diego/ Imperial Valley	4	4,032	523	**4,559**	**4,036**	3,944	**3,944**	N/A
Scenario 2 Sensitivity Study								
LA Basin	1,344	6,574	17	**7,935**	**7,935**	N/A	**7,082***	816
Western LA Basin Subarea	640	3,378	0	**4,018**	**4,018**	N/A	**4,780***	816
San Diego/ Imperial Valley	4	4,032	523	**4,559**	**4,036**	3,944	**3,944**	N/A

Notes: * Area or subarea is resource deficient. An overall LCR area can also be resource deficient if its subarea(s) are resource deficient.

2020 Local Capacity Needs[8]

[7] The 2018 IEPR 2018-2030 CEDU Forecast is the most recent adopted demand forecast that was used for the baseline LCR study.

[8] The 2020 LCR study results were based on the 2018 IEPR 2018-2030 CEDU Forecast, which is the same demand forecast that was used for the 2021 Limited LCR baseline study.

	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**
LA Basin	1,344	9,078	17	**10,439**	**10,104**	7,364	**7,364**
Western LA Basin Subarea	639	5,913	0	**6,552**	**4,378**	N/A	**3,706**
San Diego/ Imperial Valley	4	3,891	439	**4,334**	**3,895**	3,895	**3,895**

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1 Overview of the Study: Inputs, Outputs and Options

1.1 Objectives

The CAISO undertook a separate and special 2021 Limited Local Capacity Study to preliminarily assess the local capacity requirements for the LA Basin and San Diego/Imperial Valley local capacity areas, and to consider the need for requesting an extension of the Once-Through Cooling (OTC) compliance date for the Alamitos Generating Station beyond the December 31, 2020 date established by the State Water Resources Control Board in the Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Policy). This study followed the study processes and criteria that were discussed and recommended for the 2020 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2018.

The study assumptions, processes, and criteria used for the 2021 Local Capacity Study for the Alamitos OTC generation implementation schedule extension mirror those used in the 2007-2020 Local Capacity Technical (LCT) Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[9], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

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 2020 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2018. They are similar to those used and incorporated in previous LCT studies. The following table sets out a summary of the approved inputs and methodology that have been used in this 2021 Limited LCT Study, which were based largely on those used in the 2024 Long-Term LCT Study prepared by the CAISO earlier in 2019:

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

Issue	How Incorporated into this LCT Study:
Input Assumptions:	

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

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:	
Performance Level B & C, including incorporation of PTO operational solutions	This LCT Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, of the study year. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study.

Load Pocket:	
Fixed Boundary, including limited reference to published effectiveness factors	This LCT Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2024 Long-Term LCT Study methodology and assumptions, also employed in this 2021 Limited LCT Study, 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.[10] 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 Local Capacity Technical Study will determine the minimum amount of Local Capacity Area Resources needed to address the Contingencies identified in the CAISO Tariff Section 40.3.1.2. In performing the Local Capacity Technical Study, the CAISO will apply those methods for resolving Contingencies considered appropriate for the performance level that corresponds to a particular studied Contingency, as provided in NERC Reliability Standards TPL-001-4, as augmented by CAISO Reliability Criteria in accordance with the Transmission Control Agreement and Section 24.2.1. It is noted that the CAISO is currently undergoing a stakeholder process[11] to review and update the Local Capacity Technical (LCT) Study criteria, pursuant to the ISO Tariff section 40.3.1.1 and contingencies identified in section 40.3.1.2. The ISO will update the criteria and contingencies to align them in form and substance with current national (i.e., NERC) and regional (i.e., WECC) mandatory standards.

[10] Pub. Utilities Code § 345

[11] http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityTechnicalStudyCriteriaUpdate.aspx

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[12] NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as WECC-S2 (for 500 kV only) ("any two circuits in the same right-of-way") with no manual system adjustment between the two contingencies.

1.5 Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCR Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC standards for the same NERC performance levels. These Performance Levels can be described as follows:

1.5.1 Performance Criteria- Category B

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

Category B system performance requires that 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.

1.5.2 Performance Criteria- Category C

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

[12] NERC Category B and C terminology no longer aligns with the current NERC standards. It is used in this report since the ISO Tariff still uses this terminology that was in effect at the time when the ISO Tariff section was written.

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

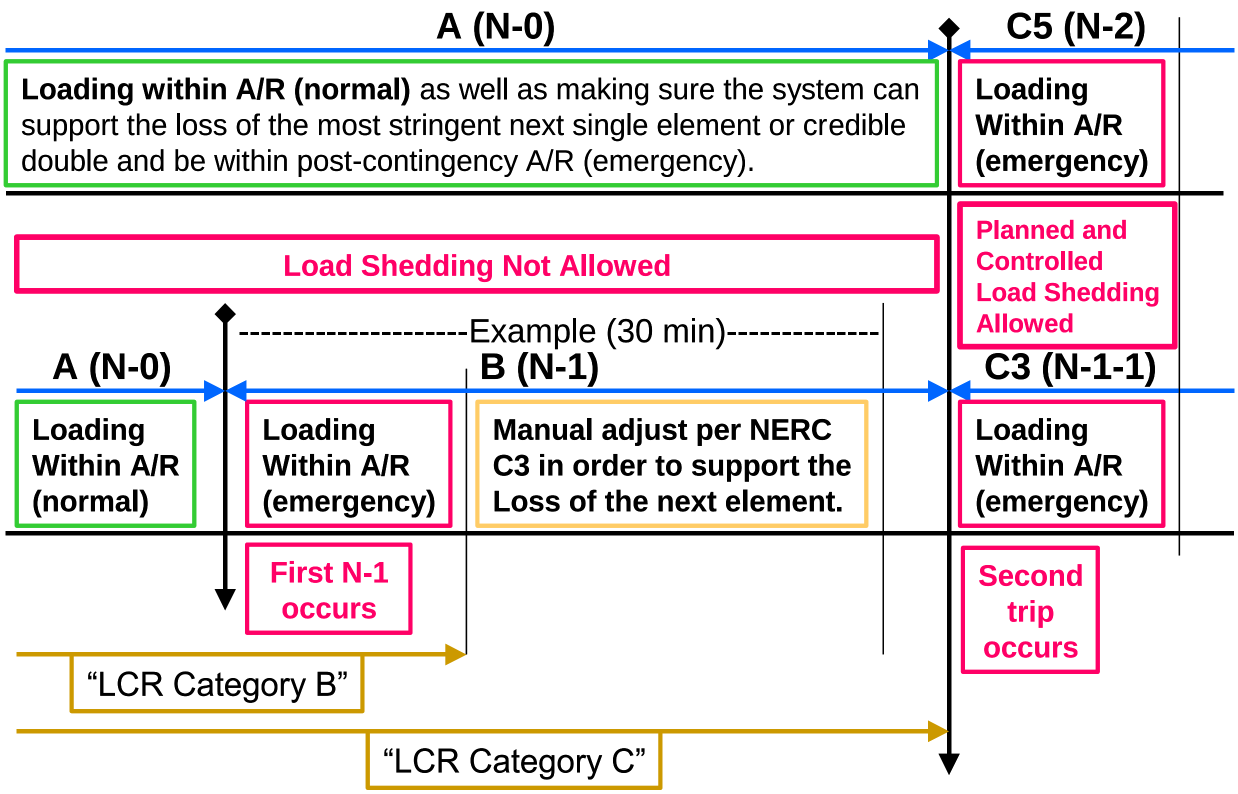
Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as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

1.5.3 CAISO Statutory Obligation Regarding Safe Operation

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

Figure 1.5-1 Temporal graph of LCR Category B vs. LCR Category C

[13] 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.



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 single contingency (Category B):

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

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

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

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

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

Time allowed for manual readjustment:

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

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

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

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

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

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

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

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

1.6 The Two Options Presented In This Limited LCT Study Report

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

1.6.1 Option 1 - Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[14]

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

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

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

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

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

Contingency Component(s)	ISO Grid Planning Criteria	Old RMR Criteria	Local Capacity Criteria
A – No Contingencies	**X**	**X**	**X**
B – Loss of a single element			
1. Generator (G-1)	X	X[1]	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
C – Loss of two or more elements			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode) L-2	X		X
6. SLG fault (stuck breaker or protection failure) for G-1	X		
7. SLG fault (stuck breaker or protection failure) for L-1	X		
8. SLG fault (stuck breaker or protection failure) for T-1	X		
9. SLG fault (stuck breaker or protection failure) for Bus section	X		
WECC-S3. Two generators (Common Mode) G-2	X[3]		X
D – Extreme event – loss of two or more elements			
Any B1-4 system readjusted (Common Mode) L-2	X[4]		X[3]
All other extreme combinations D1-14.	X[4]		

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

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

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

[4] Evaluate for risks and consequence, per NERC standards.

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

2.1.1 Power Flow Assessment:

Table 2.1-2 Power flow criteria

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

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

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

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

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

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

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

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2

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

2.1.2 Post Transient Load Flow Assessment:

Table 2.1-3 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 2.1-4 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[15] 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.

[15] 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.

2.2.2.2 *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_05 and PowerGem's Transmission Adequacy and Reliability Assessment (TARA) program version 1702. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member and TARA program is commercially available.

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

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. 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.

