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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.	Rulemaking 09-10-032 (Filed October 29, 2009)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION SUBMISSION OF 2012 LOCAL CAPACITY TECHNICAL ANALYSIS FINAL REPORT AND STUDY RESULTS

The California Independent System Operator Corporation respectfully submits the ISO's 2012 Local Capacity Technical Analysis Final Report and Study Results (2012 LCR Study) in accordance with the Revised Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge Determining the Scope, Schedule, and Need for Hearing in this Proceeding, issued on February 3, 2011.

Respectfully submitted,

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2012
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 29, 2011

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2012 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2012 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2010. On balance, the assumptions, processes, and criteria used for the 2012 LCT Study mirror those used in the 2007-2011 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2012 LCT study results are provided to the CPUC for consideration in its 2012 resource adequacy requirements program. These results will also be used by the CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as "Local Capacity Requirements" or "LCR") and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Criteria notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2] In this regard, the 2012 LCT Study also provides additional information on sub-area needs and effectiveness factors (where applicable) in order to allow LSEs to engage in more informed procurement.

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

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

Below is a comparison of the 2012 vs. 2011 total LCR:

2012 Local Capacity Requirements

	Qualifying Capacity			2012 LCR Need Based on Category B			2012 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	54	168	222	159	0	**159**	190	22*	**212**
North Coast / North Bay	131	728	859	613	0	**613**	613	0	**613**
Sierra	1277	760	2037	1489	36*	**1525**	1685	289*	**1974**
Stockton	246	259	505	145	0	**145**	389	178*	**567**
Greater Bay	1312	5276	6588	3647	0	**3647**	4278	0	**4278**
Greater Fresno	356	2414	2770	1873	0	**1873**	1899	8*	**1907**
Kern	602	9	611	180	0	**180**	297	28*	**325**
LA Basin	4029	8054	12083	10865	0	**10865**	10865	0	**10865**
Big Creek/ Ventura	1191	4041	5232	3093	0	**3093**	3093	0	**3093**
San Diego	162	2925	3087	2849	0	**2849**	2849	95*	**2944**
Total	**9360**	**24634**	**33994**	**24913**	**36**	**24949**	**26158**	**620**	**26778**

2011 Local Capacity Requirements

	Qualifying Capacity			2011 LCR Need Based on Category B			2011 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	57	166	223	147	0	**147**	188	17*	**205**
North Coast / North Bay	133	728	861	734	0	**734**	734	0	**734**
Sierra	1057	759	1816	1330	313*	**1643**	1510	572*	**2082**
Stockton	267	259	526	374	0	**374**	459	223*	**682**
Greater Bay	1210	5296	6506	4036	0	**4036**	4804	74*	**4878**
Greater Fresno	485	2434	2919	2200	0	**2200**	2444	4*	**2448**
Kern	699	9	708	243	0	**243**	434	13*	**447**
LA Basin	4206	8103	12309	10589	0	**10589**	10589	0	**10589**
Big Creek/ Ventura	1196	4110	5306	2786	0	**2786**	2786	0	**2786**
San Diego	194	3227	3421	3146	0	**3146**	3146	61*	**3207**
Total	**9504**	**25091**	**34595**	**25585**	**313**	**25898**	**27094**	**964**	**28058**

* 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.

Overall, the LCR needs have decreased by more than 1200 MW or almost 5% from 2011 to 2012. The LCR needs have decreased in the following areas: North Coast/North Bay and Greater Bay Area due to downward trend for load; Sierra, Stockton, Fresno, Kern and San Diego due to downward trend for load and new transmission projects. The LCR needs have slightly increased in Humboldt due to load growth; LA Basin and Big Creek /Ventura due to small load growth as well as load allocation change (conform with new CEC forecast). 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 2012 and 2011 LCRs.

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II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the five previous annual LCT Studies, the intent of the 2012 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2012 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2012 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2010.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2012 LCT Study:

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

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

Further details regarding the 2012 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the 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.[3] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the 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., 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

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[3] Pub. Utilities Code § 345

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 mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as 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 LCT Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC standards for the same NERC performance levels. These Performance Levels can be described as follows:

1. 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.

2. Performance Criteria- Category C

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

[4] A Special Protection Scheme is typically proposed as an operational solution that does not require

(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."

3. CAISO Statutory Obligation Regarding Safe Operation

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

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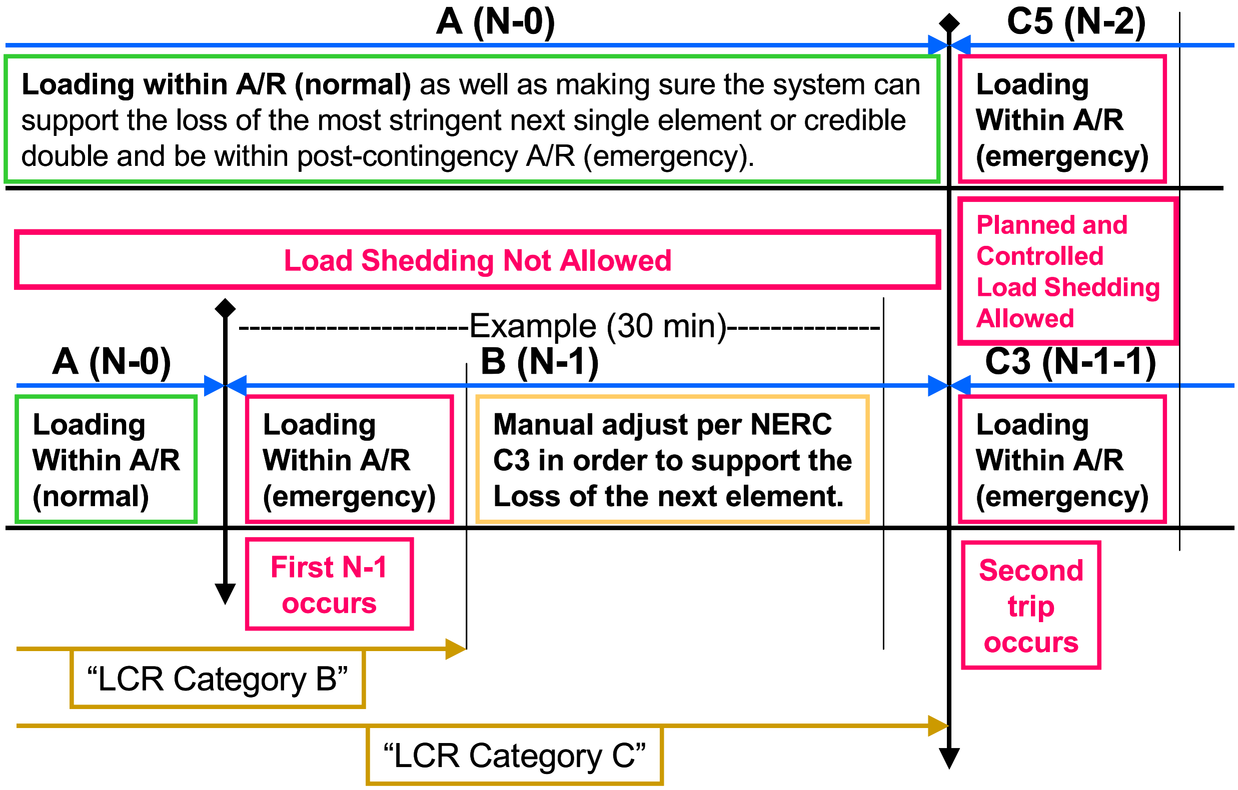
additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.



