California ISO

California Independent
System Operator

2021
LOCAL CAPACITY TECHNICAL ANALYSIS

UPDATED FINAL REPORT AND STUDY RESULTS

March 14, 2017

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

This report documents the results and recommendations of the 2021 Long-Term Local Capacity Technical (LCT) Study. The LCT Study objectives, inputs, methodologies and assumptions are the same as those discussed in the 2017 LCT Study to be adopted by the CAISO and CPUC in their 2017 Local Resource Adequacy needs.

Overall, the LCR trend compared with 2020, is down by about 700 MW mainly due to lower load forecast and new transmission projects. It is worth mentioning the following areas: (1) Humboldt, North Coast/North Bay, Sierra, Stockton, Kern and Big Creek/Ventura where LCR has decreased mostly due to load forecast; (2) Bay Area where LCR has significantly increased mostly due to new South Bay-Moss Landing sub-area needs; (3) Fresno and LA Basin where LCR has decreased due to load decrease and new transmission projects; (4) San Diego, where the LCR has increased mostly due to transmission constraints not accounted for in last years studies in part driven by cancelation of previously commited transmission upgrades in the Imperial Valley area.

The total capacity available has decreased by over 5,000 MW compared to 2020 as a combination of resource retirements and new resource developments.

The load forecast used in this study is based on the final adopted California Energy Demand Updated Forecast, 2016-2026 developed by the CEC; namely the mid-demand baseline with low-mid additional achievable energy efficiency (AAEE), posted: http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balencing_authority.php.

For comparison below you will find the 2017 and 2021 total LCR needs.

2017 Local Capacity Needs

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

2021 Local Capacity Needs

	Qualifying Capacity			2021 LCR Need Based on Category B			2021 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	20	198	218	121	0	**121**	169	0	**169**
North Coast/ North Bay	128	722	850	205	0	**205**	480	0	**480**
Sierra	1176	890	2066	1094	0	**1094**	1475	211*	**1686**
Stockton	197	532	729	146	0	**146**	364	40*	**404**
Greater Bay	933	5970	6903	2448	0	**2448**	5194	0	**5194**
Greater Fresno	231	3295	3526	731	0	**731**	1160	0	**1160**
Kern	15	106	121	91	0	**91**	105	0	**105**
LA Basin	1615	6180	7795	6697	0	**6697**	6898	0	**6898**
Big Creek/Ventura	517	3160	3677	2325	0	**2325**	2398	0	**2398**
San Diego/ Imperial Valley	263	4577	4840	4357	0	**4357**	4357	0	**4357**
Total	5095	25630	30725	18215	0	**18215**	22793	251	**23044**

* No local area is “overall deficient”. Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

The 2021 Fresno LCR base cases have been built with Path 15 at 1275 MW N-S due to historically seen overloads on Warnerville-Wilson 230 kV line. The overloads on the Panoche to Wilson 115 kV corridor are the worst at Path 15 high S-N flows; therefore the LCR requirement herein is understated. For future years, after the installation of the Wilson reactor, the ISO will develop LCR base cases with a stressed Path 15 in the S-N direction in order to correctly quantify local requirement needs.

The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between the 2020 Long-Term LCR study and this 2021 Long-Term LCR study.

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

A. Objectives

As was the objective of all previous LCT Studies, the intent of the 2021 Long-Term LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

Inputs and Methodology

The CAISO used the same Inputs and Methodology as does agreed upon by interested parties previously incorporated into the 2017 LCR Study. The following table sets forth a summary of the approved inputs and methodology that have been used in the previous 2017 LCR Study as well as this 2021 LCR Study:

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

Issue:	HOW INCORPORATED INTO THIS LCR STUDY:
Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year
• Load Forecast	Uses a 1-in-10 year summer peak load forecast
Methodology:	
• **Maximize Import Capability**	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• **QF/Nuclear/State/Federal Units**	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCR Study.
• **Maintaining Path Flows**	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
• **Performance Level B & C, including incorporation of PTO operational solutions**	This LCR 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 LCR Study.
Load Pocket:	
• **Fixed Boundary, including limited reference to published effectiveness factors**	This LCR 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 2017 as well as 2021 LCR Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning 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 NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[1] 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 NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The NERC Planning Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g.,

[1] Pub. Utilities Code § 345

security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

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

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

The N-1-1 vs N-2 terminology was introduced only as a temporal differentiation between two existing NERC Category 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.

E. 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:

a. 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.

b. 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 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.[2] All Category C requirements in this report refer to situations when in real time

[2] 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

(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.”

c. CAISO Statutory Obligation Regarding Safe Operation

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability 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)**.

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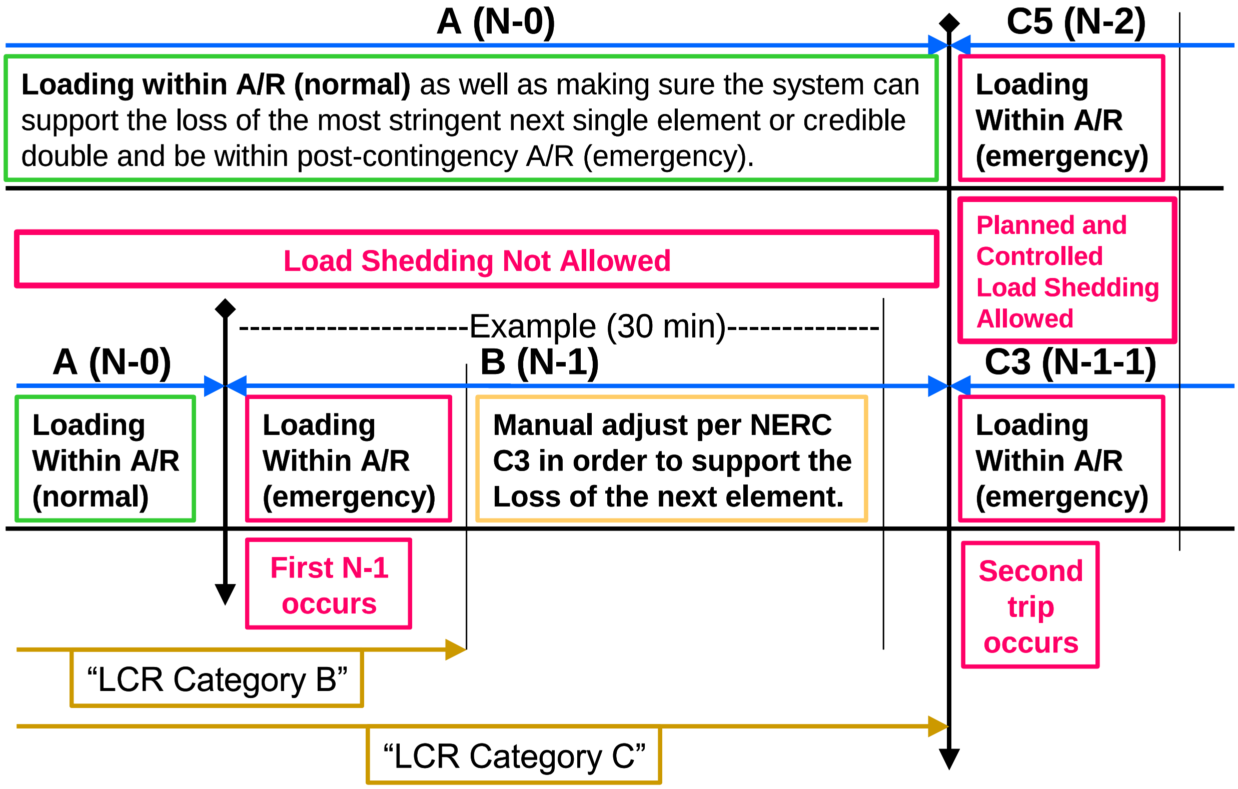
to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load 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 normal rating is to be used.

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another

length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.
Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.
CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.
Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.
Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.
Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

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.

F. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution "options" with varying ranges of potential service reliability consistent with CAISO's 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. 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.[3]

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

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

Table 4: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Criteria	Old RMR Criteria	Local Capacity Criteria
<u>A – No Contingencies</u>	X	X	X
<u>B – Loss of a single element</u>			
1. Generator (G-1)	X	X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
<u>C – Loss of two or more elements</u>			
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
<u>D – Extreme event – loss of two or more elements</u>			
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 in Table 4. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

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

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

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

[3] Applicable Rating – Based on 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. Post Transient Load Flow Assessment:

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

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

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

3. Stability Assessment:

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

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

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

The method used to develop the 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.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division[4] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

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

[4] 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.

using the load temperature relation determined from the latest peak load and temperature data of the division.

ii. 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.

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCR analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 19.0. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

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 was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Locational Capacity Requirement Study Results

A. Summary of Study Results

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

Table 5: 2017 Local Capacity Needs vs. Peak Load and Local Area Resources

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

Table 6: 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 Dependable Local Area Resources (MW)	2021 LCR as % of Total Area Resources
Humboldt	169	195	87%	218	78%
North Coast/North Bay	480	1318	36%	850	56%
Sierra	1686	1822	93%	2066	82%**
Stockton	404	1186	34%	729	55%**
Greater Bay	5194	9644	54%	6903	75%
Greater Fresno	1160	3240	36%	3526	33%
Kern	105	216	49%	121	87%
LA Basin	6898	19506	35%	7795	88%
Big Creek/Ventura	2398	3849	62%	3677	65%
San Diego/Imperial Valley	4357	4980	87%	4840	90%
Total	**23044**	**45956***	**50%***	**30725**	**75%**

* 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.

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

The term “Qualifying Capacity” used in this report is the “Net Qualifying Capacity” (“NQC”) posted on the CAISO web site at:

http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become operational before June 1 of 2021 have been included in this 2021 Long-Term LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

Regarding the main tables up front (page 2), the first column, “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.

B. Summary of Results by Local Area

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

1. Humboldt Area

Area Definition

The transmission tie lines into the area include:

1) Bridgeville-Cottonwood 115 kV line #1
2) Humboldt-Trinity 115 kV line #1

3) Willits-Garberville 60 kV line #1
4) Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

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

Total 2021 busload within the defined area: 198 MW with -13 MW of AAEE and 10 MW of losses resulting in total load + losses of 195 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.52	1	None	Aug NQC	Net Seller
FTSWRD_6_TRFORK				0.16		None	Not modeled Aug NQC	Market
FTSWRD_7_QFUNTS				0.00		None	Not modeled Aug NQC	QF/Selfgen
GRSCRK_6_BGCKWW				0.00		None	Energy Only	QF/Selfgen
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	2	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	4	None		Market
HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.27	5	None		Market
HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.27	6	None		Market
HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.27	7	None		Market
HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.27	8	None		Market
HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.27	9	None		Market
HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.27	10	None		Market
HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	None	Aug NQC	Net Seller
LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	None		Market
LOWGAP_1_SUPHR				0.52		None	Not modeled Aug NQC	Market
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.62	1	None	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.62	2	None	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.59	3	None	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.00		None	Not modeled Aug NQC	QF/Selfgen
BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	None	Retired	Market

Major new projects modeled:

1. Maple Creek Reactive Support
2. Garberville Reactive Support
3. Bridgeville 115/60 kV #1 transformer replacement

Critical Contingency Analysis Summary

Humboldt Overall:

The most critical contingency for the Humboldt area is the outage of the Cottonwood-Bridgeville 115 kV line overlapping with an outage of the gen-tie from Humboldt Bay Power Plant to units 1-4. The local area limitation is potential overload on the Humboldt -Trinity 115 kV Line. This contingency establishes a local capacity need of 169 MW in 2021 (includes 20 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Humboldt area is the outage of the Cottonwood-Bridgeville 115 kV line with one of the Humboldt Bay Power Plant units already out of service, which could potentially overload the Humboldt -Trinity 115 kV line. This contingency establishes a local capacity need of 121 MW in 2021 (includes 20 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units at least 5% effective to the above-mentioned constraint:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31156	BLUELKPP	1	65
31180	HUMB_G1	4	64
31180	HUMB_G1	3	64
31180	HUMB_G1	2	64
31180	HUMB_G1	1	64
31150	FAIRHAVN	1	61
31158	LP SAMOA	1	61
31182	HUMB_G3	10	61
31182	HUMB_G3	9	61
31182	HUMB_G3	8	61
31181	HUMB_G2	7	61
31181	HUMB_G2	6	61
31181	HUMB_G2	5	61
31152	PAC.LUMB	1	57
31152	PAC.LUMB	2	57
31153	PAC.LUMB	3	57

Changes compared to last year's results:

The load and losses have decreased by 5 MW from 2020 to 2021 and the total LCR has reduced by 1 MW.

Humboldt Overall Requirements:

	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	20	198	218

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[5]	121	0	121
Category C (Multiple)[6]	169	0	169

2. North Coast / North Bay Area

<u>Area Definition</u>

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

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

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

1) Cortina is out, Mendocino and Indian Valley are in
2) Cortina is out, Eagle Rock, Highlands and Homestake are in

[5] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[6] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

3) Willits and Lytonville are in, Kekawaka and Garberville are out
4) Vaca Dixon is out, Lakeville is in
5) Tulucay is in, Vaca Dixon is out
6) Lakeville is in, Sobrante is out
7) Ignacio is in, Sobrante and Crocket are out

Total 2021 busload within the defined area: 1348 MW with -61 MW of AAEE and 31 MW of losses resulting in total load + losses of 1318 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
CLOVDL_1_SOLAR				1.03		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	Market
CSTOGA_6_LNDFIL				0.00		Fulton, Lakeville	Not modeled Energy Only	Market
FULTON_1_QF				0.03		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	68.00	1	Eagle Rock, Fulton, Lakeville		Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville		Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	53.00	1	Fulton, Lakeville		Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	2	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville		Market
GYSRVL_7_WSPRNG				1.48		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HILAND_7_YOLOWD				0.00		Eagle Rock, Fulton, Lakeville	Energy Only	Market
HIWAY_7_ACANYN				0.18		Lakeville	Not modeled Aug NQC	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled Aug NQC	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	1.11	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Net Seller
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.96	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.95	2	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.94	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.77	1	Fulton, Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	Fulton, Lakeville	Aug NQC	MUNI

POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_7_VECINO				0.01		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville		Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	3.56	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN	38020	CITY UKH	115	0.49	1	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
UKIAH_7_LAKEMN	38020	CITY UKH	115	1.21	2	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	1	Fulton, Lakeville	Retired	Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	2	Fulton, Lakeville	Retired	Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	0.00	1	Fulton, Lakeville	Retired	Market

Major new projects modeled:

1. Napa – Tulucay 60 kV line upgrade
2. Vaca Dixon-Lakeville 230 kV reconductoring

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical overlapping contingency is an outage of the Geysers #3 - Geyser #5 115 kV line and the Cortina-Mendocino 115 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a local capacity need of 213 MW in 2021 (includes 0 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Cortina-Mendocino 115 kV transmission line with Geysers 11 unit out of service. The sub-area limitation is thermal overloading of the parallel Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a local capacity need of 205 MW in 2021 (includes 0 MW of QF/Muni generation).

Effectiveness factors:

The following units have at least 5% effectiveness to the above-mentioned constraint:

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

Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Lakeville # 2 60 kV line (Lakeville-Petaluma A – Cotati). This limiting contingency establishes a local capacity need of 310 MW in 2021 (includes 14 MW of QF and 55 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the units required to meet the Eagle Rock pocket count towards the Fulton total requirement.