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) / Available Resources at Peak Load (MW)	2021 LCR as % of Total NQC
LA Basin	6,246	19,330	32%	8,295	75%**
San Diego/Imperial Valley	3,944	4,635	85%	4,559 / 4,036	87% / 98%
Total	**10,190**	**23,965***	**43%**	**12,854 / 12,331**	**79% / 83%**

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

** Resource deficient LCA (or with sub-area that are deficient) – deficiency included in LCR. 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 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. The NQC list in Attachment A does not include Demand Side Management programs and their related NQC. However, the amount of demand response used in each study area is included in the study results for each area. Resources scheduled to become operational before June 1 of 2021 have been included in this 2021 Local Capacity Study Report (for evaluation of Alamitos local capacity need). Those resources capacity values are added to the total NQC values for those respective areas (see detail write-up for each area in Section 3).

Regarding the main tables up front (page 2), the first column, "Qualifying Capacity," reflects two sets of resources. The first set is comprised of resources that would normally be expected to be on-line such as Municipal and Regulatory Must-take resources (state, federal, QFs, wind and nuclear units). The second set is "market" resources. The second column, "YEAR LCR Requirement Based on Category B" identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B. The third column, "YEAR LCR Requirement Based on Category C with Operating Procedure", sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

3.2 Summary of Results by Local Area

Each local capacity area's overall requirement is determined by achieving each sub-area requirement as well as the overall local capacity area's requirement. Because these sub-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. This is because some sub-areas may overlap and therefore the same generating units may count for meeting the needs in those sub-areas. When aggregating for the overall local capacity area requirement, those generating units are accounted once for the overall local capacity need.

3.2.1 LA Basin Area

3.2.1.1 *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 – 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

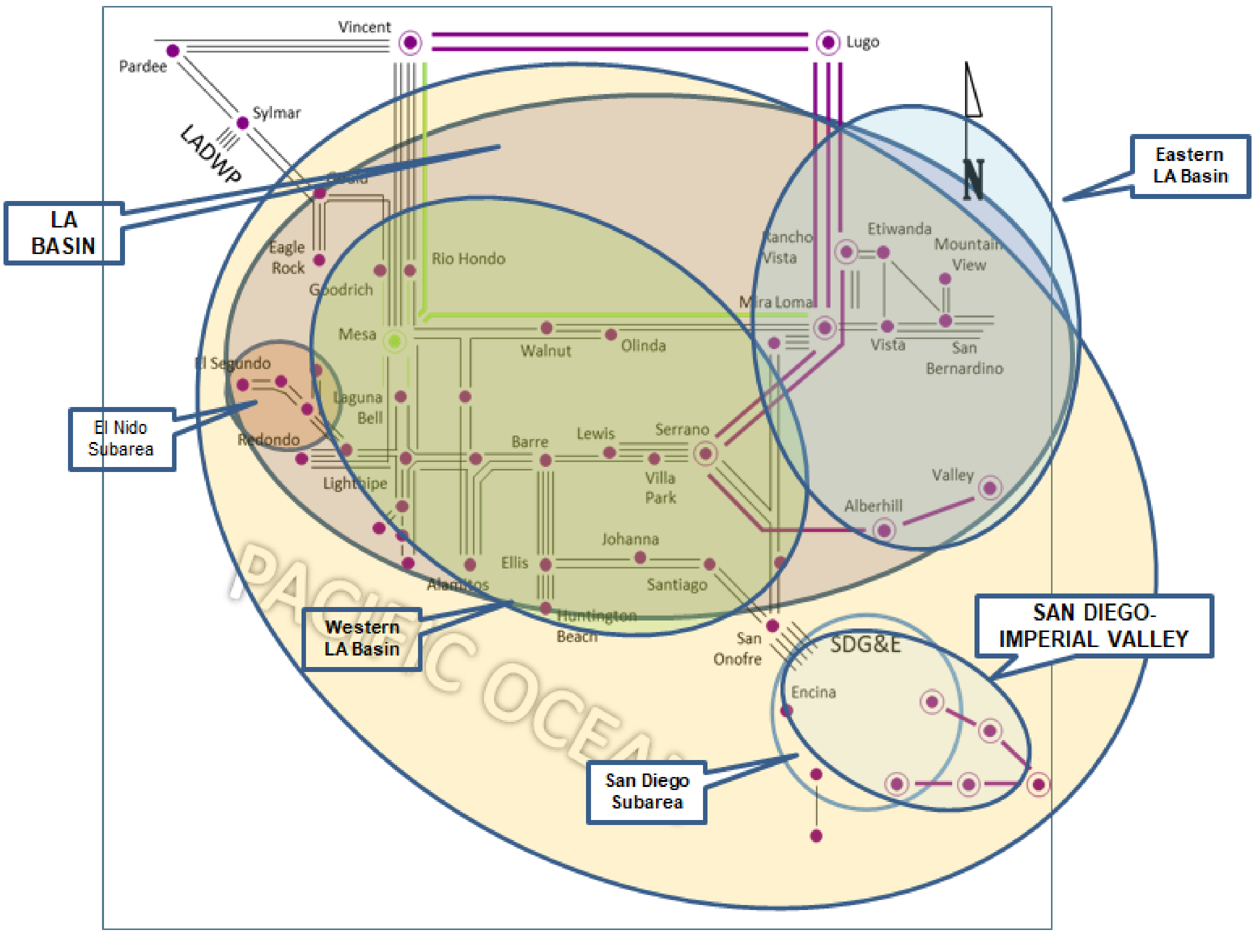
The substations that delineate the LA Basin Area are:

- 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

3.2.1.1.1 LA Basin LCR Area Diagram

Figure 3.2-1 LA Basin LCR Area



3.2.1.1.2 LA Basin LCR Area Load and Resources

Table 3.2-1 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 as well as the existing 20-minute demand response. These resources are included in the Table 3.2-1.

In the year 2021, the estimated time of local area peak demand occurs at 5:00 p.m. PDT on September 7th.

At the local area peak time the estimated, behind the meter, solar output is 26%.

At the local area peak time the estimated, ISO metered, solar output is 33.4%.

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

Table 3.2-1 LA Basin LCR Area 2021 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**NQC**	**At Peak**
Gross Load	21,078	Market, Net Seller, Battery, Wind, Solar	5,975	5,975
AAEE	-364	MUNI	1,110	1,110
Behind the meter DG	-1,689	QF	234	234
Net Load	**19,025**	LTPP Preferred Resources	374	374
Transmission Losses	285	Existing 20-minute Demand Response	267	267
Pumps	20	Mothballed	335	335
Load + Losses + Pumps	**19,330**	**Total**	**8,295**	**8,295**

The total load plus losses and pump loads above is for the LA Basin geographic area (same area from the CEC's demand forecast for the LA Basin in the LSE/BA Table). However, the electrically defined LA Basin LCR area does not include Saugus substation load, which is 736 MW. When Saugus load is subtracted from the geographically defined LA Basin load and losses (19,330 MW), the total load plus losses for the electrically defined LA Basin area is estimated to be 18,594 MW.

3.2.1.1.3 Approved transmission and resource projects modeled:

- Mesa Loop-In Project (230 kV portion only)[16] and Laguna Bell Corridor 230 kV line upgrades
- Interim operating procedure that includes closing Mesa 230 kV sectionalizing circuit breaker to connect Mesa North and South 230 kV buses. Utilizing this interim operating procedure will help provide interim mitigation to SCE-owned 230 kV transmission line's loading concern under overlapping contingency condition for the 2021 timeframe. The Mesa North and South 230 kV buses will need to be electrically separated due to high

[16] The Mesa 500 kV loop-in portion is delayed until March 2022.

short circuit duty concern when the Vincent-Mira Loma 500 kV line is looped into the Mesa Substation by March 2022. Looping the 500 kV line into the Mesa Substation provides another power source in the western LA Basin, as well mitigation to previously identified 230 kV transmission line loading constraint (i.e., Serrano corridor).

- Hassayampa – North Gila #2 500 kV Line (APS)
- Deployment of CPUC-approved preferred resources from the long-term procurement plan (R.12-03-014) for local capacity need in the western LA Basin sub-area (320 MW)
- Utilization of 460 MW of 20-minute demand response within SCE service area
- Retirement of 1,356 MW of the existing Redondo Beach OTC generation
- Alamitos repowering (640 MW)
- Retirement of 2,010 MW of the existing Alamitos OTC generation
- Huntington Beach repowering (644 MW)
- Retirement of 452 MW of the existing Huntington Beach OTC generation
- Completion of Stanton Energy Reliability Center (98 MW)

3.2.1.2 *El Nido Sub-area*

El Nido is Sub-area of the LA Basin LCR Area.

3.2.1.2.1 El Nido LCR Sub-area Diagram

Please refer to Figure 3.2-1 above.

3.2.1.2.2 El Nido LCR Sub-area Load and Resources

Table 3.2-2 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.