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

<u>Applicable Rating:</u>

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

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

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

<u>Short-term emergency ratings</u>, 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.

This is one of the most controversial aspects of the interpretation of the existing NERC criteria because the NERC 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.

<u>Time allowed for manual readjustment:</u>

This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes, based on existing CAISO Planning Standards.

This is a somewhat controversial aspect of the interpretation of existing criteria. This item is very specific in the CAISO Planning Standards. However, some will argue that 30 minutes only allows generation re-dispatch and automated switching where remote control is possible. If remote capability does not exist, a person must be dispatched in the field to do switching and 30 minutes may not allow sufficient time. If approved, an exemption from the existing time requirements may be given for small local areas with very limited exposure and impact, clearly described in operating procedures, and only until remote controlled switching equipment can be installed.

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.[5]

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:

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

Table 4: Criteria Comparison

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

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.
2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.
4 Evaluate for risks and consequence, per NERC standards.

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

1. Power Flow Assessment:

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

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

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

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

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

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

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

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

2. **Post Transient Load Flow Assessment:**

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

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

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

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

a. PTO Loads in Base Case

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

i. Determination of division loads

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

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed must be allocated to those buses. The allocation process is different depending on the load types. For the most part, each PTO classifies its loads

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

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 LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 17.0. 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. An 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. Local Capacity Requirement Study Results

A. Summary of Study Results

LCR is defined as the amount of generating 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: 2012 Local Capacity Needs vs. Peak Load and Local Area Generation

	2012 Total LCR (MW)	Peak Load (1 in10) (MW)	2012 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2012 LCR as % of Total Area Generation
Humboldt	212	210	101%	222	95%**
North Coast/North Bay	613	1420	43%	859	71%
Sierra	1974	1816	109%	2037	97%**
Stockton	567	1086	52%	505	112%**
Greater Bay	4278	9954	43%	6588	65%
Greater Fresno	1907	3120	61%	2770	69%**
Kern	325	1110	29%	611	53%**
LA Basin	10865	19931	55%	12083	90%
Big Creek/Ventura	3093	4693	66%	5232	59%
San Diego	2944	4844	61%	3087	95%**
Total	**26,778**	**48184***	**56%***	**33,994**	**79%**

Table 6: 2011 Local Capacity Needs vs. Peak Load and Local Area Generation

	2011 Total LCR (MW)	Peak Load (1 in10) (MW)	2011 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2011 LCR as % of Total Area Generation
Humboldt	205	206	100%	223	92%**
North Coast/North Bay	734	1574	47%	861	85%
Sierra	2082	1977	105%	1816	115%**
Stockton	682	1163	59%	526	130%**
Greater Bay	4878	10322	47%	6506	75%**
Greater Fresno	2448	3306	74%	2919	84%**

Kern	447	1387	32%	708	63%**
LA Basin	10589	20223	52%	12309	86%
Big Creek/Ventura	2786	4648	60%	5306	53%
San Diego	3207	5036	64%	3421	94%**
Total	**28,058**	**49842***	**56%***	**34,595**	**81%**

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

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

Tables 5 and 6 shows how much of the Local Capacity Area load is dependent on local generation and how much local generation 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 generation 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 generation.

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

http://www.caiso.com/1796/179688b22c970.html

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 6/1/2012 have been included in this 2012 LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

The first column, "Qualifying Capacity," reflects two sets of generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (state, federal, QFs, wind and nuclear units). The second set is "market" generation. The second column, "2012 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, "2012 LCR Requirement

Based on Category C with Operating Procedure", sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

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

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	27442	4116	-8849	-3750	**18959**
NP26=NP15+ZP26	21174	3176	-4724	-902	**16724**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2012.

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

Allocated Imports are the actual 2011 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2012 because there are no additional import transmission additions to the grid between now and summer of 2012.

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

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

[8] "Loop flow" is a phenomenon common to large electric power systems like the Western Electricity Coordinating Council. Power is scheduled to flow point-to-point on a Day-ahead and Hour-ahead basis through the CAISO. However, electric grid physics prevails and the actual power flow in real-time will

MW (South-to-North).

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

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

Changes compared to last year's results:

- The load forecast went down in Southern California by about 800 MW and down in Northern California by about 900 MW.
- The Import Allocations went up in Southern California by about 300 MW and down in Northern California by about 150 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2011. If there are any changes, they will be heavily influenced by the pre-existing "grandfathered contracts" and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

C. Summary of Results by Local Area

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

differ from the pre-arranged scheduled flows. Loop flow is real, physical energy and it uses part of the available transfer capability on a path. If not accommodated, loop flow will cause overloading of lines, which can jeopardize the security and reliability of the grid.

1. Humboldt Area

Area Definition

The transmission tie lines into the area include:

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

The substations that delineate the Humboldt Area are:

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

Total 2012 busload within the defined area: 200 MW with 10 MW of losses resulting in total load + losses of 210 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
BRDGVL_7_BAKER				0.00		None	Not modeled Aug NQC	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.49	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
FTSWRD_7_QFUNTS				0.40		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	2	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.77	4	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	17.00	5	Humboldt 60 kV		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.99	6	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	8	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	9	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	10	Humboldt 60 kV		Market

HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.42	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.41	2	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.45	3	Humboldt 60 kV	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.00		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	7	Humboldt 60 kV	No NQC - Pmax	Market
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	Humboldt 60 kV	Energy Only	Market

Major new projects modeled:

1. Humboldt Bay Repower
2. Humboldt Reactive Support
3. Blue Lake generation project (energy only 0 MW NQC)

Critical Contingency Analysis Summary

Humboldt 60 kV Sub-area:

The most critical contingency for the Humboldt 60 kV Sub-area area is the outage of the Humboldt 115/60 Transformer and one of the gen tie-line connecting the new Humboldt Bay units (on 60 kV side). The area limitation is the overload on the parallel Humboldt 115/60 kV Transformer. This contingency establishes a LCR of 177 MW in 2012 (includes 54 MW of QF/Selfgen generation as well as 22 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the outage of the Humboldt 115/60 kV Transformer. The limitation is thermal overload on the parallel Humboldt 115/60 kV Transformer. This limiting contingency establishes a LCR of 129 MW in 2012 (includes 54 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt 60 kV Sub-area area with at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	73
31158	LP SAMOA	1	73
31182	HUMB_G3	10	68
31182	HUMB_G3	9	68
31182	HUMB_G3	8	68
31181	HUMB_G2	7	68
31181	HUMB_G2	6	68
31181	HUMB_G2	5	68
31180	HUMB_G1	4	-14
31180	HUMB_G1	3	-14
31180	HUMB_G1	2	-14
31180	HUMB_G1	1	-14
31152	PAC.LUMB	1	40
31152	PAC.LUMB	2	40
31153	PAC.LUMB	3	40

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV Line overlapping with an outage of one of the tie-line connecting the new Humboldt Bay units on the 115 kV side. The area limitation is the overload on the Humboldt – Trinity 115 kV Line. This contingency establishes a LCR of 190 MW in 2012 (includes 54 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

For the single contingency, the most critical one is an outage of the Bridgeville-Cottonwood 115 kV Line when one of the Humboldt Bay Power Plant units connected to the 115 kV bus is out of service. The limitation is the overload on the Humboldt – Trinity 115 kV Line. This limiting contingency establishes a LCR of 159 MW in 2012 (includes 54 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt Overall system with at least 5% effective to the above-mentioned constraint

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	58
31158	LP SAMOA	1	58
31182	HUMB_G3	10	57
31182	HUMB_G3	9	57
31182	HUMB_G3	8	57
31181	HUMB_G2	7	57
31181	HUMB_G2	6	57
31181	HUMB_G2	5	57
31180	HUMB_G1	4	59
31180	HUMB_G1	3	59
31180	HUMB_G1	2	59
31180	HUMB_G1	1	59
31152	PAC.LUMB	1	52
31152	PAC.LUMB	2	52
31153	PAC.LUMB	3	52

Changes compared to last year's results:

The Humboldt Repowering Project (HBPP) was modeled an on-line in both 2011 and 2012 LCR studies. Two new transmission projects, the Maple Creek and Garberville Reactive support projects were modeled in 2011 studies, but not in 2012 because these projects were delayed past the 2012 peak. The overall load is expected to increase by 4 MW from 2011 to 2012 the overall LCR need has increased by 6 MW and the LCR resource need increased by 2 MW. The limiting outage and limiting facilities were the same as in the 2011 LCR.