Effectiveness factors:

The following table has units within the Fulton pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31466	SONMA LF	**1**	52
31422	GEYSER17	1	12
31404	WEST FOR	1	12
31404	WEST FOR	2	12
31414	GEYSER12	1	12
31418	GEYSER14	1	12
31420	GEYSER16	1	12
31402	BEAR CAN	1	12
31402	BEAR CAN	2	12

38110	NCPA2GY1	1	12
38112	NCPA2GY2	1	12
32700	MONTICLO	1	10
32700	MONTICLO	2	10
32700	MONTICLO	3	10
31435	GEO.ENGY	1	6
31435	GEO.ENGY	2	6
31408	GEYSER78	1	6
31408	GEYSER78	2	6
31412	GEYSER11	1	6
31406	GEYSR5-6	1	6
31406	GEYSR5-6	2	6

Lakeville Sub-area (North Coast/North Bay Overall)

The most limiting contingency for the North Coast/North Bay Area is a common mode outage of the Vaca Dixon-Lakeville and Vaca Dixon-Tulucay 230 kV lines. The area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line, the Bridgeville-Garberville 60 kV line and the Sobrante-Moraga 115 kV line. This limiting contingency establishes a local capacity need of 480 MW in 2021 (includes 14 MW of QF and 114 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

Local capacity requirement in the North Coast/North Bay area substantially depend on the generation in the Bay Area, especially Pittsburg sub-area.

The study assumed that the Vaca Dixon- Lakeville 230 kV line is reconductored. If it is not reconductored, than the limiting contingency will be single outage of the Vaca Dixon-Tulucay 230 kV line. This contingency may overload the Vaca Dixon- Lakeville 230 kV line. In this case, local capacity requirement will be 504 MW. If this line is not re-conductored, but re-rated, local capacity requirement will be 480 MW as described above.

Changes compared to last year's results:

Overall the load and losses forecast went down by 158 MW compared to 2020. The overall LCR requirement went down by 29 MW as a combination of load decrease and need to use North Coast/North Bay resources to mitigate potential overload of Sobrante-Moraga 115 kV due to resource retirements in the Pittsburg sub-area.

North Coast/North Bay Overall Requirements:

2021	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	14	114	722	850

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category P1 (Single)[7]	205	0	205
Category P7 (Multiple)[8]	480	0	480

3. Sierra Area

<u>Area Definition</u>

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

[7] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[8] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

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

Total 2021 busload within the defined area: 1806 MW with -64 MW of AAEE and 80 MW of losses resulting in total load + losses of 1822 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALLGNY_6_HYDRO1				0.26		South of Table Mountain	Not modeled Aug NQC	Market
APLHIL_1_SLABCK				0.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
BANGOR_6_HYDRO				0.54		South of Table Mountain	Not modeled Aug NQC	Market
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BIOMAS_1_UNIT 1	32156	WOODLAND	9.11	23.92	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.72		Weimer, Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
BOWMN_6_HYDRO	32480	BOWMAN	9.11	2.19	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				0.84		South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.11	2.90	1	South of Table Mountain	Aug NQC	MUNI
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table	Aug NQC	MUNI

						Mountain		
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Aug NQC	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
DAVIS_1_SOLAR1				0.82		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DAVIS_1_SOLAR2				0.88		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DAVIS_7_MNMETH				2.06		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.11	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.11	3.74	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
FMEADO_6_HELLHL	32486	HELLHOLE	9.11	0.26	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
GOLDHL_1_QF				0.00		Placerville, South of Rio Oso, South of Palermo,	Not modeled	QF/Selfgen

						South of Table Mountain		
GRIDLY_6_SOLAR	38054	GRIDLEY	60	0.00	1	Pease, South of Palermo, South of Table Mountain	Energy Only	Market
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	7.69	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
GRNLF1_1_UNITS	32491	GRNLEAF1	13.8	39.27	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	35.01	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.11	6.44	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HIGGNS_1_COMBIE				0.00		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
HIGGNS_7_QFUNTS				0.24		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.11	10.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
LIVEOK_6_SOLAR				0.87		Pease, South of Table Mountain	Not modeled Aug NQC	Market
LODIEC_2_PL1X2	38123	LODI CT1	18	166.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
LODIEC_2_PL1X2	38124	LODI ST1	18	114.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	9.59	1	South of Table Mountain	Aug NQC	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	28.51	1	South of Table Mountain	Aug NQC	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
OROVIL_6_UNIT	31888	OROVLLE	9.11	7.50	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
OXBOW_6_DRUM	32484	OXBOW F	9.11	6.00	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.11	2.58	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.11	2.59	2	Drum-Rio Oso, South of	Aug NQC	QF/Selfgen

						Table Mountain		
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	3.88	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PLSNTG_7_LNCLND	32408	PLSNT GR	60	2.79		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	57.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.90	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				1.14		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.11	11.09	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.11	10.36	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.11	5.74	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.73	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.11	20.89	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	60.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	3.00		South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	10.68	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
WISE_1_UNIT 2	32512	WISE	12	0.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.11	23.98	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	Net Seller
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market

NA	32162	RIV.DLTA	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
UCDAVS_1_UNIT	32166	UC DAVIS	9.11	3.50	RN	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen

Major new projects modeled:

1. Gold Hill-Missouri Flat #1 and #2 115 kV line reconductoring
2. Rio Oso #1 and #2 230/115 kV transformer replacement
3. Pease 115/60 kV transformer addition

<u>Critical Contingency Analysis Summary</u>

Placerville Sub-area

No requirements due to the Missouri Flat-Gold Hill 115 kV lines reconductoring project.

Placer Sub-area

The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 62 MW (includes 38 MW of QF/MUNI) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Chicago Park, Dutch Flat #1, Wise units 1&2, Newcastle, and Halsey) have the same effectiveness factor.

Pease Sub-area

The most critical contingency is the loss of the Palermo-Pease 115 kV line followed by Pease-Rio Oso 115 kV line. The area limitation is thermal overloading of the Table Mountain-Pease 60 kV line. This limiting contingency establishes a LCR of 68 MW (includes 35 MW of QF generation) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo-Pease 115 kV line with YCEC unit out of service. The area limitation is thermal overloading of the Table Mountain-Pease 60 kV line. This limiting contingency establishes a local capacity need of 55 MW (includes 35 MW of QF generation) in 2021.

Effectiveness factors:

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

Drum-Rio Oso Sub-area

No requirement due to the Rio Oso 230/115 kV Transformer Upgrade project as well as lower load forecast.

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 kV line followed by loss of the Rio Oso-Atlantic #1 230 kV line. The sub-area limitation is thermal overloading of the Rio Oso-Lincoln 115 kV line. This limiting contingency establishes a LCR of 761 MW (includes 21 MW of QF and 593 MW of MUNI generation as well as 69 MW of deficiency) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 kV line with Middle Fork unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 350 MW (includes 21 MW of QF and 593 MW of MUNI generation) in 2021.

Effectiveness factors:

The following table has all units in South of Rio Oso sub-area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32456	MIDLFORK	1	30
32456	MIDLFORK	2	30
32458	RALSTON	1	30
32486	HELLHOLE	1	30

32508	FRNCH MD	1	30
32510	CHILIBAR	1	30
32513	ELDRADO1	1	30
32514	ELDRADO2	1	30
32460	NEWCSTLE	1	29
32478	HALSEY F	1	28
32512	WISE	1	28
32500	ULTR RCK	1	26
38114	STIG CC	1	13
38123	LODI CT1	1	13
38124	LODI ST1	1	13
32462	CHI.PARK	1	13
32498	SPILINCF	1	10
32464	DTCHFLT1	1	9

South of Palermo Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Rio Oso-Pease 115 kV line. This limiting contingency establishes a LCR of 1686 MW (includes 26 MW of QF and 638 MW of MUNI generation as well as 211 MW of deliciency) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Colgate-Rio Oso 230 kV line with Belden unit out of service. The area limitation is thermal overloading of the Rio Oso-Pease 115 kV line. This contingency establishes in 2021 a LCR of 1094 MW (includes 26 MW of QF and 638 MW of MUNI generation).

Effectiveness factors:

The following table has all units in South of Palermo sub-area and their effectiveness factor to the above-mentioned constraint

Gen Bus #	Gen Name	Gen ID	Eff Fctr (%)
31784	BELDEN	1	15
31786	ROCK CK1	1	15
31788	ROCK CK2	1	15
31790	POE 1	1	15
31792	POE 2	1	15
31812	CRESTA	1	15
31812	CRESTA	2	15
31820	BCKS CRK	1	15
31820	BCKS CRK	2	15
32498	SPILINCF	1	12
32500	ULTR RCK	1	12

32502	DTCHFLT2	1	12
32156	WOODLAND	1	12
32454	DRUM 5	1	12
32472	SPAULDG	1	12
32472	SPAULDG	2	12
32472	SPAULDG	3	12
32474	DEER CRK	1	12
32476	ROLLINSF	1	12
32480	BOWMAN	1	12
32484	OXBOW F	1	12
32488	HAYPRES+	1	12
32488	HAYPRES+	2	12
32504	DRUM 1-2	1	12
32504	DRUM 1-2	2	12
32506	DRUM 3-4	1	12
32506	DRUM 3-4	2	12
32464	DTCHFLT1	1	12
32462	CHI.PARK	1	12
32166	UC DAVIS	1	12
32478	HALSEY F	1	11
32512	WISE	1	11
32460	NEWCSTLE	1	11
32162	RIV.DLTA	1	11
32510	CHILIBAR	1	11
32513	ELDRADO1	1	11
32514	ELDRADO2	1	11
32456	MIDLFORK	1	10
32456	MIDLFORK	2	10
32458	RALSTON	1	10
32486	HELLHOLE	1	10
32508	FRNCH MD	1	10
38114	STIG CC	1	5
38123	LODI CT1	1	5
38124	LODI ST1	1	5

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso and Table Mountain-Palermo 230 kV double circuit tower line. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limitation establishes a local capacity need of 856 MW in 2021 (includes 66 MW of QF and 1110 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Table Mountain-Palermo 230 kV line with Belden unit out of service. The area limitation is thermal overloading of the Table Mountain-Rio Oso 230 kV line. This limiting contingency establishes a local capacity need of 820 MW (includes 66 MW of QF and 1110 MW of MUNI generation) in 2021.

Effectiveness factors:

The following table has effectiveness factor to the most critical contingency.

Gen Bus #	Gen Name	Gen ID	Eff Fctr (%)
31814	FORBSTWN	1	7
31794	WOODLEAF	1	7
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31890	PO POWER	1	6
31890	PO POWER	2	6
31888	OROVLLE	1	6
31834	KELLYRDG	1	6
32450	COLGATE1	1	4
32466	NARROWS1	1	4
32468	NARROWS2	1	4
32452	COLGATE2	1	4
32470	CMP.FARW	1	4
32451	FREC	1	4
32490	GRNLEAF1	1	4
32490	GRNLEAF1	2	4
32496	YCEC	1	4
32494	YUBA CTY	1	4
32492	GRNLEAF2	1	4
32498	SPILINCF	1	2
31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2
31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31786	ROCK CK1	1	2
31790	POE 1	1	2
31792	POE 2	1	2
31784	BELDEN	1	2
32500	ULTR RCK	1	2
32156	WOODLAND	1	2
32510	CHILIBAR	1	2
32513	ELDRADO1	1	2
32514	ELDRADO2	1	2
32478	HALSEY F	1	2
32460	NEWCSTLE	1	1
32458	RALSTON	1	1
32512	WISE	1	1
32456	MIDLFORK	1	1
32456	MIDLFORK	2	1
32486	HELLHOLE	1	1
32508	FRNCH MD	1	1
32162	RIV.DLTA	1	1
32502	DTCHFLT2	1	1
32462	CHI.PARK	1	1
32464	DTCHFLT1	1	1

32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32166	UC DAVIS	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1
32472	SPAULDG	3	1
32480	BOWMAN	1	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
38124	LODI ST1	1	1
38123	LODI CT1	1	1
38114	STIG CC	1	1

Changes compared to last year's results:

The load forecast went down by 172 MW as compared to 2020. Overall the total LCR for 2021 for the Sierra area has decreased by 17 MW due to a combination of load decrease and delay in implementation of transmission projects.

Sierra Overall Requirements:

2021	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	66	1110	890	2066

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[9]	1094	0	1094
Category C (Multiple)[10]	1475	211	1686

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

[10] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

4. Stockton Area

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

<u>Area Definition</u>

Tesla-Bellota Sub-Area Definition

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

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

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

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

Lockeford Sub-Area Definition

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

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

The substations that delineate the Lockeford Sub-area are:

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

Weber Sub-Area Definition

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

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

The substations that delineate the Weber Sub-area are:

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

Total 2021 busload within the defined area: 1247 MW with -78 MW of AAEE and 17 MW of losses resulting in total load + losses of 1186 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.41	1	Tesla-Bellota	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.41	2	Tesla-Bellota	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.42	3	Tesla-Bellota	Aug NQC	MUNI
COGNAT_1_UNIT	33818	COG.NTNL	12	38.42	1	Weber	Aug NQC	Net Seller
CURIS_1_QF				0.33		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
FROGTN_7_UTICA				0.00		Tesla-Bellota, Stanislaus	Energy Only	Market
LOCKFD_1_BEARCK				0.00		Tesla-Bellota	Not modeled Energy Only	Market
LOCKFD_1_KSOLAR				0.00		Tesla-Bellota	Not modeled Energy Only	Market
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford		MUNI
PEORIA_1_SOLAR				0.97		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PHOENX_1_UNIT				1.35		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
RIVRBK_1_LNDFIL				0.00		Tesla-Bellota, Stanislaus	Not modeled Energy Only	Market
SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	132.96	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	6.29	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	1.57	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.00	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	12.19	1	Tesla-Bellota	Aug NQC	Net Seller
TULLCK_7_UNITS	34076	TULLOCH	6.9	6.16	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	6.16	2	Tesla-Bellota	Aug NQC	MUNI

TULLCK_7_UNITS	34076	TULLOCH	6.9	4.54	3	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	15.89	1	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.09		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	MUNI
WEBER_6_FORWRD				4.20		Weber	Not modeled Aug NQC	Market
NA	33687	STKTN WW	60	1.50	1	Weber	No NQC - hist. data	QF/Selfgen
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - hist. data	QF/Selfgen
New Unit	34051	Q539	34.5	20.00	1	Tesla-Bellota	No NQC - Pmax	Market
SANJOA_1_UNIT 1	33808	SJ COGEN	13.8	48	1	Tesla-Bellota		QF/Selfgen
SMPRIP_1_SMPSON	33810	SP CMPNY	13.8	45.6	1	Tesla-Bellota	Aug NQC	Market
THMENG_1_UNIT 1	33806	TH.E.DV.	13.8	17.32	1	Tesla-Bellota	Aug NQC	Net Seller
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	0.00		Tesla-Bellota	Retired	QF/Selfgen

Major new projects modeled:

1. Weber-Stockton “A” #1 and #2 60 kV Reconductoring
2. Vierra 115 kV Loop-in
3. Ripon 115 kV line

Critical Contingency Analysis Summary

Stanislaus Sub-area

The critical contingency for the Stanislaus sub-area is the loss of Bellota-Riverbank-Melones 115 kV circuit with Stanislaus PH out of service. The area limitation is thermal overloading of the River Bank Jct.-Manteca 115 kV line. This limiting contingency establishes a local capacity need of 146 MW (including 16 MW of QF and 88 MW of MUNI generation) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Tesla-Bellota Sub-area

The most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Vierra 115 kV and the Tesla-Schulte #2 115 kV lines. The area limitation is thermal overload of the Tesla-Schulte #1 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 312 MW (includes 64 MW of QF and 106 MW of

MUNI generation) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Stanislaus sub-area count towards the Tesla-Bellota sub-area LCR need.