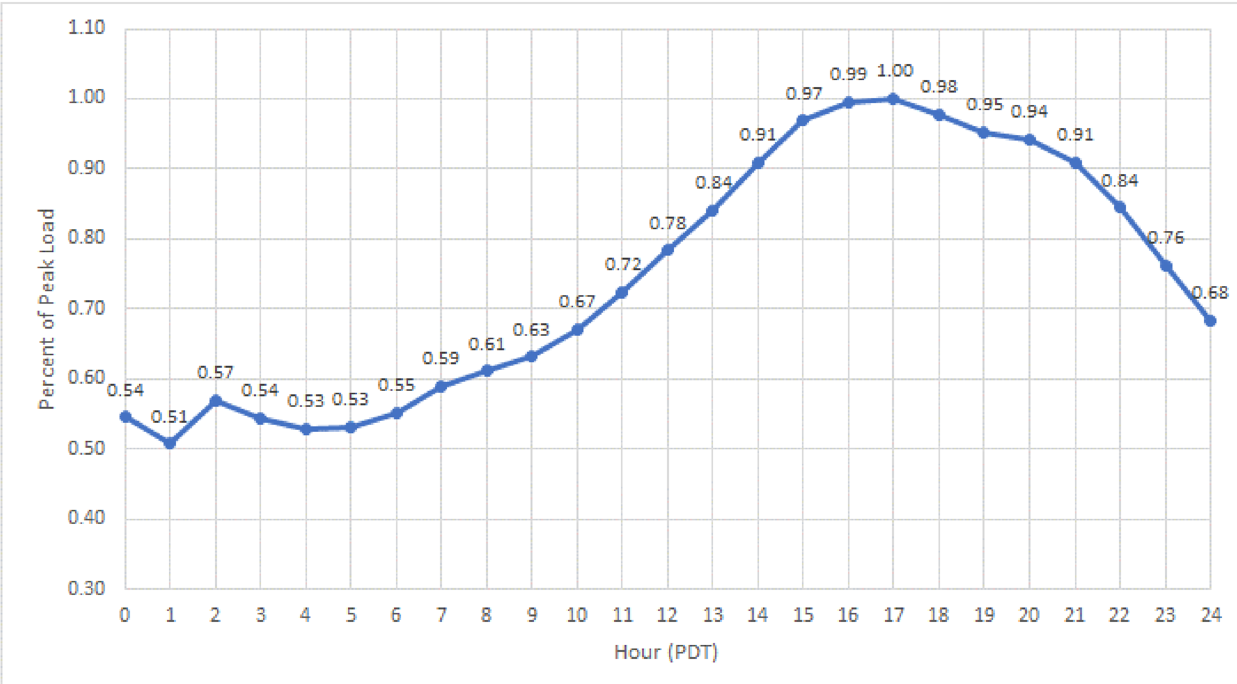
Table 3.2-2 El Nido LCR Sub-area 2021 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**NQC**	**At Peak**
Gross Load	1014	Market, Net Seller, Battery, Wind, Solar	536	536
AAEE	-17	MUNI	0	0
Behind the meter DG	-31	QF	0	0
Net Load	**966**	LTPP Preferred Resources	23	23
Transmission Losses	14	Existing 20-minute Demand Response	8	8
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**980**	**Total**	**567**	**567**

3.2.1.2.3 El Nido LCR Sub-area Hourly Profiles

Figure 3.2-2 illustrates the forecast 2021 profile for the summer peak day in the El Nido LCR Sub-area. The load profile is obtained from the CEC's SCE hourly demand forecast (CEDU 2018) for the 2018-2022 timeframe[17].

Figure 3.2-2 El Nido LCR Sub-area 2021 Peak Day Forecast Profiles



3.2.1.2.4 El Nido LCR Sub-area Requirement

Table 3.2-3 identifies the sub-area requirements. There is no Category B (Single Contingency) LCR requirement and the LCR requirement for Category C (Multiple Contingency) is 374 MW.

Table 3.2-3 El Nido LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First Limit	B	None	None	0
2021	First Limit	C	La Fresa-La Cienega 230 kV	La Fresa – El Nido #3 & #4 230 kV	374

[17] https://ww2.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

3.2.1.2.5 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 (G-219Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.1.3 *Western LA Basin Sub-area*

Western LA Basin is Sub-area of the LA Basin LCR Area.

3.2.1.3.1 Western LA Basin LCR Sub-area Diagram

Please refer to Figure 3.2-1 above.

3.2.1.3.2 Western LA Basin LCR Sub-area Load and Resources

Table 3.2-4 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 3.2-4 Western LA Basin Sub-area 2021 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**NQC**	**At Peak**
Gross Load	11,796	Market, Net Seller, Battery[18], Wind, Solar	3,369	3,369
AAEE	-188	MUNI	582	582
Behind the meter DG	-483	QF	58	58
Net Load	**11,125**	LTPP Preferred Resources	220	220
Transmission Losses	167	Existing 20-minute Demand Response	149	149
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**11,292**	**Total**	**4,378**	**4,378**

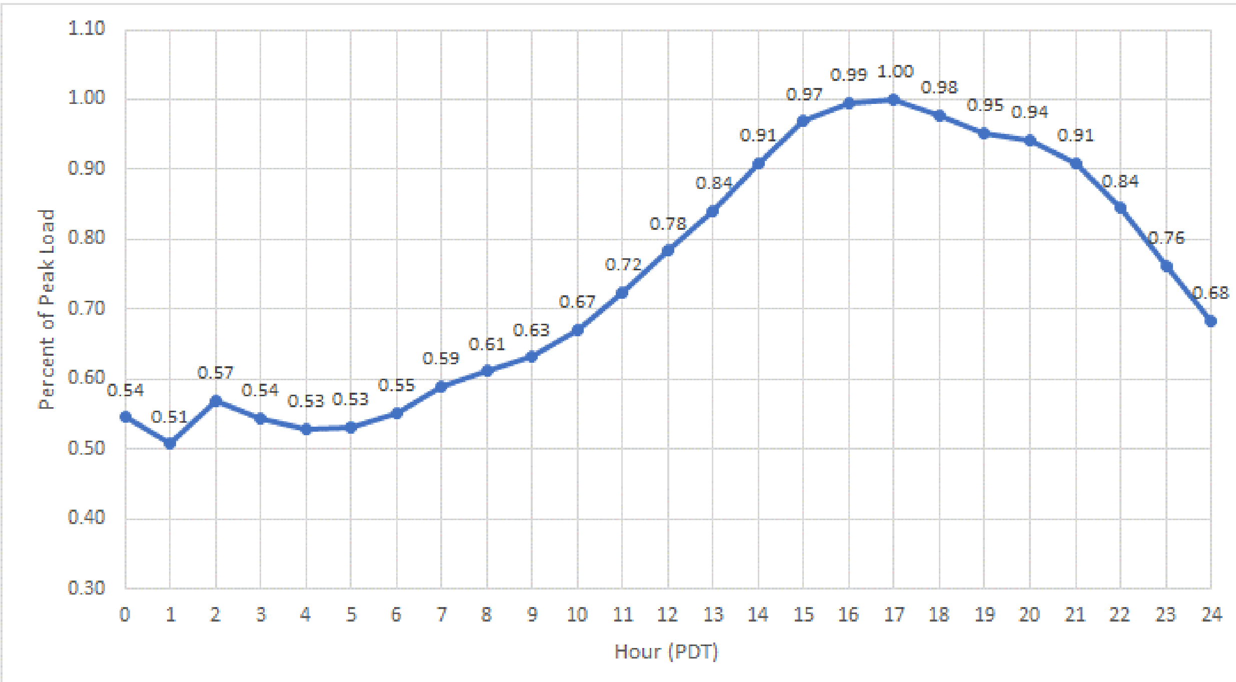
3.2.1.3.3 Western LA Basin LCR Sub-area Hourly Profiles

The load profile is obtained from the CEC's SCE hourly demand forecast (CEDU 2018) for the 2018-2022 timeframe.

[18] This includes battery energy storage system that has long-term procurement approved by the CPUC.

Figure 3.2-3 illustrates the forecast 2021 profile for the summer peak day in the Western LA Basin LCR Sub-area. The load profile is obtained from the CEC's SCE hourly demand forecast (CEDU 2018) for the 2018-2022 timeframe[19].

Figure 3.2-3 Western LA Basin LCR Sub-area 2021 Peak Day Forecast Profiles



3.2.1.3.4 Western LA Basin LCR Sub-area Requirement

Table 3.2-5 identifies the sub-area LCR requirements. The LCR requirement for Category B (Single Contingency) is non-binding and for Category C (Multiple Contingency) is 3,965 MW.

Table 3.2-5 Western LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First Limit	B	Non-binding	Multiple combinations possible	N/A

[19] https://ww2.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

2021	First Limit	C	San Onofre-San Luis Rey #1 230 kV line	San Onofre-San Luis Rey #2 230 kV, followed by San Onofre-San Luis Rey #3 230 kV line, or vice versa	3,965

3.2.1.3.5 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.

3.2.1.4 *West of Devers Sub-area*

West of Devers is a Sub-area of the LA Basin LCR Area. The 2021 local capacity study identified that the West of Devers Sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.2.1.5 *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.

3.2.1.6 *Valley Sub-area*

Valley-Devers is a Sub-area of the LA Basin LCR Area. The 2021 local capacity study identified that the Valley-Devers Sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.2.1.7 *Eastern LA Basin Sub-area*

Eastern LA Basin is Sub-area of the LA Basin LCR Area.

3.2.1.7.1 Eastern LA Basin LCR Sub-area Diagram

Please refer to Figure 3.2-1 above.