Humboldt Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	54	0	168	222

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	159	0	159
Category C (Multiple)[10]	190	22	212

2. North Coast / North Bay Area

<u>Area Definition</u>

The North Coast/North Bay Area is composed of three sub-areas and the generation requirements within them. The transmission tie facilities coming into the North Coast/North Bay area are:

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

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

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

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[9] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[10] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

6) Lakeville is in, Sobrante is out
7) Ignacio is in, Sobrante and Crocket are out

Total 2012 busload within the defined area: 1386 MW with 34 MW of losses resulting in total load + losses of 1420 MW.

Total units and qualifying capacity available in this area are shown in the following table:

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
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.05		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	60.00	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_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	47.00	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	40.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	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				1.68		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HIWAY_7_ACANYN				1.04		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	0.81	1	Eagle Rock, Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.90	1	Fulton, Lakeville	Aug NQC	QF/Selfgen

MONTPH_7_UNITS	32700	MONTICLO	9.1	3.90	2	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.93	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NAPA_2_UNIT				0.02		Lakeville	Not modeled 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	0.00	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				0.02		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	5.15	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	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

Major new projects modeled: None

<u>Critical Contingency Analysis Summary</u>

Eagle Rock Sub-area

The most critical overlapping contingency is the outage of the Cortina-Mendocino 115 kV line overlapping with an outage of the Fulton-Lakeville 230 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 207 MW in 2012 (includes 1 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 the outage of 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 LCR of 166 MW in 2012 (includes 1 MW of QF/MUNI generation).

Effectiveness factors:

All the units within the Eagle-Rock sub-area have the same effectiveness to the described constraints. Units outside this area are not effective.

Fulton Sub-area

The most critical overlapping contingency is the outage of the Lakeville-Fulton 230 kV line #1 and the Fulton-Ignacio 230 kV line #1. The sub-area area limitation is thermal overloading of Santa Rosa-Corona 115 kV line #1. This limiting contingency establishes a LCR of 293 MW (includes 16 MW of QF and 54 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31404	WEST FOR	2	73
31402	BEAR CAN	1	73
31402	BEAR CAN	2	73
31404	WEST FOR	1	73
31414	GEYSER12	1	73
31418	GEYSER14	1	73
31420	GEYSER16	1	73
31422	GEYSER17	1	73
38110	NCPA2GY1	1	73
38112	NCPA2GY2	1	73
31421	BOTTLERK	1	72
31406	GEYSR5-6	1	38
31406	GEYSR5-6	2	38
31408	GEYSER78	1	38
31408	GEYSER78	2	38
31412	GEYSER11	1	38
31435	GEO.ENGY	1	38
31435	GEO.ENGY	2	38

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Tulucay 230 kV line with DEC power plant out of service. The sub-area limitation is thermal overloading of the Vaca Dixon-Lakeville 230 kV. This limiting contingency establishes a LCR of 613 MW (includes 18 MW of QF and 113 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

The following table has units within the North Coast/North Bay area at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	37
31430	SMUDGEO1	1	37
31400	SANTA FE	1	37
31416	GEYSER13	1	37
31424	GEYSER18	1	37
31426	GEYSER20	1	37
38106	NCPA1GY1	1	37
38108	NCPA1GY2	1	37
31421	BOTTLERK	1	35
31404	WEST FOR	2	35
31402	BEAR CAN	1	35
31402	BEAR CAN	2	35
31404	WEST FOR	1	35
31414	GEYSER12	1	35
31418	GEYSER14	1	35
31420	GEYSER16	1	35
31422	GEYSER17	1	35
38110	NCPA2GY1	1	35
38112	NCPA2GY2	1	35
31406	GEYSR5-6	1	19
31406	GEYSR5-6	2	19
31408	GEYSER78	1	19
31408	GEYSER78	2	19
31412	GEYSER11	1	19
31435	GEO.ENGY	1	19
31435	GEO.ENGY	2	19

Changes compared to last year's results:

Overall the load forecast went down by 154 MW for 2012 compared with last year load forecast for 2011 and the LCR need went down by 121 MW.

North Coast/North Bay Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	18	113	728	859

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	613	0	613
Category C (Multiple)[12]	613	0	613

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 STIG-Eight Mile Road 230 kV line
12) Gold Hill-Lake 230 kV line

[11] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[12] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

The substations that delineate the Sierra Area are:

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

Total 2012 busload within the defined area: 1713 MW with 103 MW of losses resulting in total load + losses of 1816 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
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	9.1	21.64	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.63		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_UNIT	32480	BOWMAN	9.1	2.41	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				1.06		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

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 Mountain	Aug NQC	MUNI
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_7_MNMETH				2.11		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	3.78	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	9.1	0.36	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	39.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
GOLDHL_1_QF				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	6.19	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	31.65	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	35.29	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	6.71	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HIGGNS_7_QFUNTS				0.04		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	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	2.98	1	Colgate, South of Table	Aug NQC	Market

						Mountain		
NAROW2_2_UNIT	32468	NARROWS2	9.1	20.52	1	Colgate, 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	9.1	4.71	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	7.97	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	7.97	2	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	2.30	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	0.72		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	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				0.94		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	5.47	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market

SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	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	10.55	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	MUNI	
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	19.12	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	55.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.20		Colgate, South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	9.84	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	0.22	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	9.1	26.26	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain	Market	
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	4.60	1	Colgate, South of Table Mountain	No NQC - hist. data	MUNI
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	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
New unit	38123	Q267CT1	18	166.00	1	South of Rio Oso, South of Palermo, South of Table Mountain	No NQC - Pmax	MUNI
New unit	38124	Q267ST1	18	114.00	1	South of Rio Oso, South of Palermo, South of Table Mountain	No NQC - Pmax	MUNI

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. Atlantic-Lincoln 115 kV Transmission Upgrade
3. Gold Hill – Horseshoe 115 kV line Reconductoring
4. Palermo-Rio Oso 115 kV Reconductoring
5. Lodi Energy Center

<u>Critical Contingency Analysis Summary</u>

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV and Table Mountain-Palermo double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limiting contingency establishes in 2012 a LCR of 1399 MW (includes 176 MW of QF and 1101 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The units required for the South of Palermo sub-area satisfy the category B requirement for this sub-area.