The Stanislaus sub-areas requirement is enogh to mitigate the most critical single contingency for the Tesla-Bellota pocket as well.

Effectiveness factors:

The effectiveness factors for the most critical contingency are listed below:

Gen Bus#	Gen Name	Gen ID	Eff Fctr (%)
33805	GWFTRCY1	1	71
33807	GWFTRCY2	1	71
33811	Q268ST1	1	71
33808	SJ COGEN	1	35
33810	SP CMPNY	1	31
34062	STANISLS	1	28
34050	CH.STN.	1	23
33917	FBERBORD	1	22
34078	SPRNG GP	1	20
34060	SANDBAR	1	20
34074	BEARDSLY	1	20
34058	DONNELLS	1	20
34076	TULLOCH	1	18
34076	TULLOCH	2	18
33806	TH.E.DV.	1	9
34056	STNSLSRP	1	8
33814	CPC STCN	1	3
33850	CAMANCHE	1	3
33850	CAMANCHE	2	3
33850	CAMANCHE	3	3

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a local capacity need of 65 MW (including 2 MW of QF and 23 MW of MUNI as well as 40 MW of deficiency) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Weber Sub-area

The critical contingency for the Weber area is the loss of Stockton A-Weber #1 & #2 60 kV lines. The area limitation is thermal overloading of the Stockton A-Weber #3 60 kV line. This limiting contingency establishes a local capacity need of 27 MW (including 2 MW of QF generation) in 2021 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Stockton Overall

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

Changes compared to last year's results:

The 2021 load forecast went up by 44 MW and the overall LCR has remained the same as compared to the 2020.

Stockton Overall Requirements:

2021	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	68	129	532	729

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[11]	146	0	146
Category C (Multiple)[12]	364	40	404

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

5. Greater Bay Area

Area Definition

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Contra Costa P.P. 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Metcalf 500 kV
16) Moss Landing-Metcalf #1 230 kV
17) Moss Landing-Metcalf #2 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville is out Sobrante is in
2) Ignacio is out Sobrante is in
3) Parkway is out Moraga is in
4) Bahia is out Moraga is in
5) Lambie SW Sta is in Vaca Dixon is out
6) Peabody is out Contra Costa P.P. is in
7) Tesla is out Kelso is in
8) Tesla is out Delta Switching Yard is in
9) Tesla is out Pittsburg is in
10) Tesla is out Pittsburg is in
11) Tesla is out Newark is in

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[12] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

12) Tesla is out Newark is in
13) Tesla is out Ravenswood is in
14) Tesla is out Metcalf is in
15) Moss Landing is out Metcalf is in
16) Moss Landing is out Metcalf is in
17) Moss Landing is out Metcalf is in
18) Oakdale TID is out Newark is in
19) Oakdale TID is out Newark is in

Total 2021 busload within the defined area: 9630 MW with -450 MW of AAEE, 196 MW of losses and 268 MW of pumps resulting in total load + losses + pumps of 9644 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	13.47	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	13.47	11	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	13.47	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	13.47	9	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	13.47	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	13.47	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	13.47	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	13.47	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	3.37	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	3.37	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	12.51	3	Contra Costa	Pumps	MUNI
BLHVN_7_MENLOP				0.56			Not modeled	Net Seller
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	36.37	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	20.14	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	8.03	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	45.80	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	35.83	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	22.98	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	29.14	1	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.00	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
CAYTNO_2_VASCO	30531	0162-WD	230	4.30	FW	Contra Costa	Aug NQC	Market
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_2_CTG1	33188	MARSHCT1	16.4	191.35	1	Contra Costa	Aug NQC	Market
COCOPP_2_CTG2	33188	MARSHCT2	16.4	189.30	2	Contra Costa	Aug NQC	Market
COCOPP_2_CTG3	33189	MARSHCT3	16.4	191.45	3	Contra Costa	Aug NQC	Market
COCOPP_2_CTG4	33189	MARSHCT4	16.4	191.44	4	Contra Costa	Aug NQC	Market
COCOSB_6_SOLAR				0.00		Contra Costa	Not modeled Energy Only	Market
CONTAN_1_UNIT	36856	CCA100	13.8	27.70	1	San Jose, South Bay-Moss Landing	Aug NQC	MUNI

CROKET_7_UNIT	32900	CRCKTCOG	18	184.26	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	1	San Jose, South Bay-Moss Landing		MUNI
CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	2	San Jose, South Bay-Moss Landing		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose, South Bay-Moss Landing		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose, South Bay-Moss Landing		MUNI
CUMBIA_1_SOLAR	33102	COLUMBIA	0.38	0.00	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Aug NQC	Market
DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose, South Bay-Moss Landing		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose, South Bay-Moss Landing		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose, South Bay-Moss Landing		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	190.12	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	186.19	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	186.19	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GRZZLY_1_BERKLY	32741	HILLSIDE_12	12.5	24.02	1	None	Aug NQC	QF/Selfgen
KELSO_2_UNITS	33813	MARIPCT1	13.8	47.08	1	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33815	MARIPCT2	13.8	47.07	2	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33817	MARIPCT3	13.8	47.07	3	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33819	MARIPCT4	13.8	47.07	4	Contra Costa	Aug NQC	Market
KIRKER_7_KELCYN				3.27		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.12		None	Not modeled Aug NQC	Market
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35858	LECEFST1	13.8	107.88	1	San Jose, South Bay-Moss Landing		Market

LFC 51_2_UNIT 1	35310	PPASSWND	21	2.02	1	None	Aug NQC	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	Contra Costa	Aug NQC	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Aug NQC	Market
MARTIN_1_SUNSET				1.88		None	Not modeled Aug NQC	QF/Selfgen
METCLF_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	South Bay-Moss Landing	Aug NQC	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	South Bay-Moss Landing	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	South Bay-Moss Landing	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.16		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.02		San Jose, South Bay-Moss Landing	Not modeled Aug NQC	QF/Selfgen
MOSSLD_2_PSP1	36221	DUKMOSS1	18	138.72	1	South Bay-Moss Landing	85% of existing	Market
MOSSLD_2_PSP1	36222	DUKMOSS2	18	138.72	1	South Bay-Moss Landing	85% of existing	Market
MOSSLD_2_PSP1	36223	DUKMOSS3	18	156.06	1	South Bay-Moss Landing	85% of existing	Market
MOSSLD_2_PSP2	36224	DUKMOSS4	18	138.72	1	South Bay-Moss Landing	85% of existing	Market
MOSSLD_2_PSP2	36225	DUKMOSS5	18	138.72	1	South Bay-Moss Landing	85% of existing	Market
MOSSLD_2_PSP2	36226	DUKMOSS6	18	156.06	1	South Bay-Moss Landing	85% of existing	Market
NEWARK_1_QF				0.02		None	Not modeled Aug NQC	QF/Selfgen
OAK C_1_EBMUD				0.73		Oakland	Not modeled Aug NQC	MUNI
OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Oakland		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.44	1	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	Ames		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	Market
RUSCTY_2_UNITS	35304	RUSELCT1	15	172.35	1	Ames	No NQC - Pmax	Market
RUSCTY_2_UNITS	35305	RUSELCT2	15	172.35	1	Ames	No NQC - Pmax	Market

RUSCTY_2_UNITS	35306	RUSELST1	15	241.00	1	Ames	No NQC - Pmax	Market
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	FOREBAYW	22	0.14	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.82	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.09	1	None	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.70	1	Pittsburg	Aug NQC	Market
STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.70	1	Pittsburg	Aug NQC	Market
STOILS_1_UNITS	32923	CHEVGEN3	13.8	0.32	3	Pittsburg	Aug NQC	Market
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.01	1	Pittsburg	Aug NQC	Net Seller
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.00	2	Pittsburg	Aug NQC	Net Seller
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.00	3	Pittsburg	Aug NQC	Net Seller
UNCHEM_1_UNIT	32920	UNION CH	9.11	10.45	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.38	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.38	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.38	3	Pittsburg	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	21.94	1	Contra Costa	Aug NQC	Wind
USWNDR_2_SMUD2	32186	SOLANO	34.5	42.60	1	Contra Costa	Aug NQC	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	4.18	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.78	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.78	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	39233	GRNRDG	0.69	15.66	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	3.42	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	1.45	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose, South Bay-Moss Landing	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose, South Bay-Moss Landing		QF/Selfgen
NA	36209	SLD ENRG	12.5	0.00	1	South Bay-Moss Landing		QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	Net Seller
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	Net Seller
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	Net Seller
ZANKER_1_UNIT 1	35861	SJ-SCL W	4.3	5.00	RN	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
New Unit	30524	0354-WD	230	1.83	EW	Contra Costa	No NQC - Pmax	Market
New Unit	35622	SWIFT	115	4.00	BT	South Bay-Moss Landing	No NQC - Pmax	Market
New Unit	35302	NUMMI-LV	12.6	0.00	RN		Energy Only	Market
New Unit	35307	A100US-L	12.6	0.00	RN		Energy Only	Market
New Unit	35859	HGST-LV	12.4	0.00	RN		Energy Only	Market
CARDCG_1_UNITS	33463	CARDINAL	12.5	0.00	R1	None	Retired	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	0.00	R2	None	Retired	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	RT	Contra Costa	Retired	Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	RT	Contra Costa	Retired	Market
GWFPW1_6_UNIT	33131	GWF #1	9.11	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	0.00	1	Pittsburg	Retired	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen

GWFPW4_6_UNIT 1	33134	GWF #4	13.8	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	0.00	1	Pittsburg	Retired	QF/Selfgen
MOSSLD_7_UNIT 6	36405	MOSSLND6	22	0.00	1	South Bay-Moss Landing	Retired by 2021	Market
MOSSLD_7_UNIT 7	36406	MOSSLND7	22	0.00	1	South Bay-Moss Landing	Retired by 2021	Market
PITTSP_7_UNIT 5	33105	PTSB 5	18	0.00	1	Pittsburg	Retired by 2019	Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	1	Pittsburg	Retired by 2019	Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	1	Pittsburg	Retired by 2019	Market
UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	None	Retired	QF/Selfgen

Major new projects modeled:

1. Vaca Dixon-Lakeville 230 kV line reconductoring
2. East Shore-Oakland J 115 kV reconductoring project
3. Evergreen-Mabury Conversion to 115 kV
4. Metcalf-Evergreen 115 kV line reconductoring
5. Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV upgrade
6. Embarcadero-Potrero 230 kV transmission project
7. Morgan Hill Area Reinforcement
8. Tesla-Newark 230 kV Path upgrade
9. A few small renewable resources
10. Pittsburg Power Plant retirement

Critical Contingency Analysis Summary

Oakland Sub-area

The critical contingency for the Oakland pocket is the loss of both C-X #2 and C-X #3 115 kV Cables. The area limitation is thermal overloading of the remaining Moraga-Claremont 115 kV lines above their emergency rating. This limiting contingency establishes a local capacity need of 72 MW in 2021 (includes 49 MW of MUNI generation) as minimum capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

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

Llagas Sub-area

The most critical contingency is an outage of Metcalf D-Morgan Hill 115 kV line with the Spring 230/115 kV transformer bank #1. The area limitation is the thermal overloading of the Metcalf - Green Valley – Llagas 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 6 MW in 2021 (includes 0 MW of QF and MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

San Jose Sub-area

The most critical contingency in the San Jose sub-area is the Metcalf - Evergreen #1 and #2 115 kV lines. The limiting element is the San Jose STA “A”-“B” 115 kV line and establishes a local capacity 404 MW in 2021 (includes 5 MW of QF and 230 MW of MUNI generation) as minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

South Bay-Moss Landing Sub-area

The most critical contingency is an outage of the Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV. The area limitation is thermal overloading of the Las Aguillas-Moss Landing 230 kV. This limiting contingency establishes a LCR of 2043 MW in 2021 (includes 5 MW of QF and 230 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

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

Ames and Pittsburg Sub-areas Combined

The need for OTC generation in this sub-area is eliminated after the following projects are operational: Tesla-Pittsburg 230 kV Reconductoring, Moraga 230/115 kV Banks Replacement, Contra Costa-Moraga 230 kV Reconductoring and the Vaca Dixon-Lakeville 230 kV Reconductoring.

The two most critical contingencies listed below together establish a local capacity need of 2577 MW in 2021 as follows: 480 MW in NCNB (includes 14 MW of QF and 114 MW of Muni generation) and 2097 MW in the Bay Area – 402 MW in Ames (includes 0 MW of QF and MUNI generation) and 1695 MW in Pittsburg (includes 200 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within these sub-areas.

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

The most critical contingency in North Coast/North Bay area is an outage of Vaca Dixon-Lakeville 230 kV line overlapped with the outage of Vaca Dixon-Tulucay 230 kV lines. The limiting element is the Moraga-Sobrante 115 kV line.

Effectiveness factors:

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

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with Gateway out of service. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 956 MW in 2021 (includes 264 MW of MUNI pumps and 289 MW of wind generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Bay Area that are at least 10% effective.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
33175	ALTAMONT	1	83
38760	DELTA E	10	71
38760	DELTA E	11	71
38765	DELTA D	8	71
38765	DELTA D	9	71
38770	DELTA C	6	71
38770	DELTA C	7	71
38815	DELTA B	4	71
38815	DELTA B	5	71
38820	DELTA A	3	71
33170	WINDMSTR	1	68
33118	GATEWAY1	1	23
33119	GATEWAY2	1	23
33120	GATEWAY3	1	23
33116	C.COS 6	1	23
33117	C.COS 7	1	23
33133	GWF #3	1	23
33134	GWF #4	1	23
33178	RVEC_GEN	1	23
33131	GWF #1	1	22

32179	T222	1	18
32188	P0611G	1	18
32190	Q039	1	18
32186	P0609	1	18
32171	HIGHWND3	1	18
32177	Q0024	1	18
32168	ENXCO	2	18
32169	SOLANOWP	1	18
32172	HIGHWNDS	1	18
32176	SHILOH	1	18
33838	USWP_#3	1	18
32173	LAMBGT1	1	14
32174	GOOSEHGT	2	14
32175	CREEDGT1	3	14
35312	SEAWESTF	1	11
35316	ZOND SYS	1	11
35320	USW FRIC	1	11

Bay Area overall

The most critical need is the aggregate of sub-area requirements. This establishes a LCR of 5387 MW in 2021 (including 232 MW of QF, 410 MW of MUNI and 291 MW of wind generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Tesla-Metcalf 500 kV with Delta Energy Center out of service. The area limitation is reactive margin. This limiting contingency establishes a local capacity need of 2448 MW in 2021 (includes 232 MW of QF, 291 MW of wind and 410 MW of MUNI generation).

Effectiveness factors:

For most helpful procurement information please read procedure M-2210Z effectiveness factors at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

Compared with 2020 the load forecast went down by 642 MW within the physically defined Bay Area, however the total load has actually decreased by only 487 MW due to the new definition that includes the Moss Landing areas as well. The LCR has increased by 1003 MW due to new LCR requirements due to the redefinition triggered by new South Bay-Moss Landing sub-area need.