3.2.1.7.2 Eastern LA Basin LCR Sub-area Load and Resources

Table 3.2-6 provides the forecast load and resources in Eastern LA Basin LCR Sub-area in 2021. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.2-6 Eastern LA Basin Sub-area 2021 Forecast Load and Resources

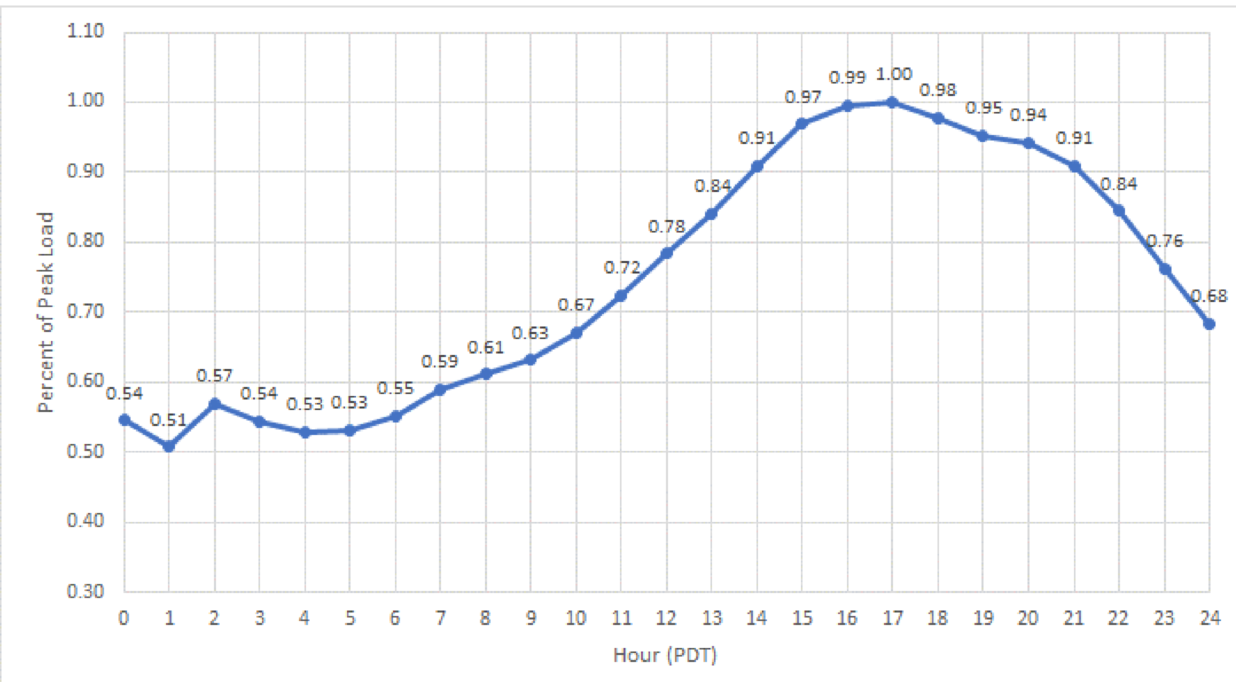
Load (MW)	Generation (MW)	NQC	At Peak

Gross Load	7,752	Market, Net Seller, Battery, Wind, Solar	2,706	2,706
AAEE	-87	MUNI	528	528
Behind the meter DG	-506	QF	177	177
Net Load	**7,159**	LTPP Preferred Resources	0	0
Transmission Losses	107	Existing 20-minute Demand Response	117	117
Pumps	0	Mothballed	335	335
Load + Losses + Pumps	**7266**	**Total**	**3,863**	**3,863**

3.2.1.7.3 Eastern LA Basin LCR Sub-area Hourly Profiles

Figure 3.2-4 illustrates the forecast 2021 profile for the summer peak day in the Eastern LA Basin LCR Sub-area. The load profile is obtained from the CEC's SCE hourly demand forecast (CEDU 2018) for the 2018-2022 timeframe[20].

Figure 3.2-4 Eastern LA Basin LCR Sub-area 2021 Peak Day Forecast Profiles



Eastern LA Basin LCR Sub-area Requirement

Table 3.2-7 identifies the sub-area LCR requirements. The LCR requirement for Category B (Single Contingency) is non-binding and for Category C (Multiple Contingency) is 2,282 MW.

[20] https://ww2.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

Table 3.2-7 Eastern LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First Limit	B	Non-binding	Multiple combinations possible	N/A
2021	First Limit	C	Post transient voltage stability	Serrano-Valley 500 kV, followed by Devers–Red Bluff #1 and #2 500 kV	2,282

3.2.1.7.4 Effectiveness factors:

All units within the Eastern LA Basin Sub-area have the same effectiveness factor.

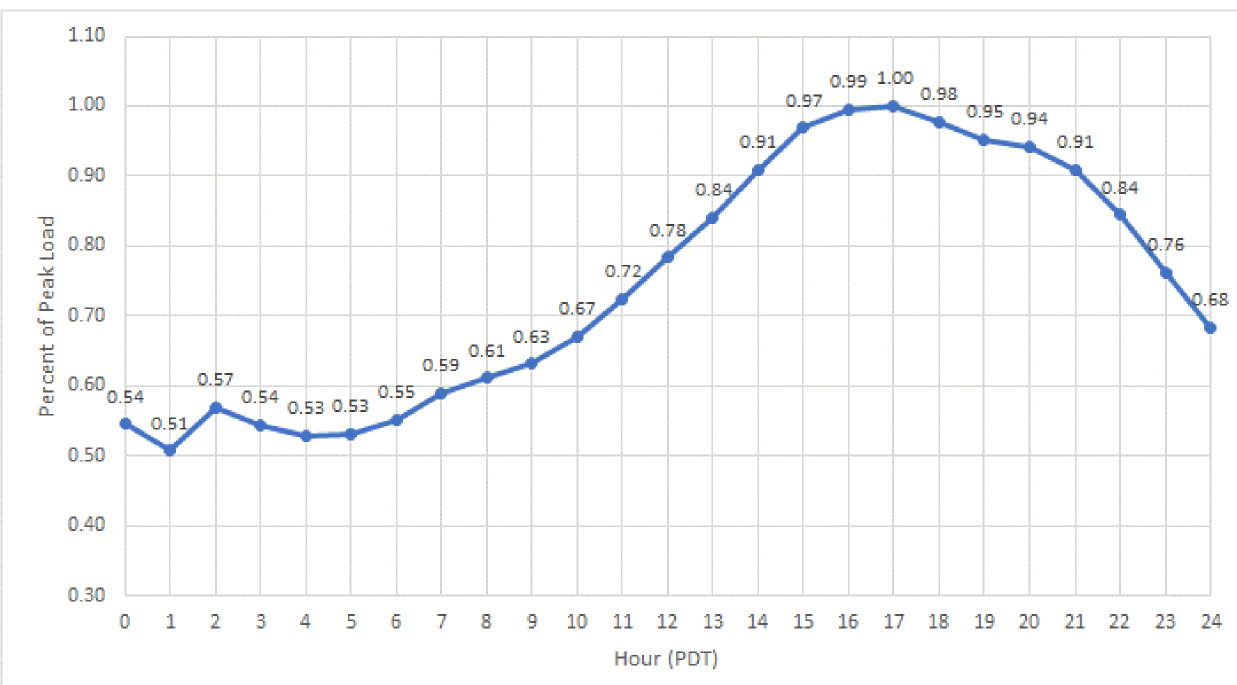
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7630 (G-219Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

3.2.1.8 *LA Basin Overall*

3.2.1.8.1 LA Basin LCR Sub-area Hourly Profiles

Figure 3.2-5 illustrates the forecast 2021 profile for the summer peak day in the LA Basin LCR area.

Figure 3.2-5 LA Basin LCR area 2021 Peak Day Forecast Profiles



3.2.1.8.2 LA Basin LCR area Requirement

Table 3.2-8 identifies the area requirements. The LCR requirement for Category B requirement (Single Contingency) is 5,946 MW and for Category C (Multiple Contingency) is 6,246 MW, based on the most recent adopted 2018-2030 California Energy Demand Update (CEDU) forecast. For sensitivity assessment with higher demand forecast, please see the following section 3.2.1.8.5.

Table 3.2-8 LA Basin LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First Limit	B	Imperial Valley-El Centro 230 kV line (S line)	G-1 of TDM, system readjustment, followed by the Imperial Valley–North Gila 500 kV line	5,946
2021	First Limit	C	San Onofre-San Luis Rey #1 230 kV line	San Onofre-San Luis Rey #2 230 kV, followed by San Onofre-San Luis Rey #3 230 kV line, or vice versa	6,246

3.2.1.8.3 Effectiveness factors:

See Attachment B - Table titled LA Basin.

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

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.

3.2.1.8.4 Changes compared to 2020 LCT study

For the baseline LCR studies, the 2021 load forecast, when compared with the 2020, is slightly higher by about 69 MW. The LCR need is decreased by 1,118 MW, primarily due to the following changes in transmission topology in the SCE service area:

- The series capacitors on the Eldorado-Lugo 500 kV and the Lugo-Mohave 500 kV lines are returned to service after upgrades are completed. Placing the series capacitors on-line facilitates flows into SCE system from the eastern system and helps to relieve loading on the S line under contingency condition. The Eldorado-Lugo and Lugo-Mohave 500 kV series capacitors are scheduled to be bypassed in 2020 to enable the upgrades on the series capacitors. This work is scheduled to be completed by 6/30/2021.
- The 230 kV loop-in portion of the Mesa loop-in project has been confirmed as expected to be completed prior to June 1, 2021 and therefore is modeled in the study. In addition, the North and South Mesa 230 kV buses are electrically connected via closing the sectionalizing circuit breaker on an interim basis until the Vincent-Mira Loma 500 kV line loop-in is completed in March 2022.
- Additionally to the above transmission topology changes, there are also additional resources (i.e., 70 MW of new battery energy storage system) in the San Diego area. It is more effective to dispatch resources in San Diego area to mitigate the S line contingency loading concern, located in the southern SDG&E and IID's transmission system, than dispatching less effective resources in the LA Basin for mitigation.

As a result of completion of the series capacitor upgrades and returning the Eldorado-Lugo and Lugo-Mohave 500 kV line series capacitors to service, the transmission constraint that drives the overall LA Basin LCR need changes from the S line constraint to the San Onofre-San Luis Rey #1 230 kV line thermal loading limit under an overlapping N-1-1 contingency. With the completion of the Mesa 500 kV line loop-in work scheduled to be completed by March 2022, more southbound flows from SCE northern transmission system will help offset the northbound flow on the San Onofre-San Luis Rey 230 kV lines, thus helping to reduce the SDG&E's 230-kV line loading concern.