Effectiveness factors:

The following table has all units in Sierra area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	8
31794	WOODLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31888	OROVLLE	1	6
31890	PO POWER	2	6
31890	PO POWER	1	6
31834	KELLYRDG	1	6
32452	COLGATE2	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5

32451	FREC	1	5
32490	GRNLEAF1	2	4
32490	GRNLEAF1	1	4
32496	YCEC	1	3
32494	YUBA CTY	1	3
32492	GRNLEAF2	1	3
32156	WOODLAND	1	3
31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2
31792	POE 2	1	2
31790	POE 1	1	2
31786	ROCK CK1	1	2
31784	BELDEN	1	2
32166	UC DAVIS	1	2
32500	ULTR RCK	1	2
32498	SPILINCF	1	2
32162	RIV.DLTA	1	2
32510	CHILIBAR	1	2
32514	ELDRADO2	1	2
32513	ELDRADO1	1	2
32478	HALSEY F	1	2
32458	RALSTON	1	2
32456	MIDLFORK	1	2
32456	MIDLFORK	2	2
38114	Stig CC	1	2
32460	NEWCSTLE	1	2
32512	WISE	1	2
32486	HELLHOLE	1	2
32508	FRNCH MD	1	2
32502	DTCHFLT2	1	2
32462	CHI.PARK	1	2
32464	DTCHFLT1	1	1
32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
32480	BOWMAN	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1

32472	SPAULDG	3	1
38123	Q267CT1	1	1
38124	Q267ST1	1	1

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV transmission upgrade project. If this project is delayed all units within this area (Narrows #1 & #2 and Camp Far West) are needed.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Green Leaf II Cogen unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 103 MW (includes 62 MW of QF generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) have the same effectiveness factor.

Bogue Sub-area

No requirement due to the Palermo-Rio Oso Reconductoring Project. If this project is delayed all units within this area (Greenleaf #1 units 1&2 and Feather River EC) are needed.

South of Palermo Sub-area

The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a LCR of 1626 MW (includes 694 MW of QF and Muni generation as well as 268 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo- East Nicolaus 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This contingency establishes in 2012 a LCR of 1394 MW (includes 694 MW of QF and Muni generation as well as 36 MW of deficiency)

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

Placerville Sub-area
The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 81 MW (includes 0 MW of QF and Muni generation as well as 57 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:
All units within this area (El Dorado units 1&2 and Chili Bar) are needed therefore no effectiveness factor is required.

Placer Sub-area
The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a LCR of 75 MW (includes 0 MW of QF and Muni generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #2 115 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 44 MW (includes 0 MW of QF and Muni generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2012 a LCR of 625 MW (includes 374 MW of QF and Muni generation) 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 #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2012 a LCR of 254 MW (includes 374 MW of QF and Muni generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32156	WOODLAND	1	22
32490	GRNLEAF1	1	22
32490	GRNLEAF1	2	22
32451	FREC	1	21
32166	UC DAVIS	1	18
32498	SPILINCF	1	15
32502	DTCHFLT2	1	15
32494	YUBA CTY	1	14
32496	YCEC	1	14
32492	GRNLEAF2	1	13
32454	DRUM 5	1	13
32476	ROLLINSF	1	13
32474	DEER CRK	1	13
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	13

32506	DRUM 3-4	2	13
32484	OXBOW F	1	13
32472	SPAULDG	3	12
32472	SPAULDG	1	12
32472	SPAULDG	2	12
32488	HAYPRES+	1	12
32480	BOWMAN	1	12
32488	HAYPRES+	2	12
32464	DTCHFLT1	1	11
32162	RIV.DLTA	1	11
32462	CHI.PARK	1	9
32500	ULTR RCK	1	6
31862	DEADWOOD	1	5
31814	FORBSTWN	1	5
31832	SLY.CR.	1	5
31794	WOODLEAF	1	5
32478	HALSEY F	1	2
31888	OROVLLE	1	2
32512	WISE	1	2
31834	KELLYRDG	1	2
31890	PO POWER	1	2
31890	PO POWER	2	2
32460	NEWCSTLE	1	1

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Lincoln 115 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 630 MW (includes 622 MW of QF and Muni) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 453 MW (includes 622 MW of QF and Muni generation) in 2012.

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

Changes compared to last year's results:

Overall the Sierra Area load forecast went down by 161 MW. Along with a few new transmission projects there is also one new power plant (Lodi Energy Center) modeled within the Sierra LCR area. As a result, the existing generation capacity needed is increased by 175 MW. As such, the magnitude of the deficiency has significantly reduced because of this resource addition.

Sierra Overall Requirements:

2012	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	176	1101	760	2037

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1489	36	1525
Category C (Multiple)[14]	1685	289	1974

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

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

4. Stockton Area

Area Definition

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

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

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

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

The substations that delineate the Lockeford Sub-area are:

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

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

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

The substations that delineate the Weber Sub-area are:

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

Total 2011 busload within the defined area: 1067 MW with 19 MW of losses resulting in total load + losses of 1086 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	Aug NQC	MUNI
COGNAT_1_UNIT	33818	COG.NTNL	12	25.46	1	Weber	Aug NQC	QF/Selfgen
CURIS_1_QF				0.49		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota	Aug NQC	MUNI
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford		MUNI
PHOENX_1_UNIT				1.46		Tesla-Bellota	Not modeled Aug NQC	Market
SCHLTE_1_UNITA1	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_UNITA2	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	10.67	1	Tesla-Bellota	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	2.28	1	Tesla-Bellota	Aug NQC	QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.02	1	Tesla-Bellota	Aug NQC	Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota	Aug NQC	Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	15.72	1	Tesla-Bellota	Aug NQC	QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	42.74	1	Tesla-Bellota	Aug NQC	QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	13.34	1	Tesla-Bellota	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.39		Tesla-Bellota	Not modeled Aug	QF/Selfgen

							NQC	
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	1	Tesla-Bellota	No NQC - hist. data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	2	Tesla-Bellota	No NQC - hist. data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	3	Tesla-Bellota	No NQC - hist. data	MUNI
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

Major new projects modeled:

1. Tesla 115 kV Capacity Increase
2. Tesla-Schulte, Lammer-Kasson & Schulte-Lammers Tower Raise Project
3. Weber-Stockton “A” #1 & #2 60 kV Reconductoring

Critical Contingency Analysis Summary

Stockton overall

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 451 MW (includes 76 MW of QF and 118 MW of Muni generation as well as 114 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Kasson-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 401 MW (includes 76 MW of QF and 118 MW of Muni generation as well as 114 MW of deficiency) in 2012.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Kasson-Manteca 115 kV. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This limiting contingency establishes a 2012 local capacity need of 337 MW (includes 76 MW of QF and 118 MW of Muni generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the Stanislaus unit #1. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This single contingency establishes a local capacity need of 123 MW (includes 194 MW of QF and Muni generation) in 2012.

Effectiveness factors:

All units within this sub-area are needed for the most limiting contingencies therefore no effectiveness factor is required.

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2012 local capacity need of 55 MW (including 2 MW of QF and 23 MW of Muni generation as well as 30 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this 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 the Weber 230/60 kV Transformer #1 with the Cogeneration National out of service. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 61 MW (including 27 MW of QF and Muni generation as well as a deficiency of 34 MW) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency for this sub-area is the loss of Weber 230/60 kV Transformer #1. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 22 MW (including 27 MW of QF and Muni generation) in 2012.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the Stockton area load forecast went down by 77 MW. There are also two new transmission upgrades (Tesla-Schulte, Lammer-Kasson & Schulte-Lammers Tower Raise Project & Weber-Stockton "A" #1 & #2 60 kV Reconductoring) modeled in the Stockton LCR area this year. As a result, the overall requirement for the Stockton area went down by 126 MW.