Bay Area Overall Requirements:

2021	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	291	232	410	5970	6903

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[13]	2448	0	2448
Category C (Multiple)[14]	5194	0	5194

6. Greater Fresno Area

<u>Area Definition</u>

The transmission facilities coming into the Greater Fresno area are:

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

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

[14] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta is in
3) Gates 230 is out Gates 70 is in
4) Mercy Springs 230 is out Mercy Springs 70 is in
5) Los Banos 230 is out Los Banos 70 is in
6) Los Banos 230 is out Los Banos 70 is in
7) Warnerville is out Wilson is in
8) Melones is out North Merced is in
9) Panoche is out Tranquility #1 is in
10) Panoche is out Tranquility #2 is in
11) Panoche 230 is out Panoche 115 is in
12) Panoche 230 is out Panoche 115 is in
13) Corcoran is in Smyrna is out
14) Coalinga is in San Miguel is out

Total 2021 busload within the defined area: 3267 MW with -108 MW of AAEE and 81 MW of losses resulting in total load + losses of 3240 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADMEST_6_SOLAR	34315	ADAMS_E	12.5	0.00	1	Wilson, Herndon	Energy Only	Market
AGRICO_6_PL3N5	34608	AGRICO	13.8	20.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Wilson, Coalinga	Energy Only	Market
AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Wilson, Coalinga	Energy Only	Market
AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Wilson, Coalinga	Energy Only	Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	33.00	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BORDEN_2_QF	34253	BORDEN D	12.5	0.78	QF	Wilson	Aug NQC	Net Seller
CANTUA_1_SOLAR	34349	CANTUA_D	12.5	7.15	1	Wilson	Aug NQC	Market
CANTUA_1_SOLAR	34349	CANTUA_D	12.5	7.15	2	Wilson	Aug NQC	Market
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	4.29	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	1.30	1	Wilson, Coalinga	Aug NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.85	2	Wilson, Coalinga	Aug NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	8.60	1	Wilson, Herndon	Aug NQC	Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	34.58	1	Wilson, Coalinga	Aug NQC	Net Seller
CORCAN_1_SOLAR1				13.80		Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
CORCAN_1_SOLAR2				7.59		Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market

CRESSY_1_PARKER	34140	CRESSEY	115	1.21		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.71	1	Wilson, Borden	Aug NQC	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson, Borden	Aug NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson, Borden	Aug NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon, Reedley		Market
ELCAP_1_SOLAR				1.04		Wilson	Not Modeled Aug NQC	Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	8.71	1	Wilson	Aug NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	94.20	1	Wilson	Aug NQC	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.66	4	Wilson, Borden	Aug NQC	Net Seller
FRIANT_6_UNITS	34636	FRIANTDM	6.6	2.49	3	Wilson, Borden	Aug NQC	Net Seller
FRIANT_6_UNITS	34636	FRIANTDM	6.6	4.66	2	Wilson, Borden	Aug NQC	Net Seller
GUERNS_6_SOLAR	34461	GUERNSEY	12.5	7.37	1	Wilson	Aug NQC	Market
GUERNS_6_SOLAR	34461	GUERNSEY	12.5	7.37	2	Wilson	Aug NQC	Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon, Hanford		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon, Hanford		Market
HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	2	Wilson, Herndon	Aug NQC	Market
HELMPG_7_UNIT 1	34600	HELMS	18	407.00	1	Wilson	Aug NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	407.00	2	Wilson	Aug NQC	Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson	Aug NQC	Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson		Market
HURON_6_SOLAR	34557	HURON_DI	12.5	6.87	1	Wilson, Coalinga	Aug NQC	Market
HURON_6_SOLAR	34557	HURON_DI	12.5	6.87	2	Wilson, Coalinga	Aug NQC	Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	2.94	1	Wilson	Aug NQC	QF/Selfgen
JAYNE_6_WLSLR	34639	WESTLNDS	0.48	0.00	1	Wilson, Coalinga	Energy Only	Market
KANSAS_6_SOLAR	34666	KANSASS_S	12.5	0.00	F	Wilson	Energy Only	Market
KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 2	34343	KERCK1-2	6.6	0.00	2	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Wilson, Herndon	Aug NQC	Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon	Aug NQC	Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	23.71	1	Wilson, Herndon, Hanford	Aug NQC	Net Seller
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	Aug NQC	Market
KNGBRG_1_KBSLR1				0.00		Wilson	Not modeled Energy Only	Market
KNGBRG_1_KBSLR2				0.00		Wilson	Not modeled Energy Only	Market
KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Wilson	Energy Only	Market
LEPRFD_1_KANSAS	34680	Q636	12.5	13.85	1	Wilson, Hanford	Aug NQC	Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF	34219	MCCALL 4	12.5	0.58	QF	Wilson, Herndon	Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	5.82	1	Wilson	Aug NQC	MUNI
MENBIO_6_RENEW1	34339	CALRENEW	12.5	4.02	1	Wilson, Herndon	Aug NQC	Net Seller
MENBIO_6_UNIT	34334	BIO PWR	9.11	20.11	1	Wilson	Aug NQC	QF/Selfgen

MERCED_1_SOLAR1				0.00		Wilson	Not modeled Energy Only	Market
MERCED_1_SOLAR2				0.00		Wilson	Not modeled Energy Only	Market
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.15	1	Wilson	Aug NQC	Market
MNDOTA_1_SOLAR1	34311	NORTHSTAR	0.2	41.40	1	Wilson	Aug NQC	Market
ONLLPP_6_UNITS	34316	ONEILPMP	9.11	0.37	1	Wilson	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	22.00	1	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	22.00	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	22.00	3	Wilson, Herndon	Aug NQC	MUNI
PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	48.00	1	Wilson		Market
REEDLY_6_SOLAR				0.00		Wilson, Herndon, Reedley	Not modeled Energy Only	Market
S_RITA_6_SOLAR1				0.00		Wilson	Not modeled Energy Only	Market
SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	2.13	2	Wilson, Coalinga	Aug NQC	Market
SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	4.24	1	Wilson, Coalinga	Aug NQC	Market
SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	3.09	4	Wilson, Coalinga	Aug NQC	Market
SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	6.17	3	Wilson, Coalinga	Aug NQC	Market
SGREGY_6_SANGER	34646	SANGERCO	13.8	5.51	2	Wilson	Aug NQC	Market
SGREGY_6_SANGER	34646	SANGERCO	13.8	24.44	1	Wilson	Aug NQC	Market
STOREY_7_MDRCHW	34209	STOREY D	12.5	0.20	1	Wilson	Aug NQC	Net Seller
STROUD_6_SOLAR	34563	STROUD_D	12.5	6.57	1	Wilson, Herndon	Aug NQC	Market
STROUD_6_SOLAR	34563	STROUD_D	12.5	6.57	2	Wilson, Herndon	Aug NQC	Market
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	22.72	1	Wilson, Herndon	Aug NQC	QF/Selfgen
VEGA_6_SOLAR1	34314	Q548	34.5	0.00	1	Wilson	Energy Only	Market
WAUKNA_1_SOLAR	34696	CORCORANPV_S	21	18.00	1	Wilson, Herndon, Hanford	Aug NQC	Market
WAUKNA_1_SOLAR2	34677	Q558	21	14.78	1	Wilson, Herndon, Hanford	No NQC - Pmax	Market
WFRESN_1_SOLAR				0.00		Wilson	Energy Only	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson, Borden	Aug NQC	Market
WRGHTP_7_AMENGY	34207	WRIGHT D	12.5	0.30	QF	Wilson	Aug NQC	QF/Selfgen
BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.06	1	Wilson	Aug NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	1	Wilson, Coalinga		Market
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	7.80	1	Wilson		QF/Selfgen
NA	34485	FRESNOWW	12.5	1.10	3	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	3.10	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	3.10	2	Wilson	No NQC - hist. data	QF/Selfgen
New Unit	34603	JGBSWLT	12.5	0.00	ST	Wilson, Herndon	Energy Only	Market
New Unit	34653	Q526	33	0.00	1	Wilson, Coalinga	Energy Only	Market
New Unit	34699	RPS-N-034	0.39	0.00	1	Wilson, Herndon	Energy Only	Market
New Unit	34673	Q532	13.8	0.00	1	Wilson, Coalinga	Energy Only	Market
New Unit	34467	GIFFEN_DIST	12.5	10.00	1	Wilson, Herndon	No NQC - Pmax	Market

New Unit	34420	CORCORAN	115	19.00	WD	Wilson, Herndon, Hanford	No NQC - Pmax	Market
New Unit	34319	CHWCHLASLR	0.42	20.00	1	Wilson, Herndon	No NQC - Pmax	Market
New Unit	34335	Q723	0.32	50.00	1	Wilson, Borden	No NQC - Pmax	Market
New Unit	34683	RPS-N-055	0.8	100.00	1	Wilson	No NQC - Pmax	Market
New Unit	34340	RPS-N-059	0.8	200.00	1	Wilson	No NQC - Pmax	Market
New Unit	34300	Q550	36	0.00	1	Wilson	Energy Only	Market
New Unit	36205	Q648	36	0.00	1	Wilson	Energy Only	Market
New Unit	39604	PATRIOTB	0.32	0.00	1	Wilson	Energy Only	Market
New Unit	39601	PATRIOTA	0.32	0.00	1	Wilson	Energy Only	Market
New Unit	34644	Q679	0.48	20.00	1	Wilson	No NQC - Pmax	Market
New Unit	34649	Q965	0.36	20.00	1	Wilson	No NQC - Pmax	Market
New Unit	34623	Q678	0.5	60.00	1	Wilson, Coalinga	No NQC - Pmax	Market
New Unit	34688	Q272	0.56	123.00	1	Wilson	No NQC - Pmax	Market

Major new projects modeled:

1. Kerchhoff PH #2 - Oakhurst 115 kV Line
2. Warnerville-Wilson 230 kV reactor
3. Oro Loma 70 kV Area Reinforcement
4. New E2 substation
5. New North Merced 230/115 kV substation
6. New Mercy Spring 230/70 kV substation
7. Le Grand-Chowchilla 115 kV reconductoring
8. Panoche-Oro Loma 115 kV Reconductoring Project
9. Gates 500/230kV Transformer Bank #12

Critical Contingency Analysis Summary

Hanford Sub-area

The most critical contingency for the Hanford sub-area is the loss of the McCall-Kingsburg #2 115 kV line and Henrietta #3 230/115 kV transformer, which would thermally overload the McCall-Kingsburg #1 115 kV line. This limiting contingency establishes a local capacity need of 12 MW in 2021 (including 0 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

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

Coalinga Sub-area

The most critical contingency for the Coalinga sub-area is the loss of the Gates #5 230/70 kV transformer followed by the Panoche-Schindler #1 and #2 common tower contingency, which could cause voltage instability in the pocket. This limiting contingency establishes a local capacity need of 48 MW (including 2 MW of QF generation) in 2021 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

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

Borden Sub-area

The most critical contingency for the Borden sub-area is the loss of the Borden #4 230/70 kV transformer followed by the Friant-Coppermine 70 kV line, which could cause overload on the Borden #1 230/70 kV transformer. This limiting contingency establishes a local capacity need of 10 MW (including 0 MW of QF generation) in 2021 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

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

Reedley Sub-area

This sub-area has been eliminated due to New McCall-Reedley #2 115 kV line project.

Herndon Sub-area

This sub-area has been eliminated due to the new E2 substation that loops the Helms-Gregg #1 & #2 230kV lines and now injects Helms generation into Sanger, eliminating the need for this sub-area.

Wilson Sub-area

The most critical contingency for the Wilson sub-area is the loss of the Panoche-Tranquility #1 230kV line and the Gates-Mustang #1 230kV line, which could thermally overload the Oro Loma-El Nido 115 kV section of the Wilson-Oro Loma 115 kV line. This limiting contingency establishes a local capacity need of 1160 MW in 2021 (includes 64 MW of QF and 167 MW of Muni generation) as the generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Wilson sub-area is the loss of the Exchequer Generation unit following the loss of Warnervile-Wilson 230kV line, which could thermally overload the Oro Loma-El Nido 115 kV section of the Wilson-Oro Loma 115 kV line. This limiting contingency establishes a local capacity need of 731 MW in 2021 (includes 64 MW of QF and 167 MW of Muni generation) as the generation capacity necessary for reliable load serving capability within this sub-area.

The 2021 Fresno LCR base cases has been built with Path 15 at 1275 MW N-S due to historically seen overloads on Warnerville-Wilson 230 kV line. The overloads on the Panoche to Wilson 115 kV corridor are worst at Path 15 high S-N flows; therefore the LCR requirement herein is underestimated. For future years, after the installation of the Wilson reactor, the ISO will develop LCR base cases with a stressed Path 15 in the S-N direction in order to correctly quantify local requirement needs.

Effectiveness factors:

The following table has units within Fresno that are at least 4% effective.

Gen Bus	Gen Name	Gen ID	Eff Factor %

34300	RPS-N-138	1	12.24
34330	ELNIDO	1	12.24
34322	MERCEDFL	1	11.028
34301	CHOWCOGN	1	9.344
34305	CHWCHLA2	1	9.344
34335	RPS-N-071	1	8.385
34631	SJ2GEN	1	8.385
34633	SJ3GEN	1	8.385
34658	WISHON	1	8.385
34658	WISHON	2	8.385
34658	WISHON	3	8.385
34658	WISHON	4	8.385
34658	WISHON	SJ	8.385
34600	HELMS 1	1	7.461
34602	HELMS 2	1	7.461
34604	HELMS 3	1	7.461
34319	CHWCHLASLR	1	7.376
34308	KERCKHOF	1	7.058
34343	KERCK1-2	2	7.058
34344	KERCK1-1	1	7.058
34345	KERCK1-3	3	7.058
34624	BALCH 1	1	4.379
34616	KINGSRIV	1	4.079

Additional helpful effectiveness factors for Fresno area:

For most helpful procurement information please read procedure M-2210Z effectiveness factors at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

Overall the load forecast decreased by 272 MW. The LCR need has decreased by 728 MW due to load decrease and new identified limiting element. The 2021 Fresno LCR base cases has been built with Path 15 at 1275 MW N-S due to historically seen overloads on Warnerville-Wilson 230 kV line. The overloads on the Panoche to Wilson 115 kV corridor are worst at Path 15 high S-N flows; therefore the LCR requirement herein is underestimated. For future years, after the installation of the Wilson reactor, the ISO will develop LCR base cases with a stressed Path 15 in the S-N direction in order to correctly quantify local requirement needs.

Fresno Area Overall Requirements:

2021	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	64	167	3295	3526

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [15]	731	0	731
Category C (Multiple) [16]	1160	0	1160

7. Kern Area

<u>Area Definition</u>

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

1) 7th Standard-Kern 115 kV Line
2) Kern-Live Oak 115 kV
3) Kern-Magunden-Witco 115 kV
4) Charca-Famoso 115 kV (Normal Open)

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

1) Kern is out 7th Standard is in
2) Kern is out Live Oak is in
3) Kern and Magunden are out Kern Water Agency and Kern Oil Junction are in
4) Charca is out Famoso is in

Total 2021 busload within the defined area: 220 MW with -5 MW of AAEE and 1 MW of losses resulting in total load + losses of 216 MW.

Total units and qualifying capacity available in this area:

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

[16] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
7STDRD_1_SOLAR1	34709	7STNDRD	115	13.80		South Kern PP, Kern Oil	Not modeled Aug NQC	Market
DEXZEL_1_UNIT	35024	DEXEL +	9.11	20.00	1	South Kern PP, Kern Oil	Aug NQC	Net Seller
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	3.21	1	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	41.14	1	South Kern PP, Kern Oil	Aug NQC	Net Seller
MTNPOS_1_UNIT	35036	MT POSO	9.11	31.12	1	South Kern PP, Kern Oil	Aug NQC	Net Seller
VEDDER_1_SEKERN	35046	SEKR	9.11	11.96	1	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	0.00	1	South Kern PP, Kern Oil	Aug NQC	Net Seller
ULTOGL_1_POSO	35035	ULTR PWR	9.11	0.00	1	South Kern PP, Kern Oil	Retired	QF/Selfgen

Major new projects modeled:

1. Normal Open point at Famoso-Charca 115 kV
2. Kern PP 230 kV area reinforcement project
3. Kern PP 115 kV area reinforcement project
4. New Wheeler Ridge Junction substation
5. Midway-Kern PP 1, 3 &4 230 kV line capacity increase project

<u>Critical Contingency Analysis Summary</u>

West Park Sub-area

The West Park Sub area has been eliminated due to the normally open CB122 at Magunden and Kern PP 115 kV are reinforcement project.