3.2.1.8.5 Sensitivity study with higher demand forecast for SCE

The ISO has also conducted a sensitivity study to assess the risk associated with forecast uncertainty, given that these studies will ultimately be updated with the latest forecast information in the normal course of the 2021 Local Capacity Technical Study efforts in the spring of 2020. There were two scenarios evaluated for this sensitivity study.

Table 3.2-9 provides a summary the local capacity requirements for the sensitivity study:

1. **Scenario 1 –** Using the higher sensitivity demand forecast for SCE (i.e., 800 MW higher[21])

[21] 800 MW is the difference between the 2018 IEPR and the 2017 IEPR demand forecast for SCE for 2021.

The local capacity requirements for the LA Basin and the Western LA Basin for Scenario 1 are 7,102 MW and 4,800 MW, respectively. The western LA Basin is deficient by about 422 MW. However, it would require more than this amount to mitigate the loading concern because required resources are not located immediately on the loadside of where the loading concern is located. In this case, it requires dispatch of 476 MW of the existing Alamitos OTC generating units, as well as other non-OTC generating units, to mitigate identified contingency loading concern. Since the OTC implementation date for these units is currently December 31, 2020, dispatching Alamitos OTC generation would require an extension of the OTC implementation date for 2021. Dispatching Alamitos OTC generation is effective in mitigating the identified loading concern because the overloaded lines connect SDG&E system with SCE's southern portion of the western LA Basin.

2. **Scenario 2 –** Scenario 1 plus unavailability of 360 MW of "at-risk-of-retirement" generation

   For this sensivitity assessment, the ISO utilized the sensitivity higher load that was used in the Scenario #1, as well as assuming 360 MW of "at-risk-of-retirement" generation being unavailable. This 360 MW of "at-risk-of-retirement" generation assumption includes 260 MW of generation that was previously assumed to be retired in the CPUC's Long-Term Procurement Plan Track 4 Study (Rulemaking 12-03-014), as well as 100 MW of generation that was previously placed on mothballed status until the units recently became available again in 2019 due to a recent annual power contract with SCE.

   For this sensitivity study, the ISO removed this 360 MW "at-risk-of-retirement" generation from the power flow model to determine the required capacity from Alamitos OTC generation. The capacity need for Alamitos OTC extension was determined to be in the amount of about 816 MW if 360 MW of "at-risk-of-retirement" non-OTC generation were unavailable.

Table 3.2-9 Summary of Study Results for the Sensitivity Study

Year	Limit	Category	Area	Limiting Facility	Contingency	Scenario 1: LCR Need / (Deficiency)[22] (MW)	Scenario 1: Alamitos OTC Generation Need (MW)	Scenario 2: LCR Need / (Deficiency) (MW)	Scenario 2: Alamitos OTC Generation Need (MW)
2021	First Limit	C	LA Basin	San Onofre-San Luis Rey #1 230 kV line	San Onofre-San Luis Rey #2 230 kV, followed by San Onofre-San Luis Rey #3 230 kV line, or vice versa	7,102 (422)[23]	476	7,082 (762)[24]	816
2021	First Limit	C	Western LA Basin Subarea	San Onofre-San Luis Rey #1 230 kV line	San Onofre-San Luis Rey #2 230 kV, followed by San Onofre-San Luis Rey #3 230 kV line, or vice versa	4,800 (422)*	476	4,780 (762)*	816

3.2.2 San Diego-Imperial Valley Area

3.2.2.1 *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 #1 and #2 230 kV 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

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[22] If there is deficiency, the deficient amount is expressed as (XX) MW

[23] The overall LA Basin is also identified as having deficiency because the western LA Basin is its subarea and is identified as having deficiencies in the sensitivity studies.

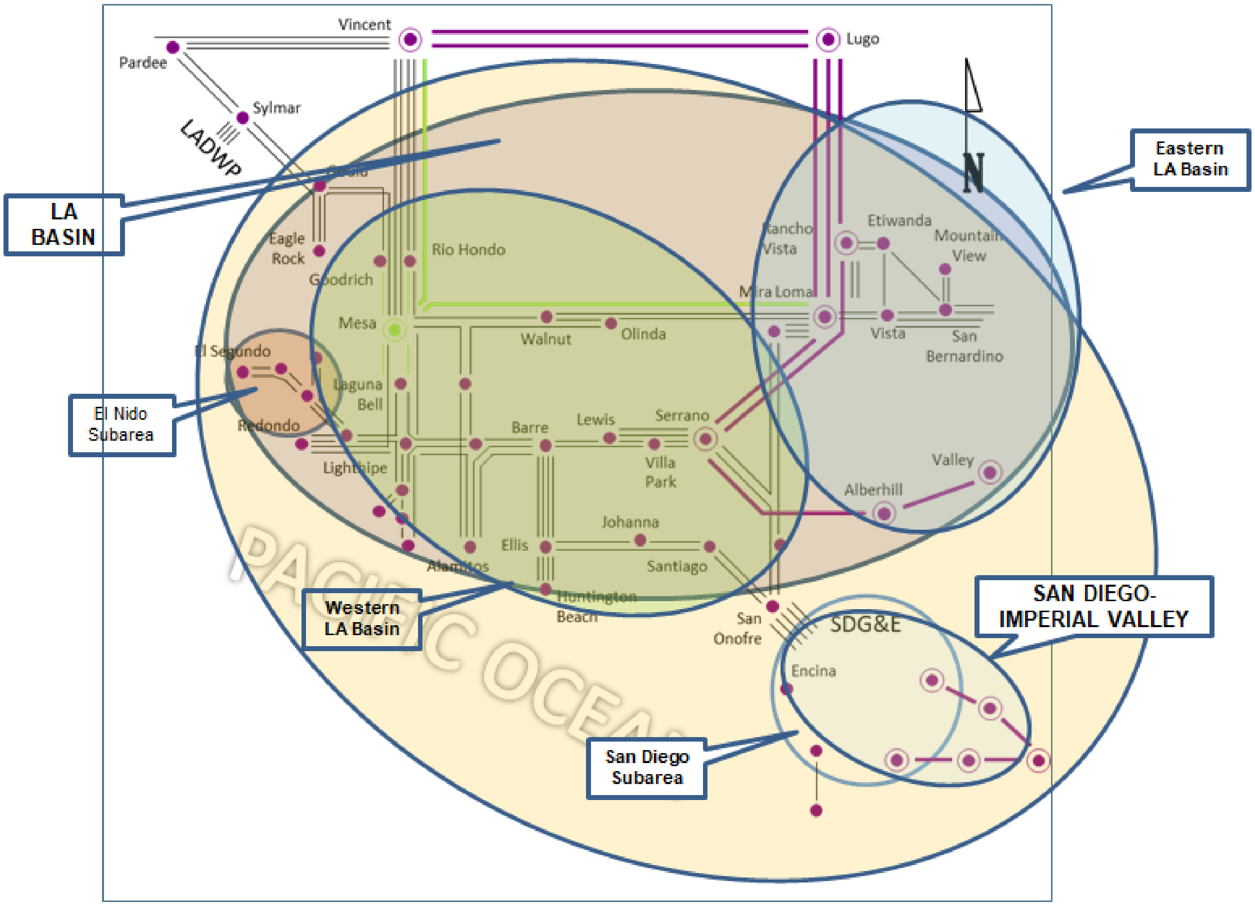
[24] For Scenario 2, the deficiency includes 360 MW of unavailable "at-risk-of-retirement" generation (i.e., total available capacity is reduced by the assumption of this unavailable generation).

* See footnote above

- 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
- Imperial Valley is in El Centro is out
- Imperial Valley is in La Rosita is out

3.2.2.1.1 San Diego-Imperial Valley LCR Area Diagram

Figure 3.2-6 San Diego-Imperial Valley LCR Area



3.2.2.1.2 San Diego-Imperial Valley LCR Area Load and Resources

Table 3.2-10 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) on September 1st.

At the local area peak time the estimated, behind the meter, solar output is 0.00%.

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 3.2-10 San Diego-Imperial Valley LCR Area 2021 Forecast Load and Resources

Load (MW)		Generation (MW)	NQC	At Peak
Gross Load	4,663	Market, Net Seller, Battery, Wind	4,016	4,016
AAEE	-159	Solar	523	0
Behind the meter DG	0	QF	4	4

Net Load	**4,504**	LTPP Preferred Resources	0	0
Transmission Losses	101	Existing 20-minute Demand Response	16	16
Synchronous condenser loads	30	Mothballed	0	0
Load + Losses + Pumps	**4,635**	**Total**	**4,559**	**4,036**

3.2.2.1.3 Approved transmission projects modeled:

- Ocean Ranch 69 kV substation
- Mesa Height TL600 Loop-in
- Re-conductor of Mission-Mesa Heights 69 kV
- Re-conductor of Kearny-Mission 69 kV line
- TL6906 Mesa Rim Rearrangement
- Upgrade Bernardo - Rancho Carmel 69 kV line
- Re-conductor of Japanese Mesa–Baseline–Talega Tap 69 kV lines
- 2nd Miguel–Bay Boulevard 230 kV line
- 2nd Mission 230/69 kV bank
- Suncrest SVC project
- By-passing 500 kV series capacitor banks on the Southwest Powerlink, Sunrise Powerlink and the Imperial Valley-North Gila 500 kV lines
- Generation retirements at Encina, North Island, and Division Naval Station)
- Carlsbad Energy Center (Encina repower) (5x100 MW)
- Battery energy storage projects (total of 183 MW) at various locations
- TL632 Granite loop-in and TL6914 reconfiguration
- 2nd Poway–Pomerado 69 kV line
- Imperial Valley bank #80 replacement

3.2.2.2 *San Diego Sub-area*

San Diego is Sub-area of the San Diego-Imperial Valley LCR Area.