Stockton Overall Requirements:

2012	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	105	141	259	505

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	145	0	145
Category C (Multiple)[16]	389	178	567

5. Greater Bay Area

<u>Area Definition</u>

The transmission tie lines into the Greater Bay Area are:

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

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

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Birds Landing SW Sta 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
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 Crocket and Sobrante are in
3) Parkway is out Moraga is in
4) Bahia is out Moraga is in
5) Lambie SW Sta is in Vaca Dixon is out
6) Peabody is out Birds Landing SW Sta is in
7) Tesla and USWP Ralph are out Kelso is in
8) Tesla and Altmont Midway are out Delta Switching Yard is in
9) Tesla and Tres Vaqueros are out Pittsburg is in
10) Tesla and Flowind are out Pittsburg is in
11) Tesla is out Newark is in
12) Tesla is out Newark and Patterson Pass are in
13) Tesla is out Ravenswood is in
14) Tesla is out Metcalf is in
15) 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 2012 bus load within the defined area is 9493 MW with 197 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 9954 MW. This corresponds to about 9355 MW of load per CEC forecast since there are about 600 MW of loads behind the meter modeled in the base cases.

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	38820	DELTA A	13.2	9.00	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	9.00	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	22.00	3	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	9	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	11	Contra Costa	Pumps	MUNI
BLHVN_7_MENLOP				1.16		None	Not modeled Aug NQC	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	34.53	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	37.11	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILO	34.5	36.03	2	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	22.35	1	San Jose	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.04	1	None	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.04	2	None	Aug NQC	QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen

COCOPP_7_UNIT 6	33116	C.COS 6	18	337.00	1	Contra Costa		Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	337.00	1	Contra Costa		Market
CONTAN_1_UNIT	36856	CCA100	13.8	25.80	1	San Jose	Aug NQC	QF/Selfgen
CROKET_7_UNIT	32900	CRCKTCOG	18	173.57	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose		MUNI
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		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
FLOWD2_2_UNIT 1	35318	FLOWDPTR	9.11	3.32	1	Contra Costa	Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	189.27	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	185.36	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	185.36	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas	Aug NQC	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	24.96	1	None	Aug NQC	QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	18.01	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.00	1	Pittsburg	Aug NQC	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	16.94	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	16.77	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	17.72	1	Pittsburg	Aug NQC	QF/Selfgen
HICKS_7_GUADLP				2.07		None	Not modeled Aug NQC	QF/Selfgen
KIRKER_7_KELCYN	32951	KIRKER	115	3.21		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	Aug NQC	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Aug NQC	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	2.05	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
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
METCLF_1_QF				0.08		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	None	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.09		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.01		San Jose	Not modeled Aug NQC	QF/Selfgen
MNTAGU_7_NEWBYI				3.56		None	Not modeled Aug NQC	QF/Selfgen
NEWARK_1_QF				0.02		None	Not modeled Aug NQC	QF/Selfgen
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
OAK L_7_EBMUD				0.48		Oakland	Not modeled Aug NQC	MUNI
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	312.00	1	Pittsburg		Market

PITTSP_7_UNIT 6	33106	PTSB 6	18	317.00	1	Pittsburg		Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	682.00	1	Pittsburg		Market
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.31	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.63	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.03	1	None	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	2	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	3	Pittsburg	Aug NQC	QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	14.68	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	3	Pittsburg	Aug NQC	QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	22.96	1	None	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	12.79	1	Contra Costa	Aug NQC	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	21.68	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.64	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.64	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	2.27	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	2.62	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	4.70	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	5.00	1	San Jose	No NQC - hist. data	QF/Selfgen
BRDSLD_2_MTZUMA	32171	HIGHWND3	34.5	10.00	1	Contra Costa	No NQC - est. data	Wind
New Unit	32179	T222	0.69	19.5	1	Contra Costa	No NQC - est. data	Wind
New Unit	32186	P0609	34.5	40	1	Contra Costa	No NQC - est. data	Wind

New Unit	32188	P0611G	34.5	7.5	1	Contra Costa	No NQC - est. data	Wind
New Unit	32190	Q039	0.58	24.9	1	Contra Costa	No NQC - est. data	Wind
New Unit	35304	Q045CTG1	15	0.00	1	None	Delayed	Market
New Unit	35305	Q045CTG2	15	0.00	1	None	Delayed	Market
New Unit	35306	Q067STG1	15	0.00	1	None	Delayed	Market
POTRPP_7_UNIT 3	33252	POTRERO3	20	0.00	1	None	Retired	Market
POTRPP_7_UNIT 4	33253	POTRERO4	13.8	0.00	1	None	Retired	Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	0.00	1	None	Retired	Market
POTRPP_7_UNIT 6	33255	POTRERO6	13.8	0.00	1	None	Retired	Market

Major new projects modeled:

1. AHW #1 & #2 115kV Re-Cabling
2. New TransBay DC cable
3. New Oakland C-X #3 115kV Cable
4. San Mateo – Bay Meadows 115kV #1 & #2 Line Reconductoring
5. Four Wind farms connected to Birds Landing (~ 340 MW P max)
6. Retirement of Potrero #3, #4, #5 and #6

<u>Critical Contingency Analysis Summary</u>

San Francisco Sub-area

LCR need has been eliminated due to the Trans Bay DC cable and re-cabling of the AHW #1 and # 2 115 kV.

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the D-L 115 kV lines. This limiting contingency establishes a LCR of 55 MW in 2012 (includes 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

This Oakland requirement does not include the need for Pittsburg/Oakland sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-Llagas 115 kV line as well as voltage drop (5%) at the Morgan Hill substation. As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 100 MW in 2012 (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 area have the same effectiveness factor. Units outside of this area are not effective.

San Jose Sub-area

The most critical contingency is an outage of Metcalf-El Patio #1 or #2 115 kV line followed by Metcalf-Evergreen #1 115 kV line. The area limitation is thermal overloading of the Evergreen – San Jose B 115 kV line. This limiting contingency establishes a LCR of 352 MW in 2012 (includes 53 MW of QF and 202 MW of Muni 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 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	20
36856	CCCA100	1	6

36854	Cogen	1	6
36854	Cogen	2	6
36863	DVRaGT1	1	6
36864	DVRbGT2	1	6
36865	DVRaST3	1	6
35860	OLS-AGNE	1	5
36858	Gia100	1	5
36859	Gia200	2	5
35854	LECEFGT1	1	5
35855	LECEFGT2	2	5
35856	LECEFGT3	3	5
35857	LECEFGT4	4	5

Pittsburg and Oakland Sub-area Combined

The most critical contingency is an outage of the Moraga #3 230/115 kV transformer combined with the loss of Delta Energy Center. The sub-area area limitation is thermal overloading of Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 3008 MW in 2012 (including 448 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 Moraga #3 230/115 kV transformer. The sub-area area limitation is thermal overloading of the Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2729 MW in 2012 (including 448 MW of QF/Muni generation).

Effectiveness factors:

Please see Bay Area overall.

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with the Gateway off line. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 875 MW in 2012 (includes 52 MW of QF and 259 MW of Wind generation and 264 MW of MUNI pumps) 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 to the above-mentioned constraint.

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

As the aggregate sub pocket LCR is adequate to cover the overall Bay area contingency,

- Sum of the sub pockets for Category B is binding at 3647 MW
- Sum of the sub pockets for Category C is binding at 4278 MW

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors (posted under M-403Z) at: http://www.caiso.com/237e/237eda4b5070.pdf

Changes compared to last year's results:

Overall the load forecast went down by 368 MW. As a result, LCR decreases by 426 MW. Due to the significantly increased Delta pump load (from 157 MW to 264 MW), a new pocket is modeled this year to calculate the LCR for the effective generation to mitigate a contingency in this sub-pocket. Furthermore the sum of the sub pocket LCR needs is adequate to cover the overall Bay area contingency. Therefore, no additional LCR is needed for the overall Bay area.