Kern Oil Sub-area

The most critical contingency is the Kern PP-Magunden-Witco 115 kV line followed by Kern PP-7th Standard 115 kV line or vice versa resulting in the thermal overload of the Kern PP-Live Oak 115 kV line. This limiting contingency establishes a LCR of 105 MW in 2021 (includes 15 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the Kern PP-Magunden-Witco 115 kV line with PSE Live Oak generation out-of-service resulting in the thermal overload of the Kern PP-Live Oak 115 kV line. This limiting contingency establishes a LCR of 91 MW in 2021 (includes 15 MW of QF generation).

Effectiveness factors:

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

South Kern PP Sub-area

South Kern PP Sub-area has been eliminated due to Kern PP 230 kV area reinforcement and the Midway-Kern 1, 3 & 4 230 kV line capacity increase project.

Changes compared to last year's results:

Overall the load went down by 63 MW and the LCR requirement have gone down by 20 MW.

Kern Area Overall Requirements:

2021	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	15	106	121

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [17]	91	0	91
Category C (Multiple) [18]	105	0	105

8. LA Basin Area

<u>Area Definition</u>

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, and #3 230 kV Lines
2) Songsmesa - Talega #2 230 kV Lines

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

[18] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

3) Songsmesa - Capistrano #1 230 kV Lines
4) Lugo - Mira Loma #2 & #3 500 kV Lines
5) Lugo - Rancho Vista #1 500 kV Line
6) Sylmar - Eagle Rock 230 kV Line
7) Sylmar - Gould 230 kV Line
8) Vincent – Mira Loma #1 500 kV Line
9) Vincent - Mesa Cal #1 230 kV Line
10) Vincent - Rio Hondo #1 & #2 230 kV Lines
11) Devers - Red Bluff 500 kV #1 and #2 Lines
12) Mirage - Coachelv # 1 230 kV Line
13) Mirage - Ramon # 1 230 kV Line
14) Mirage - Julian Hinds 230 kV Line

The substations that delineate the LA Basin Area are:

1) San Onofre is in San Luis Rey is out
2) Songsmesa is in Talega is out
3) Songsmesa is in Capistrano is out
4) Mira Loma is in Lugo is out
5) Rancho Vista is in Lugo is out
6) Eagle Rock is in Sylmar is out
7) Gould is in Sylmar is out
8) Mira Loma is in Vincent is out
9) Mesa Cal is in Vincent is out
10) Rio Hondo is in Vincent is out
11) Devers is in Red Bluff is out
12) Mirage is in Coachelv is out
13) Mirage is in Ramon is out
14) Mirage is in Julian Hinds is out

The CEC-adopted demand forecast for 2021 is 19,260 MW[19] (this includes loads & losses and 838 MW AAEE). The total adjusted demand after including 238 MW peak shift adjustment[20] is 19,498 MW. A total of 19,506 MW of adjusted peak demand with 238 MW of peak shift adjustment was modeled for the study.

Total units and qualifying capacity available in the LA Basin area:

[19] CEC-adopted 2015 IEPR demand forecast for 2016-2026, January 2016, for Mid Demand Baseline Case with Low AAEE Savings.

[20] The CEC provided a total of 368 MW of peak shift for all of SCE area. It is estimated that about 238 MW is for the LA Basin based on the ratio of the behind-the-meter PV modeled in the LA Basin vs. entire SCE area (i.e., 640 MW / 989 MW). The CEC provided the amount of peak shift adjustment for all of SCE area for the 2015 IEPR demand forecast to the ISO in November 2016.

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ANAHM_2_CANYN1	25211	CanyonGT 1	13.8	49.40	1	Western		MUNI
ANAHM_2_CANYN2	25212	CanyonGT 2	13.8	48.00	2	Western		MUNI
ANAHM_2_CANYN3	25213	CanyonGT 3	13.8	48.00	3	Western		MUNI
ANAHM_2_CANYN4	25214	CanyonGT 4	13.8	49.40	4	Western		MUNI
ANAHM_7_CT	25208	DowlingCTG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	53.69	1	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	53.69	2	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	53.69	3	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	53.69	4	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	26.86	6	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	26.85	5	Western	Aug NQC	Net Seller
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	29309	BARPKGEN	13.8	47.00	1	Western		Market
BLAST_1_WIND	24839	BLAST	115	5.01	1	Eastern, Valley-Devers	Aug NQC	Wind
BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_1_NPALM1	25634	BUCKWIND	115	1.36		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
BUCKWD_1_QF	25634	BUCKWIND	115	1.94	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.10	W5	Eastern, Valley-Devers	Aug NQC	Wind
CABZON_1_WINDA1	29290	CABAZON	33	5.98	1	Eastern, Valley-Devers	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	17.98		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen
CENTER_6_PEAKER	29308	CTRPKGEN	13.8	47.00	1	Western		Market
CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	Eastern, Eastern Metro	Aug NQC	MUNI
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	4.98	2	Western, El Nido	Aug NQC	Net Seller
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	4.97	1	Western, El Nido	Aug NQC	Net Seller
CHINO_2_JURUPA				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_2_QF	24024	CHINO	66	5.35		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
CHINO_2_SASOLAR				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_2_SOLAR	24024	CHINO	66	0.47		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_2_SOLAR2				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_6_CIMGEN	24026	CIMGEN	13.8	26.11	D1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	26.63	D1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.19		Eastern, Eastern Metro	Not modeled Aug NQC	Market
COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	Eastern, Eastern Metro	Aug NQC	MUNI
CORONS_2_SOLAR				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern, Eastern Metro	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern, Eastern Metro	Not modeled	MUNI
DELAMO_2_SOLAR1				1.12		Western	Not modeled Aug NQC	Market
DELAMO_2_SOLAR2				1.31		Western	Not modeled Aug NQC	Market

DELAMO_2_SOLRC1				0.00		Western	Not modeled Energy Only	Market
DELAMO_2_SOLRD				0.00		Western	Not modeled Energy Only	Market
DEVERS_1_QF	25645	VENWIND	115	2.94	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.42	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.06	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.98	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	1.65	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.26	EU	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	24815	GARNET	115	1.24	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.11	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.66	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.49	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.46	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.22	W1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_SEPV05				0.00		Eastern, Valley-Devers	Energy Only	Market
DEVERS_1_SOLAR				0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
DEVERS_1_SOLAR1				0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
DEVERS_1_SOLAR2				0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
DMDVLY_1_UNITS	25425	ESRP P2	6.9	7.51		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.14	4	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.34	1	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.34	2	Eastern, Eastern Metro	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.01		Western	Not modeled Aug NQC	QF/Selfgen
ELSEGN_2_UN1011	28904	ELSEG5ST	18	195	5	Western, El Nido	Aug NQC	Market
ELSEGN_2_UN1011	28903	ELSEG6ST	18	68	6	Western, El Nido	Aug NQC	Market
ELSEGN_2_UN2021	28902	ELSEG7GT	18	195	7	Western, El Nido	Aug NQC	Market
ELSEGN_2_UN2021	28901	ELSEG8ST	18	68.68	8	Western, El Nido	Aug NQC	Market
ETIWND_2_CHMPNE				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.40		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_RTS010	24055	ETIWANDA	66	0.92		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS015	24055	ETIWANDA	66	1.17		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS017	24055	ETIWANDA	66	1.72		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS018	24055	ETIWANDA	66	0.92		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS023	24055	ETIWANDA	66	1.09		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS026	24055	ETIWANDA	66	1.50		Eastern, Eastern Metro	Not modeled Aug NQC	Market

ETIWND_2_RTS027	24055	ETIWANDA	66	1.50		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_SOLAR	24055	ETIWANDA	66	0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
ETIWND_2_UNIT1	24055	ETIWANDA	66	14.71		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	46.00	1	Eastern, Eastern Metro		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	1.62	1	Eastern, Eastern Metro	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.67		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
GARNET_1_SOLAR	24815	GARNET	115	0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
GARNET_1_SOLAR2	24815	GARNET	115	2.77		Eastern, Valley-Devers	Not modeled Aug NQC	Market
GARNET_1_UNITS	24815	GARNET	115	0.66	G1	Eastern, Valley-Devers	Aug NQC	Market
GARNET_1_UNITS	24815	GARNET	115	0.48	G3	Eastern, Valley-Devers	Aug NQC	Market
GARNET_1_UNITS	24815	GARNET	115	0.23	G2	Eastern, Valley-Devers	Aug NQC	Market
GARNET_1_WIND	24815	GARNET	115	0.29	PC	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.46	W2	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.46	W3	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WT3WND	24815	GARNET	115	0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
GARNET_2_WIND1				1.79		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
GARNET_2_WIND4				1.54		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.07	1	Western		MUNI
GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	29005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	29006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	0.00	1	Western	Mothballed	Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	0.00	HP	Western	Mothballed	Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	0.00	LP	Western	Mothballed	Market
HINSON_6_CARBGN	24020	CARBGEN1	13.8	14.68	1	Western	Aug NQC	Market
HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.68	1	Western	Aug NQC	Market
HINSON_6_LBECH1	24170	LBEACH12	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH12	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH34	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24171	LBEACH34	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	25.73	D1	Western	Aug NQC	QF/Selfgen
INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	Eastern, Valley-Devers		Market
INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	Eastern, Valley-Devers		Market
INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	Eastern, Valley-Devers		Market
INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	Eastern, Valley, Valley-Devers	Aug NQC	Market
INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	Eastern, Valley, Valley-Devers	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24337	VENICE	13.8	1.38	1	Western, El Nido	Aug NQC	MUNI
LAFRES_6_QF	24073	LA FRESA	66	0.00		Western, El Nido	Not modeled Aug NQC	QF/Selfgen

LAGBEL_6_QF	24075	LAGUBELL	66	9.79		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	48.00	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.30		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	0.04		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.03		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_ONTARO				2.38		Eastern, Eastern Metro	Energy Only	Market
MIRLOM_2_RTS032				0.75		Eastern, Eastern Metro	Not modeled Aug NQC	Market
MIRLOM_2_RTS033				0.75		Eastern, Eastern Metro	Not modeled Aug NQC	Market
MIRLOM_2_TEMESC				2.13		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	27.66	1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	Eastern, Eastern Metro		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.60		Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.20	1	Eastern, Eastern Metro	Aug NQC	MUNI
MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.19	2	Eastern, Eastern Metro	Aug NQC	MUNI
MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.19	3	Eastern, Eastern Metro	Aug NQC	MUNI
MTWIND_1_UNIT 1	29060	MOUNTWND	115	4.07	S1	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 2	29060	MOUNTWND	115	1.88	S2	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 3	29060	MOUNTWND	115	1.64	S3	Eastern, Valley-Devers	Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	6.98	S1	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C1	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C2	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C3	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C4	Western	Aug NQC	Market
OLINDA_2_QF	24211	OLINDA	66	0.11	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24211	OLINDA	66	0.05		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.19		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
PADUA_2_SOLAR1	24111	PADUA	66	0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
PADUA_6_MWDSDM	24111	PADUA	66	3.71		Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	0.48		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern, Eastern Metro	Not modeled Aug NQC	Market
PANSEA_1_PANARO	25640	PANAERO	115	0.26	QF	Eastern, Valley-Devers	Aug NQC	Wind
PWEST_1_UNIT				0.12		Western	Not modeled Aug NQC	Market
RENWD_1_QF	25636	RENWIND	115	2.47	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
RHONDO_2_QF	24213	RIOHONDO	66	0.40		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Net Seller
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	Eastern, Eastern Metro		MUNI

RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	Eastern, Eastern Metro		MUNI
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern, Eastern Metro		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern, Eastern Metro		MUNI
RVSIDE_6_SOLAR1	24244	SPRINGEN	13.8	7.02		Eastern, Eastern Metro	Not modeled Aug NQC	Market
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern, Eastern Metro		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	5.63	1	Western	Aug NQC	Market
SANWD_1_QF	25646	SANWIND	115	1.75	Q2	Eastern, Valley-Devers	Aug NQC	Wind
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.06		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_REDLND	24214	SANBRDNO	66	0.66		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS005	24214	SANBRDNO	66	1.28		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS007	24214	SANBRDNO	66	1.15		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS011	24214	SANBRDNO	66	2.62		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS013	24214	SANBRDNO	66	2.62		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS016	24214	SANBRDNO	66	1.12		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS048	24214	SANBRDNO	66	0.00		Eastern, West of Devers, Eastern Metro	Not modeled Energy Only	Market
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.00		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	0.64		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SENTNL_2_CTG1	29101	TOT032G1	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG2	29102	TOT032G2	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG3	29103	TOT032G3	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG4	29104	TOT032G4	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG5	29105	TOT032G5	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG6	29106	TOT032G6	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG7	29107	TOT032G7	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG8	29108	TOT032G8	13.8	91	1	Eastern, Valley-Devers		Market
TIFFNY_1_DILLON				4.01		Western	Not modeled Aug NQC	Wind
TRNSWD_1_QF	25637	TRANWIND	115	4.66	QF	Eastern, Valley-Devers	Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	1.52		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_RTS044	24160	VALLEYSC	115	3.90		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market

VALLEY_5_SOLAR1	24160	VALLEYSC	115	0.00		Eastern, Valley, Valley-Devers	Not modeled Energy Only	Market
VALLEY_5_SOLAR2	24160	VALLEYSC	115	14.97		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VALLEY_7_BADLND	24160	VALLEYSC	115	0.30		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	2.30		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	3.40		Western	Not modeled Aug NQC	MUNI
VISTA_2_RIALTO	24901	VSTA	230	0.00		Eastern, Eastern Metro	Energy Only	Market
VISTA_2_RTS028	24901	VSTA	230	2.25		Eastern, Eastern Metro	Not modeled Aug NQC	Market
VISTA_6_QF	24902	VSTA	66	0.11	1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
WALCRK_2_CTG1	29201	EME WCG1	13.8	96	1	Western		Market
WALCRK_2_CTG2	29202	EME WCG2	13.8	96	1	Western		Market
WALCRK_2_CTG3	29203	EME WCG3	13.8	96	1	Western		Market
WALCRK_2_CTG4	29204	EME WCG4	13.8	96	1	Western		Market
WALCRK_2_CTG5	29205	EME WCG5	13.8	96.65	1	Western		Market
WALNUT_2_SOLAR				0.00		Western	Not modeled Energy Only	Market
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.73	D1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	0.00		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	5.08		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	29061	WHITEWTR	33	3.97	1	Eastern, Valley-Devers	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Net Seller
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	15.20	1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	29.50	1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	29338	CLRWTRCT	13.8	20.70	G1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	29953	SIGGEN	13.8	18.60	D1	Western	No NQC - Pmax	QF/Selfgen
NA	29951	REFUSE	13.8	9.80	D1	Western	No NQC - Pmax	QF/Selfgen
NA	24341	COYGEN	13.8	6.30	1	Western	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	5.80	1	Western	No NQC - hist. data	QF/Selfgen