3.2.2.2.1 San Diego LCR Sub-area Diagram

Please refer to

Figure 3.2-6 above.

3.2.2.2.2 San Diego LCR Sub-area Load and Resources

Table 3.2-11 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 3.2-11 San Diego Sub-area 2021 Forecast Load and Resources

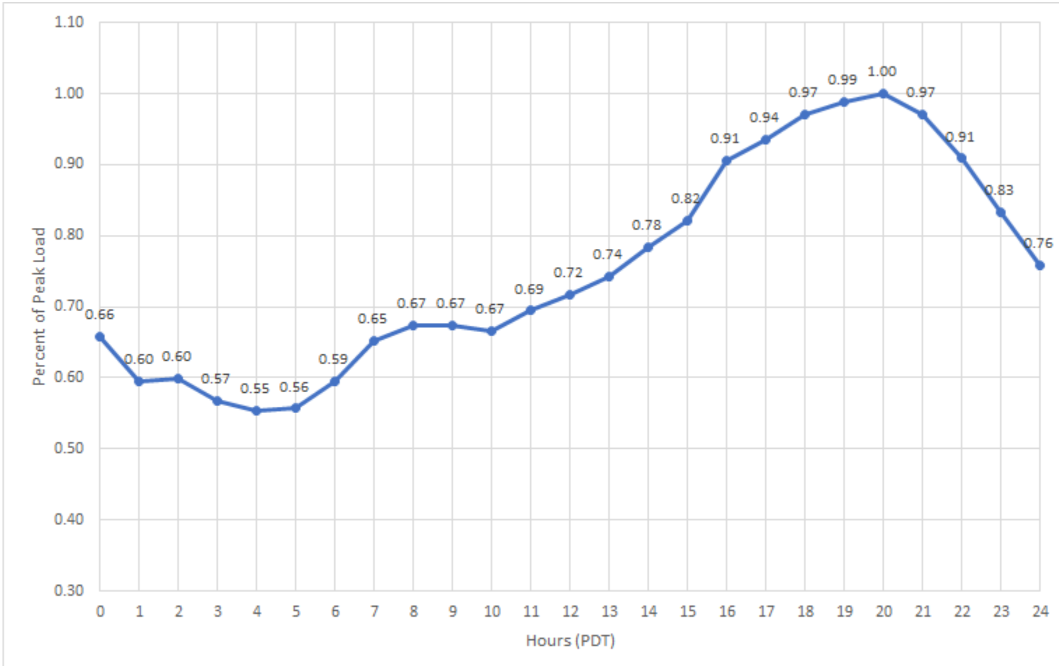
Load (MW)		**Generation (MW)**	**NQC**	**At Peak**
Gross Load	4,663	Market, Net Seller, Battery, Wind	2,881	2,881
AAEE	-159	Solar	23	0
Behind the meter DG	0	QF	4	4
Net Load	**4,504**	LTPP Preferred Resources	0	0
Transmission Losses	101	Existing 20-minute Demand Response	16	16
Synchronous condenser loads	30	Mothballed	0	0
Load + Losses + Pumps	**4,635**	**Total**	**2,924**	**2,901**

3.2.2.2.3 San Diego LCR Sub-area Hourly Profiles

Figure 3.2-7 illustrates the forecast 2021 profile for the summer peak day for the San Diego LCR Sub-area. The load profile is obtained from the CEC's SDG&E hourly demand forecast (CEDU 2018) for the 2018-2022 timeframe[25].

[25] https://ww2.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

Figure 3.2-7 San Diego LCR Sub-area 2021 Peak Day Forecast Profiles



3.2.2.2.4 San Diego Bulk Sub-area Requirement

Table 3.2-12 identifies the sub-area LCR requirements. The Category B (Single Contingency) LCR requirement is non-binding and the LCR requirement for Category C (Multiple Contingency) is 2,443 MW.

Table 3.2-12 San Diego LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First Limit	B	Non-binding	Multiple combinations possible.	N/A
2021	First Limit	C	Remaining Sycamore – Suncrest 230 kV	ECO – Miguel 500 kV, system readjustment followed by one of the Sycamore – Suncrest 230 kV lines	2,443

3.2.2.2.5 Effectiveness factors:

See Attachment B - Table titled San Diego.

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

3.2.2.3 *San Diego-Imperial Valley Overall*

3.2.2.3.1 San Diego-Imperial Valley LCR area Hourly Profiles

Same as San Diego Sub-area see section above.

3.2.2.3.2 San Diego-Imperial Valley LCR area Requirement

Table 3.2-13 identifies the area LCR requirements. The LCR requirement for Category B (Single Contingency) and Category C (Multiple Contingency) is the same 3,944 MW.

Table 3.2-13 San Diego-Imperial Valley LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2021	First Limit	B/C	El Centro 230/92 kV	TDM, system readjustment and Imperial Valley–North Gila 500 kV, or vice versa	3,944

3.2.2.3.3 Effectiveness factors:

See Attachment B - Table titled San Diego.

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

3.2.2.3.4 Changes compared to 2020 local capacity study

Compared with the 2020 local capacity study, the modeled demand for the 2021 is slightly higher by about 22 MW. The overall LCR need for the San Diego – Imperial Valley area increases by about 49 MW, mainly due to slightly higher load as well as due using all available resources that are more effective in mitigating the critical reliability concern for the overall local capacity area. Using more effective resources that are available help reduce the overall LCR requirements.

3.3 Results and Recommendations

The following summary includes major findings related to the need for Alamitos OTC implementation schedule extension from this 2021 local capacity study:

1. Study results based on the most recent CEC-adopted 2018-2030 California Energy Demand Update (CEDU) Forecast from the 2018 Integrated Energy Policy Report (IEPR) process for the baseline LCR study do not trigger the need for Alamitos OTC implementation schedule extension. The lower demand forecast, coupled with partial completion of the Mesa Loop-in Project (i.e., completion of the 230-kV loop-in portion of the project), as well as completion of the Lugo-Mohave and Lugo-Eldorado 500 kV line series capacitors and returning them to service[26] help reduce the local capacity requirements in the LA Basin from previous study results.
2. The ISO has also conducted a ***sensitivity*** study to assess the risk associated with forecast uncertainty, given that these studies will ultimately be updated with the latest forecast information in the normal course of the 2021 Local Capacity Technical Study efforts in the spring of 2020. There were two scenarios evaluated for this sensitivity study:
   a. A scenario based on approximately 800 MW higher load across the SCE service territory. This demonstrated a need for Alamitos OTC generation of 476 MW;
   b. A second incorporating the higher demand forecast in the first scenario, but evaluated without the use of 360 MW of non-OTC "at-risk-of-retirement" generation.[27] For this scenario, the capacity need for Alamitos OTC extension increased to about 816 MW.

Note that Alamitos Units 1, 2 and 6 are scheduled to be retired by the end of 2019 to allow for transfer of emission credits to the new repowering 640 MW Alamitos combined cycle generating facility. This will leave only three remaining OTC units on site: Units 3 (320 MW), 4 (320 MW) and 5 (480 MW) for OTC schedule extension consideration.

The CAISO also notes that in the CPUC Assigned Commissioner and Administrative Law Judge Ruling of June 20, 2019, in Rulemaking 16-02-007, the option of "Extending deadlines for some portion of planned OTC retirements until new procurement is authorized or online"[28] was proposed to mitigate against potential system-wide capacity shortages beginning in 2021. Further, the Ruling suggested "that the appropriate individuals within staff of the Commission begin discussions through appropriate channels with the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) to the State Water Resources Control Board (Water Board), under whose jurisdiction the OTC retirements are set"[29], regarding potentially postponing the retirement of one or more OTC units by a year or two.

In light of the inherent forecast risk and the sensitivity of the local capacity requirement results for the need for Alamitos to load forecast levels, as well as the potential need for extension of OTC compliance for system capacity, the CAISO considers it prudent to commence activities seeking

[26] The Lugo-Mohave and Lugo-Eldorado 500 kV line series capacitors are bypassed while they are being upgraded in 2020 timeframe.

[27] 260 MW of this generation was assumed to be retired as part of the Scoping Ruling from the CPUC Long-Term Procurement Plan (LTPP) Track 4 Study (Rulemaking 12-03-014) due to age of the generation before its refurbishment; the other 100 MW generation had mothballed status previously but withdrew its mothball request in Q4 2018 after securing a power contract with SCE.

[28] Page 14, CPUC Assigned Commissioner and Administrative Law Judge Ruling of June 20, 2019, in Rulemaking 16-02-007, Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements

[29] Page 15*, id*

an extension to the OTC compliance date for Alamitos at this time. Actual procurement levels would depend on the 2021 local capacity technical study requirements developed early in 2020, or, possibly, by the need for system capacity determined by the CPUC.