Bay Area Overall Requirements:

2012	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	261	532	519	5276	6588

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	3647	0	3647
Category C (Multiple)[18]	4278	0	4278

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

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

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

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

The substations that delineate the Greater Fresno area are:

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

2012 total busload within the defined area is 3014 MW with 105 MW of losses resulting in a total (load plus losses) of 3120 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
AGRICO_6_PL3N5	34608	AGRICO	13.8	16.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00	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	30805	BORDEN	230	0.68		Wilson	Not modeled Aug NQC	QF/Selfgen
BULLRD_7_SAGNES				0.00		Wilson	Not modeled Aug NQC	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	7.69	1	Wilson Aug	NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.62	2	Wilson Aug	NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	5.76	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	35.57	1	Wilson Aug	NQC	QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	1.20		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA				0.71		Wilson	Not modeled Aug NQC	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson Aug	NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson Aug	NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	5.66	1	Wilson Aug	NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson Aug	NQC	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	5.29	2	Wilson Aug	NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	2.83	3	Wilson Aug	NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.75	4	Wilson Aug	NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	41.50	1	Wilson		Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_6_UNIT	34650	GWF-PWR.	9.11	24.03	1	Wilson, Henrietta	Aug NQC	QF/Selfgen
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Aug NQC	Market

HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson Aug	NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	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, Henrietta		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson, Henrietta		Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	1.63	1	Wilson Aug	NQC	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	3.68	1	Wilson Aug	NQC	QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50	2	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34344	KERCKHOF	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	23.31	1	Wilson, Herndon	Aug NQC	QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	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				0.72		Wilson, Herndon	Not modeled Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	4.57	1	Wilson Aug	NQC	MUNI
MENBIO_6_UNIT	34334	BIO PWR	9.11	21.61	1	Wilson Aug	NQC	QF/Selfgen
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.03	1	Wilson Aug	NQC	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.12	1	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.12	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.13	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	40.00	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	42.78	1	Wilson		Market
SGREGY_6_SANGER	34646	SANGERCO	9.11	26.96	1	Wilson Aug	NQC	QF/Selfgen
STOREY_7_MDRCHW				0.88		Wilson	Not modeled Aug NQC	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	17.30	1	Wilson, Herndon	Aug NQC	QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson Aug	NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson Aug	NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson Aug	NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson Aug	NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson Aug	NQC	Market

WRGHTP_7_AMENGY				0.53		Wilson	Not modeled Aug NQC	QF/Selfgen
NA	34485	FRESNOWW	12.5	9.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	2	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	1.00	3	Wilson	No NQC - hist. data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - hist. data	MUNI
MENBIO_6_RENEW1	34339	CALRENEW	12.5	0.00	1	Wilson Energ	y Only	Market
New Unit	34696	Q478	21	0.00	1	Wilson, Herndon	Energy Only	Market
New Unit	34603	JQBSWLT	12.5	0.00	ST	Wilson Energ	y Only	Market

Major new projects modeled:

1. Herndon 230 to 115 kV Transformer bank # 3

Critical Contingency Analysis Summary

Wilson Sub-area

The Wilson sub-area largely defines the Fresno area import constraints. The main constrained spot is located at Warnerville-Wilson-Gregg 230 kV transmission corridor. Other constrained spots are located at the Gates-McCall, Gates-Gregg, Panoche-McCall and Panoche-Gregg 230 kV transmission corridors.

The most critical contingency is the loss of the Melones - Wilson 230 kV line overlapped with one of the Helms units out of service. This contingency would thermally overload the Warnerville - Wilson 230 kV line (most stringent) and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a LCR of 1873 MW in 2012 (includes 189 MW of QF and 167 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within Fresno that are at least 5% effective to the constraint on the Warnerville – Wilson 230 kV line.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34332	JRWCOGEN	1	40%
34330	ELNIDO	1	37%
34322	MERCEDFL	1	35%

34320	MCSWAIN	1	34%
34306	EXCHQUER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCOGN	1	32%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34631	SJ2GEN	1	28%
34633	SJ3GEN	1	27%
34636	FRIANTDM	2	27%
34636	FRIANTDM	3	27%
34636	FRIANTDM	4	27%
34600	HELMS 1	1	27%
34602	HELMS 2	1	27%
34604	HELMS 3	1	27%
34308	KERCKHOF	1	26%
34344	KERCKHOF	1	26%
34344	KERCKHOF	2	26%
34344	KERCKHOF	3	26%
34485	FRESNOWW	1	24%
34648	DINUBA E	1	22%
34179	MADERA_G	1	22%
34616	KINGSRIV	1	22%
34624	BALCH 1	1	21%
34671	KRCDPCT1	1	21%
34672	KRCDPCT2	1	21%
34640	ULTR.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%
34696	Q478	1	18%
34610	HAAS	1	18%
34610	HAAS	1	18%
34614	BLCH 2-3	1	18%
34612	BLCH 2-2	1	17%
38720	PINE FLT	1	17%
38720	PINE FLT	2	17%
38720	PINE FLT	3	17%
34431	GWF_HEP1	1	17%
34433	GWF_HEP2	1	17%
34334	BIO PWR	1	14%
34608	AGRICO	2	14%
34608	AGRICO	3	14%
34608	AGRICO	4	14%
34539	GWF_GT1	1	14%
34541	GWF_GT2	1	14%
34650	GWF-PWR.	1	13%
34186	DG_PAN1	1	11%
34142	WHD_PAN2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%

34553	WHD_GAT2	1	9%
34654	COLNGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Herndon Sub-area

The most critical contingency is the loss of the Herndon -Barton 115 kV line along with Herndon-Woodward 115 kV line. This contingency could thermally overload the Herndon–Manchester 115 kV line. This limiting contingency establishes a LCR of 275 MW (includes 41 MW of QF and 99 MW of Muni generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The Category B LCR requirement for the Herndon sub area was eliminated due to the construction of the new Herndon# 3 230/115 kV transformer bank.

Effectiveness factors:

The following table has units within Fresno area that are relatively effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34308	KERCKHOF	1	34%
34344	KERCKHOF	1	34%
34344	KERCKHOF	2	34%
34344	KERCKHOF	3	34%
34624	BALCH 1	1	33%
34646	SANGERCO	1	31%
34616	KINGSRIV	1	31%
34671	KRCDPCT1	1	31%
34672	KRCDPCT2	1	31%
34640	ULTR.PWR	1	30%
34648	DINUBA E	1	28%
34642	KINGSBUR	1	25%
34696	Q478	1	25%
38720	PINE FLT	1	23%
38720	PINE FLT	2	23%
38720	PINE FLT	3	23%
34610	HAAS	1	23%
34610	HAAS	2	23%
34614	BLCH 2-3	1	23%
34612	BLCH 2-2	1	23%
34431	GWF_HEP1	1	14%
34433	GWF_HEP2	1	14%
34301	CHOWCOGN	1	9%

34305	CHWCHLA2	1	9%
34608	AGRICO	2	7%
34608	AGRICO	3	7%
34608	AGRICO	4	7%
34332	JRWCOGEN	1	-6%
34600	HELMS 1	1	-12%
34602	HELMS 2	1	-12%
34604	HELMS 3	1	-12%
34485	FRESNOWW	1	-14%

Henrietta Sub-area

The two most critical contingencies listed below together establish a local capacity need of 68 MW (includes 24 MW of QF as well as 8 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 36 MW in 2011 (includes 0 MW of QF generation).