NA	24324	SANIGEN	13.8	1.40	D1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	1.40	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24329	MOBGEN2	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	29021	WINTEC6	115	0.00	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29260	ALTAMSA4	115	0.00	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29340	CLRWTRST	13.8	0.00	S1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
New	90002	ALMT-ST1	18	240.00	X3	Western	No NQC - Pmax	Market
New	90005	HUNT-ST!	18	240.00	X3	Western	No NQC - Pmax	Market
New	90003	HUNT-GT1	18	202.00	X1	Western	No NQC - Pmax	Market
New	90004	HUNT-GT2	18	202.00	X2	Western	No NQC - Pmax	Market
New	90000	ALMT-GT1	18	200.00	X1	Western	No NQC - Pmax	Market
New	90001	ALMT-GT2	18	200.00	X2	Western	No NQC - Pmax	Market
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	0.00	1	Western	Retired by 2021	Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	0.00	2	Western	Retired by 2021	Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	0.00	3	Western	Retired by 2021	Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	0.00	4	Western	Retired by 2021	Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	0.00	5	Western	Retired by 2021	Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	0.00	6	Western	Retired by 2021	Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	0.00	4	Western, El Nido	Retired	Market
ETIWND_7_UNIT 3	24052	MTNVIST3	18	0.00	3	Eastern, Eastern Metro	Assumed retirement by age	Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	0.00	4	Eastern, Eastern Metro	Assumed retirement by age	Market
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	0.00	1	Western	Retired by 2021	Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	0.00	2	Western	Retired by 2021	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	0.00	5	Western	Retired by 2021	Market
REDOND_7_UNIT 6	24122	REDON6 G	18	0.00	6	Western	Retired by 2021	Market
REDOND_7_UNIT 7	24123	REDON7 G	20	0.00	7	Western	Retired by 2021	Market
REDOND_7_UNIT 8	24124	REDON8 G	20	0.00	8	Western	Retired by 2021	Market
SONGS_7_UNIT 2	24129	S.ONOFR2	22	0.00	R2	None	Retired	Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	0.00	R3	None	Retired	Nuclear

Major new projects modeled:

1. Vincent-Mira Loma 500 kV (part of Tehachapi Upgrade)
2. East County 500kV Substation (ECO)
3. Mesa Loop-In Project and South of Mesa 230 kV line upgrades

4. Imperial Valley Phase Shifting Transformers (2x400 MVA)
5. Delaney – Colorado River 500 kV Line
6. Hassayampa – North Gila #2 500 kV Line (APS)
7. Bay Blvd. Substation Project
8. Sycamore – Penasquitos 230 kV Line
9. Talega Synchronous Condensers (2x225 MVAR)
10. San Luis Rey Synchronous Condensers (2x225 MVAR)
11. San Onofre Synchronous Condenser (225 MVAR)
12. Santiago Synchronous Condenser (225 MVAR)
13. Bypass series capacitors on the ECO-Miguel and Ocotillo-Suncrest 500kV lines
14. West of Devers 230 kV line upgrades
15. Carlsbad Energy Center (500 MW)
16. Pio Pico peakers (300 MW)
17. Battery energy storage system projects in the LA Basin and San Diego area (CPUC-approved projects related to the Aliso Canyon gas storage constraint)

<u>Critical Contingency Analysis Summary</u>

El Nido Sub-area:

The most critical contingency is the loss of La Fresa – El Nido #1 and #2 230 kV lines, which would result in loading concerns for the La Fresa – La Cienega 230 kV line. This limiting contingency establishes a local capacity need of 359 MW (includes 1 MW of QF, 1 MW of MUNI generation, 7 MW of 20-minute demand response and 20 MW of long-term procurement plan preferred resources) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has effectiveness factors for resources in this sub-area.

Gen Bus	Gen Name	MW Eff Fctr (%)
24022	CHEVGEN1	100
24023	CHEVGEN2	100
28903	ELSEG6ST	100
28904	ELSEG5ST	100

28901	ELSEG8ST	100
28902	ELSEG7GT	100
24337	VENICE	100
24094	MOBGEN	0
24329	MOBGEN2	0
24330	OUTFALL1	0
24331	OUTFALL2	0
24332	PALOGEN	0

Western LA Basin Sub-area:

The most limiting contingency is the loss of Mesa – Redondo 230 kV line, system re-adjusted, followed by the loss of Mesa – Lighthipe 230 kV line. This N-1-1 (P6) contingency causes an overloading concern on the Mesa – Laguna Bell No. 1 230kV line. This limiting contingency requires a local capacity need of 4069 MW (includes 201 MW of QF, 4 MW of wind and 582 MW of MUNI generation, 432 MW preferred resources and 162 MW of 20-minute “fast” demand response) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness factors.

Resource Locations	Effectiveness Factor (%)
REFUSE 13.8 #D1	-34.52
MALBRG1G 13.8 #C1	-34.42
ELSEG6ST 13.8 #6	-26.66
ELSEG5GT 16.5 #5	-26.64
VENICE 13.8 #1	-26.22
MOBGEN1 13.8 #1	-26.18
PALOGEN 13.8 #D1	-26.18
ARCO 1G 13.8 #1	-23.13
HARBOR G 13.8 #1	-23.03
THUMSGEN 13.8 #1	-23.03
CARBGEN1 13.8 #1	-23.02
SERRFGEN 13.8 #D1	-23.02
ICEGEN 13.8 #D1	-22.33
ALMITOSW 66.0 #I3	-18.01
ALAMTX1 18.0 #X1	-17.93
CTRPKGEN 13.8 #1	-17.51
SIGGEN 13.8 #D1	-17.51

BARRE	66.0 #m3	-12.76
BARPKGEN	13.8 #1	-12.71
RIOHONDO	66.0 #l8	-12.5
WALNUT	66.0 #l3	-12.29
OLINDA	66.0 #1	-12.07
EME WCG1	13.8 #1	-12
BREAPWR2	13.8 #C4	-11.98
ELLIS	66.0 #l7	-11.98
JOHANNA	66.0 #l5	-11.42
SANTIAGO	66.0 #l8	-10.63
DowlingCTG	13.8 #1	-9.62
CanyonGT 1	13.8 #1	-9.58
VILLA PK	66.0 #l2	-9.29

There are numerous other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area/area and have slightly 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 facilitate more informed procurement.

West of Devers Sub-area:

There are no local capacity requirements due to implementation of the Mesa Loop-in as well as West of Devers reconductoring projects.

Valley-Devers Sub-area:

There are no local capacity requirements due to implementation of the Colorado River-Delaney 500 kV line project.

Valley Sub-area:

There are no local capacity requirements due to implementation of the Colorado River-Delaney 500 kV line project.

Eastern LA Basin Sub-area:

The most critical contingency is the loss of the Alberhill - Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines, which would result in voltage instability. This limiting contingency establishes a local capacity need of about 2829 MW (this includes 198 MW of QF, 37 MW of wind and 593 MW of Muni generation, as well as 160 MW of 20-minute demand response in the area) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

LA Basin Overall:

The total LCR need for the overall LA Basin is the sum of the LCR needs from the Western LA Basin and the Eastern LA Basin sub-areas. This resulted in a total LCR need of 6898 MW (this includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, as well as 322 MW of 20-minute demand response and 432 MW of long-term procurement plan preferred resources) for the overall LA Basin.

Combined Overall LA Basin and San Diego:

The critical Category C contingency for the overall LA Basin and San Diego sub-area is the overlapping (N-1-1 or NERC P6) contingency of the Mesa-Redondo 230 kV line, system readjustment, followed by the Mesa-Lighthipe 230 kV line, resulting in thermal limiting constraint, for the combined LA Basin and San Diego sub-area. This contingency could cause loading concerns for the Mesa-Laguna Bell 230 kV line. This limiting contingency establishes an overall total local capacity need for the combined LA Basin/San Diego sub-area of 9412 MW in 2021 as follows: 6898 MW in the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, 432 MW of long-term procurement plan preferred resources, as well as 322 MW of 20-minute demand response) and 2514 MW in the San Diego subarea (includes 103 MW of QF generation and 5 MW of wind) as the minimum capacity necessary for reliable load serving capability within these areas.

The critical Category B contingency for the overall LA Basin and San Diego sub-area is the same as the LA Basin/San Diego/Imperial Valley need; the overlapping G-1/N-1 outage (NERC P3 category) of Termoelectrica de Mexicali (TDM) combined cycle plant (593 MW), followed by an N-1 contingency of the Imperial Valley – North Gila 500 kV line. This overlapping contingency could cause thermal overload on the "S" line (El Centro – Imperial Valley 230 kV line) between Imperial Irrigation District (IID) and SDG&E. This limiting contingency establishes a total local capacity need 11054 MW of which 9211 MW is located in the combined LA Basin/San Diego sub-area as follows: 6697 MW in the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, 432 MW of long-term procurement plan preferred resources, as well as 322 MW of 20-minute demand response) and 2514 MW in the San Diego sub-area (includes 103 MW of QF generation and 5 MW of wind) as the minimum capacity necessary for reliable load serving capability within these areas.

Changes compared to last year's results:

Compared with 2020 the load forecast is down by 1258 MW. The LA Basin LCR need has decreased by 2331 MW, due to load forecast decreases, new transmission projects and increases in need in the San Diego-Imperial Valley area. The LA Basin available Qualifying Capacity has decreased by 3174 MW as a combination of projected resource retirements and new resource interconnections.

LA Basin Overall Requirements:

2021	QF (MW)	Wind (MW)	Muni (MW)	Battery St. (MW)	Preferred Res. (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	399	41	1175	62	431	5408	7795

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[21]	6697	0	6697
Category C (Multiple)[22]	6898	0	6898

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

[22] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

9. Big Creek/Ventura Area

Area Definition

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

1) Antelope #1 500/230 kV Transformer
2) Antelope #2 500/230 kV Transformer
3) Sylmar - Pardee 230 kV #1 and #2 Lines
4) Vincent - Pardee 230 kV #2 Line
5) Vincent - Santa Clara 230 kV Line

The substations that delineate the Big Creek/Ventura Area are:

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

The CEC-adopted demand forecast for 2021 is 3,798 MW[23] (this includes loads & losses and 171 MW AAEE). The total adjusted demand after including 77 MW peak shift adjustment[24] is 3,875 MW. A total of 3,849 MW of adjusted peak demand[25] was modeled for the study.

Total units and qualifying capacity available in the Big Creek/Ventura area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ACACIA_6_SOLAR	29878	ACACIA_G	0.48	0.00	EQ	Big Creek	Energy Only	Market
ALAMO_6_UNIT	25653	ALAMO SC	13.8	15.07	1	Big Creek	Aug NQC	MUNI

[23] CEC-adopted 2015 IEPR demand forecast for 2016-2026, January 2016, for Mid Demand Baseline Case with Low AAEE Savings.

[24] The CEC provided a total of 989 MW of peak shift for all of SCE area. It is estimated that about 77 MW is for the Big Creek-Ventura area based on the ratio of the behind-the-meter PV modeled in the Big Creek-Ventura vs. entire SCE area (i.e., 208 MW / 989 MW). The CEC provided the amount of peak shift adjustment for all of SCE area for the 2015 IEPR demand forecast to the ISO in November 2016.

[25] This includes 369 MW of pump loads. This calculation is without the Saugus load (which is geographically located in the LA Basin) to be consistent with the CEC demand forecast for the geographic Big Creek-Ventura area.

BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal	Aug NQC	Market
DELSUR_6_DRYFRB				3.46		Big Creek	Not modeled Aug NQC	Market
DELSUR_6_SOLAR1				4.49		Big Creek	Not modeled Aug NQC	Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	16.86	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	16.86	2	Big Creek	Pumps	MUNI

EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	4	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.86	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.86	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.86	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.86	14	Big Creek	Pumps	MUNI
GLOW_6_SOLAR	29896	APPINV	0.42	0.00	EQ	Big Creek	Energy Only	Market
GOLETA_2_QF	24057	GOLETA	66	0.08		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_ELLWOD	29004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24362	EXGEN2	13.8	0.47	G1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
GOLETA_6_EXGEN	24326	EXGEN1	13.8	0.32	S1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	0.68		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
GOLETA_6_TAJIGS	24057	GOLETA	66	2.90		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
LEBECS_2_UNITS	29053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29055	PSTRIAS2	18	78.90	S2	Big Creek	Aug NQC	Market
LITLRK_6_SEPV01				0.00		Big Creek	Not modeled Energy Only	Market
LITLRK_6_SOLAR1				3.45		Big Creek	Not modeled Aug NQC	Market
LITLRK_6_SOLAR4				2.08		Big Creek	Not modeled Aug NQC	Market
LNCSTR_6_SOLAR				7.02		Big Creek	Not modeled Aug NQC	Market
MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	Ventura, S.Clara, Moorpark		Market
MOORPK_2_CALABS	24099	MOORPARK	230	4.19		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	29952	CAMGEN	13.8	26.81	D1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	2.12		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
NEENCH_6_SOLAR	29900	ALPINE_G	0.48	50.05	EQ	Big Creek	Aug NQC	Market
OASIS_6_SOLAR2				13.85		Big Creek	Not modeled Aug NQC	Market
OMAR_2_UNIT 1	24102	OMAR 1G	13.8	77.10	1	Big Creek		Net Seller
OMAR_2_UNIT 2	24103	OMAR 2G	13.8	77.25	2	Big Creek		Net Seller
OMAR_2_UNIT 3	24104	OMAR 3G	13.8	77.25	3	Big Creek		Net Seller
OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	Big Creek		Net Seller

OSO_6_NSPIN	25614	OSO A P	13.2	2.25	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.25	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.25	3	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.25	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	6	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	25.70	1	Big Creek, Vestal	Aug NQC	Market
PANDOL_6_UNIT	24113	PANDOL	13.8	20.94	2	Big Creek, Vestal	Aug NQC	Market
PLAINV_6_BSOLAR				0.00		Big Creek	Not modeled Energy Only	Market
RECTOR_2_KAWEAH	24212	RECTOR	66	0.00		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	0.31		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	0.41		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	0.00		Big Creek, Rector, Vestal	Not modeled	Market
RSMSLR_6_SOLAR1				16.81		Big Creek	Not modeled Aug NQC	Market
RSMSLR_6_SOLAR2				15.57		Big Creek	Not modeled Aug NQC	Market
SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		Big Creek	Not modeled Energy Only	Market
SAUGUS_6_MWDFTH	24135	SAUGUS	66	7.36		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	19.47	D1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	0.78		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_CHIQCN	24135	SAUGUS	66	3.96		Big Creek	Not modeled Aug NQC	Market
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.34		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	34.62	D1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.22	D1	Ventura, S.Clara, Moorpark	Aug NQC	Market
SNCLRA_6_QF				0.00		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	13.61	D1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.23		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.00		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.29		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.05	1	Big Creek	Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.05	2	Big Creek	Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.05	3	Big Creek	Aug NQC	Market