Attachment A – List of physical resources by PTO, local area and market ID

SCE	ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	0.00	1	LA Basin	Western	Retired by 12/31/2019	Market
SCE	ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	0.00	2	LA Basin	Western	Retired by 12/31/2019	Market
SCE	ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	0.00	3	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	0.00	4	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	0.00	5	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	0.00	6	LA Basin	Western	Retired by 12/31/2019	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	52.07	1	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24012	ARCO 2G	13.8	52.07	2	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24013	ARCO 3G	13.8	52.07	3	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24014	ARCO 4G	13.8	52.07	4	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24163	ARCO 5G	13.8	26.03	5	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24164	ARCO 6G	13.8	26.03	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

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

SCE	BLAST_1_WIND	24839	BLAST	115	12.99	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	BUCKWD_1_NPALM1	25634	BUCKWIND	115	0.98		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	BUCKWD_1_QF	25634	BUCKWIND	115	4.37	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.35	W5	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CABZON_1_WINDA1	29290	CABAZON	33	10.87	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CAPWD_1_QF	25633	CAPWIND	115	5.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	CENTER_2_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	47.00	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	4.61	1	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	4.61	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				0.58		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				0.41		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	25.51	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	CHINO_6_SMPPAP	24140	SIMPSON	13.8	22.78	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				0.62		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR2				0.72		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR3				0.51		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR4				0.53		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR5				0.41		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR6				0.82		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	25632	TERAWND	115	8.63	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_QF	25639	SEAWIND	115	10.35	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_SEPV05				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_1_SOLAR				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	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	1.64	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	25648	DVLCYN1G	13.8	39.40	1	LA Basin	Eastern	Aug NQC	MUNI

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

SCE	DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	39.40	2	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	52.54	3	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	52.54	4	LA Basin	Eastern	Aug NQC	MUNI
SCE	ELLIS_2_QF	24325	ORCOGEN	13.8	0.04	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	0.22		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_2_RTS010	24055	ETIWANDA	66	0.62		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS015	24055	ETIWANDA	66	1.23		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS017	24055	ETIWANDA	66	1.44		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS018	24055	ETIWANDA	66	0.62		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS023	24055	ETIWANDA	66	1.03		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS026	24055	ETIWANDA	66	2.46		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS027	24055	ETIWANDA	66	0.82		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	16.88	1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	46.00	1	LA Basin	Eastern		Market
SCE	ETIWND_6_MWDETI	25422	ETI MWDG	13.8	5.94	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

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

SCE	GARNET_1_SOLAR2	24815	GARNET	115	1.64		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Solar
SCE	GARNET_1_UNITS	24815	GARNET	115	2.06	G1	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.71	G2	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	1.61	G3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_WIND	24815	GARNET	115	1.72		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_1_WINDS	24815	GARNET	115	5.96	W2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_1_WT3WND	24815	GARNET	115	0.00	W3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_DIFWD1	24815	GARNET	115	2.09		LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_HYDRO	24815	GARNET	115	0.80	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_WIND1	24815	GARNET	115	2.97		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND2	24815	GARNET	115	3.10		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND3	24815	GARNET	115	3.34		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND4	24815	GARNET	115	2.60		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND5	24815	GARNET	115	0.80		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WPMWD6	24815	GARNET	115	1.57		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

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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	14.78	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.78	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_LBECH1	24170	LBEACH12	13.8	65.00	1	LA Basin	Western		Market
SCE	HINSON_6_LBECH2	24170	LBEACH12	13.8	65.00	2	LA Basin	Western		Market
SCE	HINSON_6_LBECH3	24171	LBEACH34	13.8	65.00	3	LA Basin	Western		Market
SCE	HINSON_6_LBECH4	24171	LBEACH34	13.8	65.00	4	LA Basin	Western		Market
SCE	HINSON_6_SERRGN	24139	SERRFGEN	13.8	28.93	D1	LA Basin	Western	Aug NQC	Market
SCE	HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	0.00	1	LA Basin	Western	Retired by 12/31/2019	Market
SCE	HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	0.00	2	LA Basin	Western	Retired by 2021	Market
SCE	INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Market
SCE	INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	LA Basin	Eastern, Valley, Valley-Devers	Mothballed	Market
SCE	LACIEN_2_VENICE	24337	VENICE	13.8	0.00	1	LA Basin	Western, El Nido	Aug NQC	MUNI
SCE	LAGBEL_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				1.70		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_LNDFL				1.23		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				2.26		LA Basin	Eastern	Not modeled Aug NQC	Market

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SCE	MIRLOM_2_RTS032				0.62		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS033				0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_TEMESC				1.07		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	5.00		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.04	1	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.04	2	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.04	3	LA Basin	Eastern	Aug NQC	Market
SCE	MTWIND_1_UNIT 1	29060	MOUNTWND	115	11.77	S1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 2	29060	MOUNTWND	115	5.88	S2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 3	29060	MOUNTWND	115	5.95	S3	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	OLINDA_2_COYCRK	24211	OLINDA	66	3.13		LA Basin	Western	Not modeled	QF/Selfgen
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.07	C1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.07	C2	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.07	C3	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.07	C4	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	7.28	S1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_QF	24211	OLINDA	66	0.01		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	OLINDA_7_BLKSND	24211	OLINDA	66	0.41		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	2.74		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	PADUA_6_QF	24111	PADUA	66	0.38		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	7.95	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	PWEST_1_UNIT	24815	GARNET	115	0.56	PC	LA Basin	Western	Aug NQC	Market
SCE	REDOND_7_UNIT 5	24121	REDON5 G	18	0.00	5	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 6	24122	REDON6 G	18	0.00	6	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 7	24123	REDON7 G	20	0.00	7	LA Basin	Western	Retired by 12/31/2019	Market
SCE	REDOND_7_UNIT 8	24124	REDON8 G	20	0.00	8	LA Basin	Western	Retired by 2021	Market
SCE	RENWD_1_QF	25636	RENWIND	115	1.33	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RENWD_1_QF	25636	RENWIND	115	1.32	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		LA Basin	Western	Not modeled Aug NQC	Net Seller
SCE	RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	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	3.08		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	42.00	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	SANTGO_2_LNDFL1	24341	COYGEN	13.8	19.16	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	4.11	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SANWD_1_QF	25646	SANWIND	115	4.11	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SBERDO_2_PSP3	24921	MNTV-CT1	18	140.56	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP3	24922	MNTV-CT2	18	140.56	1	LA Basin	Eastern, West of Devers		Market

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SCE	SBERDO_2_PSP3	24923	MNTV-ST1	18	243.89	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24924	MNTV-CT3	18	140.56	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24925	MNTV-CT4	18	140.56	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24926	MNTV-ST2	18	243.89	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_QF	24214	SANBRDNO	66	0.26		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_2_REDLND	24214	SANBRDNO	66	0.82		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS005	24214	SANBRDNO	66	1.03		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS007	24214	SANBRDNO	66	1.03		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS011	24214	SANBRDNO	66	1.44		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS013	24214	SANBRDNO	66	1.44		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS016	24214	SANBRDNO	66	0.62		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	0.32		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_6_MILLCK	24214	SANBRDNO	66	1.04		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SENTNL_2_CTG1	29101	SENTINEL_G 1	13.8	103.76	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG2	29102	SENTINEL_G 2	13.8	95.34	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG3	29103	SENTINEL_G 3	13.8	96.85	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG4	29104	SENTINEL_G 4	13.8	102.47	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG5	29105	SENTINEL_G 5	13.8	103.81	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG6	29106	SENTINEL_G 6	13.8	100.99	1	LA Basin	Eastern, Valley-Devers		Market

SCE	SENTNL_2_CTG7	29107	SENTINEL_G 7	13.8	97.06	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG8	29108	SENTINEL_G 8	13.8	101.80	1	LA Basin	Eastern, Valley-Devers		Market
SCE	TIFFNY_1_DILLON	29021	WINTEC6	115	11.93	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TRNSWD_1_QF	25637	TRANWIND	115	10.33	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TULEWD_1_TULWD1				33.81		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	3.50		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_RTS044	24160	VALLEYSC	115	3.28		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
SCE	VALLEY_5_SOLAR1	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Energy Only	Solar
SCE	VALLEY_5_SOLAR2	25082	WDT786	34.5	8.20	EQ	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Solar
SCE	VENWD_1_WIND1	25645	VENWIND	115	2.50	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND2	25645	VENWIND	115	4.25	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND3	25645	VENWIND	115	5.05	EU	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VERNON_6_GONZL1	24342	FEDGEN	13.8	5.75	1	LA Basin	Western		MUNI
SCE	VERNON_6_GONZL2	24342	FEDGEN	13.8	5.75	1	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	LA Basin	Western		MUNI
SCE	VILLPK_2_VALLYV	24216	VILLA PK	66	4.10	DG	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	VILLPK_6_MWDYOR	24216	VILLA PK	66	3.99		LA Basin	Western	Not modeled Aug NQC	MUNI
SCE	VISTA_2_RIALTO	24901	VSTA	230	0.41		LA Basin	Eastern	Not modeled	Market
SCE	VISTA_2_RTS028	24901	VSTA	230	1.44		LA Basin	Eastern	Not modeled Aug NQC	Market

SCE	VISTA_6_QF	24902	VSTA	66	0.06		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	WALCRK_2_CTG1	29201	WALCRKG1	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG2	29202	WALCRKG2	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG3	29203	WALCRKG3	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG4	29204	WALCRKG4	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG5	29205	WALCRKG5	13.8	96.65	1	LA Basin	Western		Market
SCE	WALNUT_2_SOLAR				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	WALNUT_6_HILLGEN	24063	HILLGEN	13.8	39.44	D1	LA Basin	Western	Aug NQC	Net Seller
SCE	WALNUT_7_WCOVCT	24157	WALNUT	66	3.45		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WALNUT_7_WCOVST	24157	WALNUT	66	5.61		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WHTWTR_1_WINDA1	29061	WHITEWTR	33	16.30	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	ZZ_ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	Net Seller
SCE	ZZ_HINSON_6_QF	24064	HINSON	66	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZ_LAFRES_6_QF	24332	PALOGEN	13.8	0.00	D1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24327	THUMSGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24329	MOBGEN2	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24330	OUTFALL1	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24331	OUTFALL2	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	29260	ALTAMSA4	115	0.00	1	LA Basin	Eastern, Valley-Devers	No NQC - hist. data	Wind
SCE	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