The second most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV line. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 32 MW in 2011 (includes 24 MW of QF generation as well as 8 MW of deficiency).

The most critical single contingency is the loss of Henrietta 230/70 kV transformer bank #4. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 35 MW in 2012 (includes 24 MW of QF generation).

Effectiveness factors:

All units within this sub-area have the same effectiveness factor. Units outside of this sub-area are not effective.

Changes compared to last year's results:

Overall the load forecast is down by 186 MW. Path 15 flow is 1275 MW N-S the same as last year. Due to the new Herndon # 3 230/115 kV bank & lower load forecast, the total Fresno LCR requirement has decreased by 542 MW.

Fresno Area Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	189	167	2414	2770

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	1873	0	1873
Category C (Multiple) [20]	1899	8	1907

7. Kern Area

<u>Area Definition</u>

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

1) Wheeler Ridge-Lamont 115 kV line
2) Kern PP 230/115 kV Bank # 3
3) Kern PP 230/115 kV Bank # 4
4) Kern PP 230/115 kV Bank # 5
5) Midway 230/115 Bank # 1
6) Midway 230/115 Bank # 2
7) Midway 230/115 Bank #3
8) Temblor – San Luis Obispo 115 kV line

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

1) Wheeler Ridge is out Lamont is in
2) Kern PP 230 kV is out Kern PP 115 kV is in
3) Kern PP 230 kV is out Kern PP 115 kV is in
4) Kern PP 230 kV is out Kern PP 115 kV is in

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

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

5) Midway 230 kV is out Midway 115 kV is in
6) Midway 230 kV is out Midway 115 kV is in
7) Midway 230 kV is out Midway 115 kV is in
8) Temblor is in San Luis Obispo is out

The transmission facilities coming into the Weedpatch sub-area are:

1) Wheeler Ridge-Tejon 60 kV line
2) Wheeler Ridge-Weedpach 60 kV line
3) Wheeler Ridge-San Bernard 60 kV line

The substations that delineate the Weedpatch sub-area are:

1) Wheeler Ridge is out Tejon is in
2) Wheeler Ridge is out Weedpach is in
3) Wheeler Ridge is out San Bernard is in

2012 total busload within the defined area: 1099 MW with 11 MW of losses resulting in a total (load plus losses) of 1110 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BDGRCK_1_UNITS	35029	BADGERCK	9.11	42.21	1	Kern PP	Aug NQC	QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	45.79	1	Kern PP, West Park	Aug NQC	QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	45.27	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	1.27	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	5.24	1	Kern PP	Aug NQC	QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	28.24	1	Kern PP	Aug NQC	QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	1.70	1	Kern PP	Aug NQC	QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	37.59	1	Kern PP	Aug NQC	QF/Selfgen
FELLOW_7_QFUNTS				1.28		Kern PP	Not modeled Aug NQC	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.09	1	Kern PP	Aug NQC	QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	37.60	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.51	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.51	2	Kern PP	Aug NQC	QF/Selfgen
KRNCNY_6_UNIT	35018	KERNCNYN	9.11	9.38	1	Weedpatch	Aug NQC	Market
KRNOIL_7_TEXEXP				6.11		Kern PP	Not modeled Aug NQC	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.40	1	Kern PP	Aug NQC	QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	33.56	1	Kern PP	Aug NQC	QF/Selfgen
MIDWAY_1_QF				0.03		Kern PP	Not modeled Aug NQC	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	43.07	1	Kern PP	Aug NQC	QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	43.39	1	Kern PP	Aug NQC	QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	1	Kern PP	Aug NQC	QF/Selfgen

NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	2	Kern PP	Aug NQC	QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	37.50	1	Kern PP	Aug NQC	QF/Selfgen
RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.11	6.50	1	Weedpatch	Aug NQC	QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	42.98	1	Kern PP	Aug NQC	QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	9.79	1	Kern PP	Aug NQC	QF/Selfgen
TEMBLR_7_WELLPT				0.30		Kern PP	Not modeled Aug NQC	QF/Selfgen
TXMCKT_6_UNIT				4.12		Kern PP	Not modeled Aug NQC	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	1	Kern PP	Aug NQC	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	2	Kern PP	Aug NQC	QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.70	1	Kern PP	Aug NQC	QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	31.66	1	Kern PP	Aug NQC	QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	8.01	1	Kern PP	Aug NQC	QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	0.00	1	Kern PP	Retired	Market
NA	35056	TX-LOSTH	4.16	8.80	1	Kern PP	No NQC - hist. data	QF/Selfgen
New Unit	35000	Q340	21	0.00	1	Kern PP	Energy Only	Market
New Unit	35012	Q473	21	0.00	1	Kern PP	Energy Only	Market
New Unit	35013	Q479	21	0.00	1	Kern PP	Energy Only	Market

Major new projects modeled:

1. Kern Bank 3 & 3a 230/115 kV bank replacement
2. Midway Bank 2 & 2a 230/115 kV bank replacement

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency is the outage of the Kern PP #5/#3 230/115 kV transformer bank followed by the Kern PP – Kern Front 115 kV line, which could thermally overload the parallel Kern PP #4 230/115 kV transformer. This limiting contingency establishes a LCR of 296 MW in 2012 (includes 596 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 loss of Kern PP #5 or #3 230/115 kV transformer bank, which could thermally overload the parallel Kern PP #4230/115 kV transformer. This limiting contingency establishes a LCR of 180 MW in 2012 (includes 596 MW of QF generation).

Effectiveness factors:

The following table shows units that are at least 5% effective:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35066	PSE-BEAR	1	22%
35029	BADGERCK	1	22%
35023	DOUBLE C	1	22%
35027	HISIERRA	1	22%
35026	KERNFRNT	1	21%
35058	PSE-LVOK	1	21%
35028	OILDALE	1	21%
35062	DISCOVRY	1	21%
35046	SEKR	1	21%
35024	DEXEL +	1	21%
35036	MT POSO	1	15%
35035	ULTR PWR	1	15%
35052	CHEV.USA	1	6%

Weedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line followed by the Wheeler Ridge – Tejon 70 kV line, which could thermally overload the Wheeler Ridge – Weedpatch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a LCR of 30 MW in 2012 (includes 7 MW of QF generation and 14 MW of deficiency) as the minimum generation 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.

West Park Sub-area

The most critical contingency is the loss of common mode Kern - West Park # 1 & #2 115 kV lines, resulting in the overload of the 6/42 To Magunden section of Kern – Magunden - Witco 115 kV line. This limitation establishes a LCR of 60 MW (includes 46 MW of QF generation and 14 MW of deficiency).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went down by 277 MW and that drives the LCR down by 138 MW. The load reduction is less effective in mitigating the main Kern PP constraint compared to resources in the area.