SUNSHN_2_LNDFL	29954	WDT273	13.7	3.04	4	Big Creek	Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.04	5	Big Creek	Aug NQC	Market
SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	75.52	1	Big Creek	Aug NQC	Net Seller
SYCAMR_2_UNIT 2	24144	SYCCYN2G	13.8	85.00	2	Big Creek	Aug NQC	Net Seller
SYCAMR_2_UNIT 3	24145	SYCCYN3G	13.8	75.25	3	Big Creek	Aug NQC	Net Seller
SYCAMR_2_UNIT 4	24146	SYCCYN4G	13.8	85.00	4	Big Creek	Aug NQC	Net Seller
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.12	D1	Big Creek	Aug NQC	Net Seller
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.12	D2	Big Creek	Aug NQC	Net Seller
VESTAL_2_KERN	24372	KR 3-1	11	0.22	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_2_KERN	24373	KR 3-2	11	0.22	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_2_RTS042				0.00		Big Creek, Vestal	Not modeled Energy Only	Market
VESTAL_2_WELLHD	24116	WELLGEN	13.8	49.00	1	Big Creek, Vestal		Market
VESTAL_6_QF	24152	VESTAL	66	0.31		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	27.87	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	24152	VESTAL	66	5.63		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	MUNI
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	MUNI
APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	Big Creek	No NQC - hist. data	Market
APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	Big Creek	No NQC - hist. data	Market
APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	Big Creek	No NQC - hist. data	Market
NA	24370	KAWGEN	13.8	17.00	1	Big Creek, Rector, Vestal	No NQC - hist. data	Market
NA	24340	CHARMIN	13.8	15.00	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market
VESTAL_6_WDFIRE	29008	LAKEGEN	13.8	11.00	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
New Unit	29884	DAWNGEN	0.82	20.00	EQ	Big Creek	No NQC - Pmax	Market
New Unit	29888	TWILGHTG	0.82	20.00	EQ	Big Creek	No NQC - Pmax	Market
New Unit	29918	VLYFLR_G	0.2	20.00	EQ	Big Creek	No NQC - Pmax	Market
New Unit	24089	MANDLY1G	13.8	131.00	X1	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market
New Unit	24090	MANDLY2G	13.8	131.00	X2	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market
New Unit	29952	CAMGEN	14.2	28.00	D1	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market
New Unit	29954	WDT273	66	10.00	EQ	Big Creek	No NQC - Pmax	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	0.00	1	Ventura, S.Clara, Moorpark	Retired by 2021	Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	0.00	2	Ventura, S.Clara, Moorpark	Retired by 2021	Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	0.00	3	Ventura, S.Clara, Moorpark	Retired by 2021	Market
ORMOND_7_UNIT 1	24107	ORMOND1G	26	0.00	1	Ventura, Moorpark	Retired by 2021	Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	0.00	2	Ventura, Moorpark	Retired by 2021	Market

Major new projects modeled:

None

Critical Contingency Analysis Summary

Rector Sub-area:

The most critical contingency is the loss of the Rector - Vestal 230 kV line with the Eastwood unit out of service, which could thermally overload the remaining Rector - Vestal 230 kV line. This limiting contingency establishes a local capacity need of 429 MW (includes 1 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Rector sub-area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24370	KAWGEN	1	51
24306	B CRK1-1	1	46
24306	B CRK1-1	2	46
24307	B CRK1-2	3	46
24307	B CRK1-2	4	46
24319	EASTWOOD	1	46
24323	PORTAL	1	46
24308	B CRK2-1	1	45
24308	B CRK2-1	2	45
24309	B CRK2-2	3	45
24309	B CRK2-2	4	45
24310	B CRK2-3	5	45
24310	B CRK2-3	6	45
24315	B CRK 8	81	45
24315	B CRK 8	82	45
24311	B CRK3-1	1	45
24311	B CRK3-1	2	45
24312	B CRK3-2	3	45
24312	B CRK3-2	4	45
24313	B CRK3-3	5	45
24317	MAMOTH1G	1	45
24318	MAMOTH2G	2	45
24314	B CRK 4	41	43
24314	B CRK 4	42	43

Vestal Sub-area:

The most critical contingency is the loss of the Magunden - Vestal 230 kV line with the Eastwood unit out of service, which could thermally overload the remaining Magunden - Vestal 230 kV line. This limiting contingency establishes a local capacity need of 746 MW (includes 46 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Vestal sub-area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24113	PANDOL	1	65
24113	PANDOL	2	65
24116	WELLGEN	1	65
24150	ULTRAGEN	1	65
24372	KR 3-1	1	65
24373	KR 3-2	2	65
28019	WDT190G	1	65
29008	LAKEGEN	1	65
24370	KAWGEN	1	50
24306	B CRK1-1	1	44
24306	B CRK1-1	2	44
24307	B CRK1-2	3	44
24307	B CRK1-2	4	44
24319	EASTWOOD	1	44
24323	PORTAL	1	44
24308	B CRK2-1	1	44
24308	B CRK2-1	2	44
24309	B CRK2-2	3	44
24309	B CRK2-2	4	44
24310	B CRK2-3	5	44
24310	B CRK2-3	6	44
24315	B CRK 8	81	44
24315	B CRK 8	82	44
24311	B CRK3-1	1	44
24311	B CRK3-1	2	44
24312	B CRK3-2	3	44
24312	B CRK3-2	4	44
24313	B CRK3-3	5	44
24317	MAMOTH1G	1	44

24318	MAMOTH2G	2	44
24314	B CRK 4	41	42
24314	B CRK 4	42	42

Santa Clara Sub-area:

The most critical contingency is the loss of the Pardee - Santa Clara 230 kV line followed by the loss of Moorpark - Santa Clara 230 kV #1 and #2 lines, which would cause voltage collapse. This limiting contingency establishes a local capacity need of 253 MW (includes 91 MW QF generation, 5 MW of battery storage and 2 MW of preffered resources) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Moorpark Sub-area:

The most critical contingency is the loss of the Moorpark - Pardee 230 kV #3 line followed by the loss of the Moorpark - Pardee 230 kV #1 and #2 lines, which will cause voltage collapse. This limiting contingency establishes a local capacity need of 536 MW (includes 93 MW QF generation, 5 MW of battery storage and 12 MW of preffered resources) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo - Victorville 500 kV line followed by loss of one of the Sylmar - Pardee 230 kV line, which would thermally overload the remaining Sylmar - Pardee 230 kV line.This limiting contingency establishes a local capacity need of 2398 MW (includes 145 MW of QF and 372 MW of MUNI generation, 5

MW of battery storage and 12 MW of preffered resources) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of Sylmar - Pardee #1 (or # 2) line with Pastoria power plant (CCGT) out of service, which could thermally overload the remaining Sylmar - Pardee #2 or #1 230 kV line. This limiting contingency establishes a local capacity need of 2325 MW (includes 145 MW of QF and 372 MW of MUNI generation, 5 MW of battery storage and 12 MW of preffered resources).

Effectiveness factors:

The following table has effectiveness factors to the most critical contingency.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24009	APPGEN1G	1	31
24010	APPGEN2G	2	31
24118	PITCHGEN	D1	31
24148	TENNGEN1	D1	31
24149	TENNGEN2	D2	31
24361	APPGEN3G	3	31
29954	WDT273	EQ	31
24107	ORMOND1G	1	30
24108	ORMOND2G	2	30
25651	WARNE1	1	28
25652	WARNE2	1	28
24089	MANDLY1G	1	26
24090	MANDLY2G	2	26
24110	OXGEN	D1	26
24119	PROCGEN	D1	26
24127	S.CLARA	1	26
24159	WILLAMET	D1	26
24222	MANDLY3G	3	26
24326	EXGEN1	S1	26
24340	CHARMIN	1	26
24362	EXGEN2	G1	26
29004	ELLWOOD	1	26
29306	MCGPKGEN	1	26
29952	CAMGEN	D1	26
25653	ALAMO SC	1	26
29051	PSTRIAG1	G1	25
29052	PSTRIAG2	G2	25
29053	PSTRIAS1	S1	25

29054	PSTRIAG3	G3	25
29055	PSTRIAS2	S2	25
24102	OMAR 1G	1	21
24103	OMAR 2G	2	21
24104	OMAR 3G	3	21
24105	OMAR 4G	4	21
24113	PANDOL	1	21
24113	PANDOL	2	21
24116	WELLGEN	1	21
24143	SYCCYN1G	1	21
24144	SYCCYN2G	2	21
24145	SYCCYN3G	3	21
24146	SYCCYN4G	4	21
24150	ULTRAGEN	1	21
24306	B CRK1-1	1	21
24306	B CRK1-1	2	21
24307	B CRK1-2	3	21
24307	B CRK1-2	4	21
24308	B CRK2-1	1	21
24308	B CRK2-1	2	21
24309	B CRK2-2	3	21
24309	B CRK2-2	4	21
24310	B CRK2-3	5	21
24310	B CRK2-3	6	21
24311	B CRK3-1	1	21
24311	B CRK3-1	2	21
24312	B CRK3-2	3	21
24312	B CRK3-2	4	21
24313	B CRK3-3	5	21
24314	B CRK 4	41	21
24314	B CRK 4	42	21
24315	B CRK 8	81	21
24315	B CRK 8	82	21
24317	MAMOTH1G	1	21
24318	MAMOTH2G	2	21
24319	EASTWOOD	1	21
24323	PORTAL	1	21
24370	KAWGEN	1	21
24372	KR 3-1	1	21
24373	KR 3-2	2	21
28019	WDT190G	1	21
29008	LAKEGEN	1	21
29900	ALPINE_G	EQ	17
24422	PALMDALE	1	8
29884	DAWNGEN	EQ	8

29888	TWILGHTG	EQ	8
29896	APPINV	EQ	8
29918	VLYFLR_G	EQ	8

Changes compared to last year's results:

Compared with 2020 the load forecast is down by 996 MW and the LCR need has decreased by 200 MW, due to load forecast decrease and effectiveness of projected resource retirements. The Qualifying Capacity in the area has decreased by 1858 MW as a combination of projected resource retirement and new resource development.

Big Creek/Ventura Overall Requirements:

2021	QF (MW)	Muni (MW)	Baterry St. (MW)	Preffered Res. (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	145	372	5	12	3143	3677

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[26]	2325	0	2325
Category C (Multiple)[27]	2398	0	2398

10. San Diego-Imperial Valley Area

Area Definition

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

1) Imperial Valley – North Gila 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line

[26] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[27] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

4) San Onofre - San Luis Rey #2 230 kV Line
5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega 230 kV Line
7) San Onofre – Capistrano 230 kV Line
8) Imperial Valley – El Centro 230 kV Line
9) Imperial Valley PFC – La Rosita 230 kV Line

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

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

The CEC-adopted demand forecast for 2021 is 4,708 MW[28] (this includes loads & losses and 254 MW AAEE). The total adjusted demand after including 272 MW peak shift adjustment[29] is 4,980 MW. A total of 4,980 MW of adjusted peak demand including this peak shift was modeled for the study.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	48.00	1	San Diego, Border		Market
BREGGO_6_DEGRSL				4.36		San Diego	Not modeled Aug NQC	Market
BREGGO_6_SOLAR	22082	BR GEN1	0.21	20.46	1	San Diego	Aug NQC	Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.83	1	San Diego	Aug NQC	Market
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.25	1	San Diego	Aug NQC	Market
CHILLS_1_SYCENG	22120	CARLTNHS	138	0.54	1	San Diego	Aug NQC	QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.54		San Diego	Not modeled Aug NQC	Net Seller
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.52	2	San Diego	Aug NQC	QF/Selfgen
CNTNLA_2_SOLAR1	23463	DW GEN3&4	0.33	97.02	1	None	Aug NQC	Market
CNTNLA_2_SOLAR2	23463	DW GEN3&4	0.33	0.00	2	None	Energy Only	Market
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.12	1	San Diego	Aug NQC	Market
CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	48.54	G2	None	Aug NQC	Market

[28] CEC-adopted 2015 IEPR demand forecast for 2016-2026, January 2016, for Mid Demand Baseline Case with Low AAEE Savings.
[29] The CEC provided this amount of peak shift adjustment for the 2015 IEPR demand forecast to the ISO in November 2016.

CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	48.54	G1	None	Aug NQC	Market
CRELMN_6_RAMON1				1.53		San Diego	Not modeled Aug NQC	Market
CRELMN_6_RAMON2				3.89		San Diego	Not modeled Aug NQC	Market
CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	5.00	1	San Diego	Aug NQC	Wind
CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	42.33	G1	None	Aug NQC	Market
CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	42.32	G2	None	Aug NQC	Market
DIVSON_6_NSQF	22172	DIVISION	69	41.54	1	San Diego	Aug NQC	QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	0.24	1	San Diego	Aug NQC	QF/Selfgen
ELCAJN_6_LM6K	23320	EC GEN2	13.8	48.10	1	San Diego, El Cajon		Market
ELCAJN_6_UNITA1	22150	EC GEN1	13.8	45.42	1	San Diego, El Cajon		Market
ENERSJ_2_WIND				24.82		None	Aug NQC	Wind
ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	1	San Diego, Escondido		Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.00	1	San Diego, Escondido		Market
ESCO_6_GLMQF	22332	GOALLINE	69	36.41	1	San Diego, Esco, Escondido	Aug NQC	Net Seller
IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	50.28	1	None	Aug NQC	Market
IVSLRP_2_SOLAR1	23441	DW GEN2 G2	0.36	50.27	1	None	Aug NQC	Market
IVSLRP_2_SOLAR1	23442	DW GEN2 G3	0.36	50.27	1	None	Aug NQC	Market
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	San Diego		Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	San Diego		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	San Diego, Border		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	San Diego, Border		Market
LAROA1_2_UNITA1	20187	LRP-U1	16	165	1	None		Market
LAROA2_2_UNITA1	22997	INTBCT	16	165	1	None		Market
LAROA2_2_UNITA1	22996	INTBST	18	157	1	None		Market
MRGT_6_MEF2	22487	MEF_MR2	13.8	47.90	1	San Diego, Miramar		Market
MRGT_6_MMAREF	22486	MEF_MR1	13.8	48.00	1	San Diego, Miramar		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.36	1	San Diego, Mission	Aug NQC	Market
MSSION_2_QF	22496	MISSION	69	0.73	1	San Diego	Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	34.47	1	San Diego	Aug NQC	QF/Selfgen
OCTILO_5_WIND	23314	OCO GEN G1	0.69	12.21	G1	None	Aug NQC	Wind
OCTILO_5_WIND	23318	OCO GEN G2	0.69	12.21	G2	None	Aug NQC	Wind
OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	San Diego, Pala		Market
OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	2	San Diego, Pala		Market
OTAY_6_LNDFL5	22604	OTAY	69	0.00		San Diego, Border	Not modeled Energy Only	Market
OTAY_6_LNDFL6	22604	OTAY	69	0.00		San Diego, Border	Not modeled Energy Only	Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	San Diego, Border		Market
OTAY_6_UNITB1	22604	OTAY	69	2.90	1	San Diego, Border	Aug NQC	Market
OTAY_7_UNITC1	22604	OTAY	69	2.29	3	San Diego, Border	Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1	San Diego		Market
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1	San Diego		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.83	1	San Diego		Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.39	1	San Diego		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.06	2	San Diego	Aug NQC	QF/Selfgen