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SCE	ZZZ_New	24575	ALMT CTG1	18	200.00	G1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	24580	HUNTBCH CTG1	18	202.00	G1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	24576	ALMT CTG2	18	200.00	G2	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	24581	HUNTBCH CTG2	18	202.00	G2	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	24577	ALMT STG	18	240.00	S1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZ_New	24582	HUNTBCH STG	18	240.00	S1	LA Basin	Western	No NQC - Pmax	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	Aug NQC	QF/Selfgen
SCE	ZZZZZ_ETIWND_7_MIDVLY	24055	ETIWANDA	66	0.00		LA Basin	Eastern	Not modeled Aug NQC	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_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	Aug NQC	QF/Selfgen
SCE	ZZZZZ_RHONDO_2_QF	24213	RIOHONDO	66	0.00	DG	LA Basin	Western	Aug NQC	QF/Selfgen
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	Not modeled Aug NQC	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	48.00	1	SD-IV	San Diego, Border		Market
SDG&E	BREGGO_6_DEGRSL	22085	BORREGO	12.5	2.58	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	BREGGO_6_SOLAR	22082	BR GEN1	0.21	10.66	1	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CARLS1_2_CARCT1	22783	EA5 REPOWER1	13.8	100	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22784	EA5 REPOWER2	13.8	100	1	SD-IV	San Diego	Aug NQC	Market

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SDG&E	CARLS1_2_CARCT1	22786	EA5 REPOWER4	13.8	100	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22788	EA5 REPOWER3	13.8	100	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS2_1_CARCT1	22787	EA5 REPOWER5	13.8	100	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CCRITA_7_RPPCHF	22124	CHCARITA	138	2.31	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CHILLS_1_SYCENG	22120	CARLTNHS	138	0.71	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	CHILLS_7_UNITA1	22120	CARLTNHS	138	1.52	2	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	CNTNLA_2_SOLAR1	23463	DW GEN3&4	0.33	51.25	1	SD-IV		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	5.88	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	31.66	G1	SD-IV		Aug NQC	Solar
SDG&E	CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	25.33	G2	SD-IV		Aug NQC	Solar
SDG&E	CRELMN_6_RAMON1	22152	CREELMAN	69	0.82	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMON2	22152	CREELMAN	69	2.05	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMSR3				1.42		SD-IV	San Diego	Not modeled Aug NQC	Solar
SDG&E	CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	13.25	1	SD-IV	San Diego	Aug NQC	Wind
SDG&E	CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.315	26.65	G1	SD-IV		Aug NQC	Solar
SDG&E	CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.315	26.65	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	41.10	G1	SD-IV		Aug NQC	Wind
SDG&E	ESCNDO_6_EB1BT1	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego, Esco		Battery
SDG&E	ESCNDO_6_EB2BT2	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego, Esco		Battery
SDG&E	ESCNDO_6_EB3BT3	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego, Esco		Battery
SDG&E	ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	1	SD-IV	San Diego, Esco		Market
SDG&E	ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.00	1	SD-IV	San Diego, Esco		Market
SDG&E	ESCO_6_GLMQF	22332	GOALLINE	69	36.41	1	SD-IV	San Diego, Esco	Aug NQC	Net Seller
SDG&E	IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	82.00	1	SD-IV		Aug NQC	Solar
SDG&E	IVWEST_2_SOLAR1	23155	DU GEN1 G1	0.2	33.27	G1	SD-IV		Aug NQC	Solar

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SDG&E	IVWEST_2_SOLAR1	23156	DU GEN1 G2	0.2	28.23	G2	SD-IV		Aug NQC	Solar
SDG&E	JACMSR_1_JACSR1	23352	ECO GEN2	0.55	8.20	1	SD-IV		Aug NQC	Solar
SDG&E	LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	SD-IV	San Diego, Esco		Market
SDG&E	LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	SD-IV	San Diego, Esco		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	22996	INTBST	18	145.19	1	SD-IV			Market
SDG&E	LAROA2_2_UNITA1	22997	INTBCT	16	176.81	1	SD-IV			Market
SDG&E	LILIAC_6_SOLAR	22404	LILIAC	69	1.23	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	4.37	1	SD-IV	San Diego, Mission	Aug NQC	Market
SDG&E	MSSION_2_QF	22496	MISSION	69	0.65	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MURRAY_6_UNIT	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	35.12	G1	SD-IV		Aug NQC	Wind
SDG&E	OCTILO_5_WIND	23318	OCO GEN G2	0.69	35.12	G2	SD-IV		Aug NQC	Wind
SDG&E	OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	SD-IV	San Diego, Pala Inner, Pala Outer		Market
SDG&E	OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	1	SD-IV	San Diego, Pala Inner, Pala Outer		Market
SDG&E	OTAY_6_LNDFL5	22604	OTAY	69	0.00		SD-IV	San Diego, Border	Not modeled Energy Only	Market
SDG&E	OTAY_6_LNDFL6	22604	OTAY	69	0.00		SD-IV	San Diego, Border	Not modeled Energy Only	Market
SDG&E	OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	SD-IV	San Diego, Border		Market
SDG&E	OTAY_6_UNITB1	22604	OTAY	69	2.03	1	SD-IV	San Diego, Border	Aug NQC	Market
SDG&E	OTMESA_2_PL1X3	22605	OTAYMGT1	18	165.16	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22606	OTAYMGT2	18	166.17	1	SD-IV	San Diego		Market

SDG&E	OTMESA_2_PL1X3	22607	OTAYMST1	16	272.27	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22262	PEN_CT1	18	170.18	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22263	PEN_CT2	18	170.18	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22265	PEN_ST	18	225.24	1	SD-IV	San Diego		Market
SDG&E	PIOPIC_2_CTG1	23162	PIO PICO CT1	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG2	23163	PIO PICO CT2	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG3	23164	PIO PICO CT3	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.23	2	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	SAMPSN_6_KELCO1	22704	SAMPSON	12.5	3.06	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	TERMEX_2_PL1X3	22982	TDM CTG2	18	156.44	1	SD-IV			Market
SDG&E	TERMEX_2_PL1X3	22983	TDM CTG3	18	156.44	1	SD-IV			Market
SDG&E	TERMEX_2_PL1X3	22981	TDM STG	21	280.13	1	SD-IV			Market
SDG&E	VLCNTR_6_VCSLR	22870	VALCNTR	69	0.96	DG	SD-IV	San Diego, Esco	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR1	22870	VALCNTR	69	1.03	DG	SD-IV	San Diego, Esco	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR2	22870	VALCNTR	69	2.05	DG	SD-IV	San Diego, Esco	Aug NQC	Solar
SDG&E	VSTAES_6_VESBT1	23541	Q1061_BESS	0.48	5.50	1	SD-IV	San Diego, Pala Outer	No NQC - est. data	Battery
SDG&E	VSTAES_6_VESBT1	23216	Q1294_BESS	0.48	5.50	C9	SD-IV	San Diego, Pala Outer	No NQC - est. data	Battery
SDG&E	WISTRA_2_WRSSR1	23287	Q429_G1	0.31	41.00	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	23597	Q1175_BESS	0.48	0.00	1	SD-IV		Energy Only	Battery
SDG&E	ZZZ_New Unit	23441	DW GEN2 G2	0.42	61.60	1	SD-IV		Aug NQC	Solar
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	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	22949	BUE GEN 1_G4	0.69	26.00	G3	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22020	AVOCADO	69	2.00	S2	SD-IV	San Diego, Pala Inner, Pala Outer	No NQC - Pmax	Battery
SDG&E	ZZZZ_New Unit	23234	Q1429	0.48	0.00	1	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZZ_New Unit	23443	DW GEN2 G3B	0.6	35.10	1	SD-IV		Aug NQC	Solar
SDG&E	ZZZZ_New Unit	23442	DW GEN2 G3A	0.6	49.20	1	SD-IV		Aug NQC	Solar
SDG&E	ZZZZ_New Unit	23544	Q1169_BESS 1	0.4	35.00	C8	SD-IV	San Diego, Pala Inner, Pala Outer	No NQC - Pmax	Battery
SDG&E	ZZZZ_New Unit	23519	Q1169_BESS 2	0.4	35.00	C8	SD-IV	San Diego, Pala Inner, Pala Outer	No NQC - Pmax	Battery
SDG&E	ZZZZ_New Unit	23131	Q183_G1	0.69	0.00	G1	SD-IV		Energy Only	Wind
SDG&E	ZZZZ_New Unit	23134	Q183_G2	0.69	0.00	G2	SD-IV		Energy Only	Wind
SDG&E	ZZZZ_New Unit	23100	ECOGEN1	0.48	41.1	G2	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZZZ_CBRLLO_6_PLSTP 1	22092	CABRILLO	69	0.00	1	SD-IV	San Diego	Aug NQC	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, Encina	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	SD-IV	San Diego, Encina	Retired by 2019	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market

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SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	SD-IV	San Diego	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_7_UNITC1	22604	OTAY	69	0.00	3	SD-IV	San Diego, Border	Aug NQC	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

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 – 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 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