PTLOMA_6_NTCQF	22660	POINTLMA	69	18.41	1	San Diego	Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	0.60	1	San Diego	Aug NQC	Net Seller
SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.40	1	San Diego	Aug NQC	QF/Selfgen
TERMEX_2_PL1X3	22981	TDM STG	21	281	1	None		Market
TERMEX_2_PL1X3	22982	TDM CTG2	18	156	1	None		Market
TERMEX_2_PL1X3	22983	TDM CTG3	18	156	1	None		Market
VLCNTR_6_VCSLR1				1.82		San Diego, Pala	Not modeled Aug NQC	Market
VLCNTR_6_VCSLR2				4.02		San Diego, Pala	Not modeled Aug NQC	Market
NA	22916	PFC-AVC	0.6	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
New unit	23162	PIO PICO CT1	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	23163	PIO PICO CT2	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	23164	PIO PICO CT3	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	23287	Q429 G1	0.31	100.00	1	None	No NQC - P max	Market
New unit	23155	c608 G1	0.36	75.00	G1	None	No NQC - P max	Market
New unit	23156	c608_G2	0.36	75.00	G2	None	No NQC - P max	Market
New unit	23100	ECO GEN1 G1	0.69	51.00	G1	None	No NQC - est. data	Wind
New unit	23120	BULLMOOS	13.8	27.00	1	San Diego, Border	No NQC - P max	Market
New unit	23352	Q644G	0.31	20.00	1	None	No NQC - P max	Market
New unit	23487	Q653EDG	0.31	20.00	1	None	No NQC - P max	Market
New unit	22942	BUE GEN 1 G1	0.69	15.40	G1	None	No NQC - est. data	Wind
New unit	22945	BUE GEN 1 G2	0.69	15.40	G2	None	No NQC - est. data	Wind
New unit	22783	EA5 REPOWER1	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	22784	EA5 REPOWER2	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	22786	EA5 REPOWER4	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	22787	EA5 REPOWER5	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	22788	EA5 REPOWER3	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	23105	ECO GEN1 G1	0.69	23.73	G2	None	No NQC - est. data	Wind
New unit	23131	Q183_G1	0.69	0.00	G1	None	Energy Only	Market
New unit	23134	Q183_G2	0.69	0.00	G2	None	Energy Only	Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	San Diego, El Cajon	Retired by 2021	Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	0.00	1	San Diego, Encina	Retired by 2021	Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	San Diego, Encina	Retired by 2021	Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	San Diego, Encina	Retired by 2021	Market
ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	San Diego, Encina	Retired by 2021	Market
ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	San Diego, Encina	Retired by 2021	Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	San Diego, Encina	Retired by 2021	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	San Diego, Mission	Retired by 2021	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	San Diego, Mission	Retired by 2021	Market

KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	San Diego, Mission	Retired by 2021	Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	San Diego, Mission	Retired by 2021	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	San Diego, Miramar	Retired by 2021	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	San Diego, Miramar	Retired by 2021	Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	San Diego, Mission	Retired by 2021	Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	San Diego, Mission	Retired by 2021	Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	San Diego, Mission	Retired by 2021	Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	San Diego, Mission	Retired by 2021	Market

Major new projects modeled:

1. Imperial Valley Phase Shifting Transformers (2x400 MVA)
2. Hassayampa – North Gila #2 500 kV Line (APS)
3. Bay Blvd. Substation Project
4. Sycamore – Penasquitos 230 kV Line
5. Talega Synchronous Condensers (2x225 MVAR)
6. San Luis Rey Synchronous Condensers (2x225 MVAR)
7. San Onofre Synchronous Condenser (225 MVAR)
8. Bypass series capacitors on the ECO-Miguel and Ocotillo-Suncrest 500 kV lines
9. Battery energy storage system projects in the San Diego area (3x10 MW at Escondido and 7.5 MW at El Cajon substations)
10. Reconductor of Mission – Clairmont 69 kV line
11. Reconductor of Mission – Kearny 69 kV line
12. Second Miguel – Bay Blvd. 230 kV line
13. Mesa Heights Loop-In 69 kV Project
14. Second Poway-Pomerado 69 kV line
15. TL632 Granite Loop-In and TL6914 reconfiguration
16. Artesian 230/69 kV Sub and loop-in
17. Pio Pico Power Plant (309 MW)
18. Encina Repower (600 MW)

Critical Contingency Analysis Summary

El Cajon Sub-area

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Murray-Garfield 69 kV line (TL620), which could thermally overload the El Cajon-Los Coches 69 kV (TL631). This limiting contingency establishes a LCR of 7 MW (including 0 MW of QF generation) in 2021 as the minimum generation capacity necessary for reliable load serving capability within this sub-area after the TL632 Granite Loop-In and TL6914 reconfiguration project are completed.

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

Mission Sub-area
The LCR need for the Mission sub-area is eliminated by implementing the ISO Board-approved “The Mesa Heights Loop-In 69 kV Project” with an in-service date of June 2018.

It is recommended to retain at least 52 MW of the Kearny peakers as part of the minimum generation capacity necessary for reliable load serving capability within this sub-area until project is operational.

Effectiveness factors:
All Kearny Peakers have the same effectiveness factor.

Esco Sub-area
The ISO approved Artesian 230 kV substation project and the 2nd Poway-Pomerado 69 kV line will eliminate the local capacity need in this sub-area.

Pala Sub-area
The most critical contingency for the Pala sub-area is the loss of Pendleton – San Luis Rey 69kV line (TL6912) followed by the loss of Lilac - Pala 69kV line (TL6932), which could thermally overload the Monserate – Morro Hill Tap 69 kV line (TL694). This limiting contingency establishes a local capacity need of 13 MW in 2021 (includes 0 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Pala) have the same effectiveness factor.

Border Sub-area

The most critical contingency for the Border sub-area is the loss of Bay Boulevard – Otay 69kV line #1 (TL645) followed by Bay Boulevard Otay – 69 kV line #2 (TL646), which could thermally overload the Imperial Beach – Bay Boulevard 69 kV line (TL647). This limiting contingency establishes a local capacity need of 73 MW in 2021 (includes 2 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Miramar Sub-area

With the implementation of the second Miguel – Bay Blvd. 230 kV line, this sub-area local capacity requirement is eliminated.

It is recommended to retain the Miramar GTs (Cabrillo Power II) until the most limiting contingency is mitigated.

San Diego Sub-area and LA Basin Area Combined:

The critical Category C contingency for the overall LA Basin and San Diego sub-area is the overlapping (N-1-1 or NERC P6) contingency of the Mesa-Redondo 230 kV line, system readjustment, followed by the Mesa-Lighthipe 230 kV line, resulting in thermal limiting constraint, for the combined LA Basin and San Diego sub-area. This contingency could cause loading concerns for the Mesa-Laguna Bell 230 kV line. This limiting contingency establishes an overall total local capacity need for the combined LA Basin/San Diego sub-area of 9412 MW in 2021 as follows: 6898 MW in the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, 432 MW of long-term procurement plan preferred resources, as well as 322 MW of 20-minute demand response) and 2514 MW in the San Diego subarea (includes 103 MW of QF generation, 5 MW of wind, 19 MW of 20-minute demand response and 38 MW of CPUC-approved battery energy storage) as the minimum capacity necessary for reliable load serving capability within these areas.

The critical Category B contingency for the overall LA Basin and San Diego sub-area is the same as the LA Basin/San Diego/Imperial Valley need; the overlapping G-1/N-1 outage (NERC P3 category) of Termoelectrica de Mexicali (TDM) combined cycle plant (593 MW), followed by an N-1 contingency of the Imperial Valley – North Gila 500 kV line. This overlapping contingency could cause thermal overload on the “S” line (El Centro – Imperial Valley 230 kV line) between Imperial Irrigation District (IID) and SDG&E. This limiting contingency establishes a total local capacity need 11054 MW of which 9211 MW is located in the combined LA Basin/San Diego sub-area as follows: 6697 MW in the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, 432 MW of long-term procurement plan preferred resources, as well as 322 MW of 20-minute demand response) and 2514 MW in the San Diego sub-area (includes 103 MW of QF generation, 5 MW of wind, 19 MW of 20-minute demand response and 38 MW of CPUC-approved battery energy storage).

Effectiveness factors:

The following lists the effectiveness factors for resources in the San Diego sub-area in response to thermal loading constraint associated with the overlapping G-1/N-1 contingency.

Resource Locations	Effectiveness Factor (%)
OTAYMGT1 18.0 #1	-17.17
OTAYMGT2 18.0 #1	-17.17
OTAYMST1 16.0 #1	-17.17
PIO PICO C 13.8 #C1	-16.86
PIO PICO C 13.8 #C2	-16.86
PIO PICO C 13.8 #C3	-16.86
CAMERON 69.0 #DG	-16.44

KUMEYAAY	0.7 #1	-16.43
GLENCLIF	69.0 #DG	-16.42
LOVELAND	69.0 #DG	-16.35
DESCANSO	69.0 #DG	-16.26
OY GEN	13.8 #1	-16.19
OTAY	69.0 #3	-16.18
OTAY	69.0 #1	-16.18
EC GEN2	13.8 #1	-16.17
EC GEN1	13.8 #1	-16.15
DIVISION	69.0 #1	-16.14
NOISLMTR	69.0 #1	-16.11
LOSCOCHS	69.0 #DG	-16.08
MURRAY	69.0 #DG	-16.08
SAMPSON	12.5 #1	-16.03
BORDER	69.0 #DG	-16.02
CABRILLO	69.0 #1	-15.94
LRKSPBD1	13.8 #1	-15.92
LRKSPBD2	13.8 #1	-15.92
CALPK_BD	13.8 #1	-15.9
POINTLMA	69.0 #2	-15.88
POINTLMA	69.0 #1	-15.88
CREELMAN	69.0 #DG	-15.84
MESAHGTS	69.0 #1	-15.73
MISSION	69.0 #1	-15.66
SANTYSBL	69.0 #DG	-15.65
CARLTNHS	138.0 #2	-15.63
CARLTNHS	138.0 #1	-15.63
EASTGATE	69.0 #1	-15.3
MEF MR1	13.8 #1	-15.28
GENESEE	69.0 #DG	-15.25
WARNERS	69.0 #DG	-15.22
CHCARITA	138.0 #1	-15.15
MEF MR2	13.8 #1	-15.1
LkHodG1	13.8 #1	-14.35
LkHodG2	13.8 #1	-14.35
VALCNTR	69.0 #DG	-14.06
GOALLINE	69.0 #1	-13.94

BORREGO 12.5 #DG	-13.83
LILAC 69.0 #DG	-13.67
ES GEN 13.8 #1	-13.66
CALPK_ES 13.8 #1	-13.65
PEN_CT1 18.0 #1	-13.62
PEN_CT2 18.0 #1	-13.57
PEN_ST 18.0 #1	-13.56
SANMRCOS 69.0 #1	-13.55
Q189 GEN1 13.8 #1	-13.52
AVOCADO 69.0 #DG	-13.12
PALA 69.0 #DG	-13.1
BR GEN1 0.2 #1	-13.03
PA GEN1 13.8 #1	-12.99
PA GEN2 13.8 #1	-12.99
EA5 REPOWE 13.8 #1	-12.86
EA5 REPOWE 13.8 #1	-12.86
Q137 GEN1 13.8 #1	-12.86
Q137 GEN2 13.8 #1	-12.86
MELROSE 69.0 #DG	-12.72
CAPSTRNO 138.0 #1	-10.24

The following lists the effectiveness factors for resources in the San Diego subarea in response to thermal loading constraint associated with the overlapping N-1-1 contingency for the combined LA Basin-San Diego area.

RESOURCE LOCATIONS	**EFFECTIVENESS FACTORS (%)**
LAGNA NL 138.0 #DG	-7.6
MARGARTA 138.0 #DG	-7.59
CAPSTRNO 138.0 #DG	-7.57
PICO 138.0 #DG	-7.54
AVOCADO 69.0 #DG	-6.82
MELROSE 69.0 #DG	-6.81
MONSRATE 69.0 #DG	-6.76
COASTAL 1 13.8 #1	-6.56
SANMRCOS 69.0 #d1	-6.43
PA GEN1 13.8 #1	-6.4
VALCNTR 69.0 #1	-6.32
ESCNDIDO 69.0 #DG	-6.26
PEN_CT1 18.0 #1	-6.26
ES GEN 13.8 #1	-6.21

GOALLINE 69.0 #1	-6.2
CALPK_ES 13.8 #1	-6.19
LkHodG1 13.8 #1	-6.07
EASTGATE 69.0 #1	-6.02
BERNARDO 69.0 #DG	-6
ARTESN 69.0 #DG	-5.97
MEF MR1 13.8 #1	-5.93
MESAHGTS 69.0 #1	-5.93
CHCARITA 138.0 #1	-5.9
CABRILLO 69.0 #1	-5.89
POINTLMA 69.0 #1	-5.86
CREELMAN 69.0 #DG	-5.8
NOISLMTR 69.0 #1	-5.8
CARLTNHS 138.0 #1	-5.77
DIVISION 69.0 #1	-5.72
EC GEN1 13.8 #1	-5.72
KUMEYAAY 0.7 #1	-5.63
OTAY 69.0 #3	-5.6
OTAY 69.0 #1	-5.6
OY GEN 13.8 #1	-5.58
BORREGO 69.0 #DG	-5.52
SANIGEN 13.8 #D1	-5.42
CIMGEN 13.8 #D1	-5.4
SIMPSON 13.8 #D1	-5.39
CALPK_BD 13.8 #1	-5.3
LRKSPBD1 13.8 #1	-5.3
BULLMOOS 13.8 #1	-5.28
BR GEN1 0.2 #1	-5.12
OTAYMGT1 18.0 #1	-4.95

San Diego Sub-area Requirements:

2021	QF (MW)	Wind (MW)	Battery St. (MW)	Preferred Res. (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	103	5	38	55	2685	2886

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[30]	2514	0	2514
Category C (Multiple) [31]	2514	0	2514

[30] LCR requirement for a single contingency means that there wouldn’t be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

San Diego-Imperial Valley overall:

The critical Category B contingency for the San Diego-Imperial Valley overall is the same as the LA Basin/San Diego/Imperial Valley need; the overlapping G-1/N-1 outage (NERC P3 category) of Termoelectrica de Mexicali (TDM) combined cycle plant (593 MW), followed by an N-1 contingency of the Imperial Valley – North Gila 500 kV line. This overlapping contingency could cause thermal overload on the "S" line (El Centro – Imperial Valley 230 kV line) between Imperial Irrigation District (IID) and SDG&E. This limiting contingency establishes a total local capacity need 11054 MW of which 6697 MW in the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, 432 MW of long-term procurement plan preferred resources, as well as 322 MW of 20-minute demand response) and 4357 MW is located in the San Diego-Imperial Valley area (includes 103 MW of QF generation, 160 MW of wind, 19 MW of 20-minute demand response and 38 MW of CPUC-approved battery energy storage) as the minimum capacity necessary for reliable load serving capability within these areas.

Effectiveness factors:

The effectiveness factors are in addition to the effectiveness factors for generating resources in the San Diego subarea in response to the G-1/N-1 contingency.

Resource Locations	Effectiveness Factor (%)
INTBCT 16.0 #1	-24.87
INTBST 18.0 #1	-24.87
IV GEN2-U1 16.0 #1	-24.82
DU GEN1 G2 0.2 #G2	-24.8
DW GEN1 G2 0.3 #G2	-24.8
DW GEN1 G1 0.3 #G1	-24.79
DU GEN1 G1 0.2 #G1	-24.78
DW GEN3&4 0.3 #2	-24.64
DW GEN3&4 0.3 #1	-24.64

[31] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

DW GEN2 G3	0.4 #1	-24.63
DW GEN2 G1	0.4 #1	-24.55
DW GEN2 G2	0.4 #1	-24.54
OCO GEN G1	0.7 #G1	-21.82
OCO GEN G2	0.7 #G2	-21.82
Q653EDG	0.3 #1	-21.13
ECO GEN1 G	0.7 #G1	-21.05
Q644G	0.3 #1	-20.56

Changes compared to last year's results:

Compared with 2020 the load forecast decreased by 432 MW and the LCR need increased by 1479 MW. The increase is mostly due to transmission constraints not accounted for in last years studies in part driven by cancelation of previously commited transmission upgrades in the Imperial Valley area.

San Diego-Imperial Valley Overall Requirements:

2021	QF (MW)	Wind (MW)	Battery St. (MW)	Preffered Res. (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	103	160	38	55	4484	4840

2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[32]	4357	0	4357
Category C (Multiple)[33]	4357	0	4357

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

[33] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

11. Valley Electric Area

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

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