Kern Area Overall Requirements:

2012	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	602	9	611

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[21]	180	0	180
Category C (Multiple)[22]	297	28	325

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

[21] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[22] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

These sub-stations form the boundary surrounding the LA Basin area:

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

Total 2012 busload within the defined area is 19,774 MW with 129 MW of losses and 27 MW pumps resulting in total load + losses + pumps of 19,930 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
ANAHM_7_CT	25203	ANAHEIMG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	56.62	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	56.62	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	56.62	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	56.62	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	28.31	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	28.32	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	28309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	28007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.11	W5	Eastern	Aug NQC	Wind
CABZON_1_WINDA1	28280	CABAZON	33	8.81	1	Eastern	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	17.99		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen

CENTER_6_PEAKER	28308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4				36.00		Eastern	Not modeled Aug NQC	Market
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.15	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.16	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	9.30		Western	Not modeled Aug NQC	QF/Selfgen
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.07	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	25.07	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SOLAR	24024	CHINO	66	0.00		Western	Not modeled	Market
CHINO_7_MILIKN	24024	CHINO	66	1.26		Western	Not modeled Aug NQC	Market
COLTON_6_AGUAM1				43.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
DEVERS_1_QF	25645	VENWIND	115	1.08	EU	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	0.96	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.42	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.53	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.57	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.77	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	1.61	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.71	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	1.90	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	24815	GARNET	115	1.07	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.08	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.40	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.22	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	4.72	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	1.42	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	1.27	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.19	W1	Eastern	Aug NQC	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	21.00		Eastern	Not modeled	QF/Selfgen
DREWS_6_PL1X4				36.00		Eastern	Not modeled Aug NQC	Market
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.15	4	Eastern	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.11		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.67		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	15.11		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_6_GRPLND	28305	ETWPKGEN	13.8	42.53	1	Eastern		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	15.56	1	Eastern	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.58		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	Eastern		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	Eastern		Market

GARNET_1_UNITS	24815	GARNET	115	0.57	G1	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.20	G2	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.41	G3	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.20	PC	Eastern	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.66	W2	Eastern	Aug NQC	Wind
GARNET_1_WIND	24815	GARNET	115	0.66	W3	Eastern	Aug NQC	Wind
GLNARM_7_UNIT 1	28005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	28006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	28005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	22.67	1	Western	Aug NQC	Market
HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	27.67	1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	225.00	3	Western, Ellis		Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	227.00	4	Western, Ellis		Market
INDIGO_1_UNIT 1	28190	WINTECX2	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 2	28191	WINTECX1	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 3	28180	WINTEC8	13.8	42.00	1	Eastern		Market
INLDEM_5_UNIT 1	28041	IEEC-G1	19.5	335.00	1	Eastern	Aug NQC	Market
INLDEM_5_UNIT 2	28042	IEEC-G2	19.5	335.00	1	Eastern	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24208	LCIENEGA	66	4.39		Western	Not modeled Aug NQC	QF/Selfgen
LAFRES_6_QF	24073	LA FRESA	66	2.89		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.90		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	45.72	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.95		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.15		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.12		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_TEMESC				2.41		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	32.04	1	Eastern	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	28307	MRLPKGEN	13.8	43.18	1	Eastern		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	3.90		Eastern	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	1	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	2	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	3	Eastern	Aug NQC	Market
MTWIND_1_UNIT 1				5.13		Eastern	Not modeled Aug NQC	Wind
MTWIND_1_UNIT 2				2.10		Eastern	Not modeled Aug NQC	Wind

MTWIND_1_UNIT 3				2.07		Eastern	Not modeled Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	1.02	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.50		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.63		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	5.60		Eastern	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	2.18		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern	Not modeled Aug NQC	QF/Selfgen
PWEST_1_UNIT				0.22		Western	Not modeled Aug NQC	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	1.62		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	4.22	1	Western, Ellis	Aug NQC	Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	Eastern		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	Eastern		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.17		Eastern	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.05		Eastern	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.08		Eastern	Not modeled Aug NQC	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	Western		Nuclear
TIFFNY_1_DILLON				6.37		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	0.16		Eastern	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.38		Eastern	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.13		Eastern	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	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	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	4.30		Western	Not modeled Aug NQC	MUNI
VISTA_6_QF	24902	VSTA	66	0.26	1	Eastern	Aug NQC	QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	46.68	1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	3.43		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	2.98		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	28061	WHITEWTR	33	6.61	1	Eastern	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	Eastern	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	0.00	1	Western	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	24337	VENICE	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	18.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	25301	CLTNDREW	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	25302	CLTNCTRY	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	25303	CLTNAGUA	13.8	45.00	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	29338	CLEARGEN	13.8	0.00	1	Eastern	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	Eastern	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	Eastern	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.20	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	50.00	1	Eastern	No NQC - Pmax	MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	50.00	1	Eastern	No NQC - Pmax	MUNI

Major new projects modeled:

1. 2 small new resources have been modeled

Critical Contingency Analysis Summary

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one Songs unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,865 MW in 2012 (includes 850 MW of QF, 33 MW of Wind, 900 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned South of Lugo constraint within the LA Basin area:

Gen Bus	Gen Name	Gen ID	MW Eff. Fact (%)
24052	MTNVIST3	3	34
24053	MTNVIST4	4	34
24071	INLAND	1	33
25422	ETI MWDG	1	33
29305	ETWPKGEN	1	33
24905	RVCANAL1	R1	26
24906	RVCANAL2	R2	26
24907	RVCANAL3	R3	26
24908	RVCANAL4	R4	26
24921	MNTV-CT1	1	26
24922	MNTV-CT2	1	26
24923	MNTV-ST1	1	26
24924	MNTV-CT3	1	26
24925	MNTV-CT4	1	26
24926	MNTV-ST2	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24244	SPRINGEN	1	26
25301	CLTNDREW	1	26
25302	CLTNCTRY	1	26

25303	CLTNAGUA	1	26
25603	DVLCYN3G	3	25
25604	DVLCYN4G	4	25
25648	DVLCYN1G	1	24
25649	DVLCYN2G	2	24
29041	IEEC-G1	1	24
29042	IEEC-G2	2	24
25203	ANAHEIMG	1	22
25632	TERAWND	QF	22
25634	BUCKWND	QF	22
25635	ALTWIND	Q1	22
25635	ALTWIND	Q2	22
25637	TRANWND	QF	22
25639	SEAWIND	QF	22
25640	PANAERO	QF	22
25645	VENWIND	EU	22
25645	VENWIND	Q2	22
25645	VENWIND	Q1	22
25646	SANWIND	Q2	22
29190	WINTECX2	1	22
29191	WINTECX1	1	22
29180	WINTEC8	1	22
24815	GARNET	QF	22
24815	GARNET	W3	22
24815	GARNET	W2	22
29023	WINTEC4	1	22
29060	SEAWEST	S1	22
29060	SEAWEST	S3	22
29060	SEAWEST	S2	22
29260	ALTAMSA4	1	22
29290	CABAZON	1	22
29021	WINTEC6	1	22
25657	MJVSPHN1	1	22
25658	MJVSPHN2	2	22
25659	MJVSPHN3	3	22
24030	DELGEN	1	21
25633	CAPWIND	QF	21
29061	WHITEWTR	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29309	BARPKGEN	1	20
29307	MRLPKGEN	1	19
29338	CLEARGEN	1	19

29339	DELGEN	1	19
24066	HUNT1 G	1	18
24067	HUNT2 G	2	18
24167	HUNT3 G	3	18
24168	HUNT4 G	4	18
24129	S.ONOFR2	2	18
24130	S.ONOFR3	3	18
24133	SANTIAGO	1	18
24325	ORCOGEN	1	18
24341	COYGEN	1	18
24001	ALAMT1 G	1	17
24002	ALAMT2 G	2	17
24003	ALAMT3 G	3	17
24004	ALAMT4 G	4	17
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	16
29209	BLY1ST1	1	15
29207	BLY1CT1	1	15
29208	BLY1CT2	1	15
29953	SIGGEN	D1	15
24018	BRIGEN	1	14
24020	CARBGEN1	1	14
24064	HINSON	1	14
24070	ICEGEN	D1	14
24170	LBEACH12	2	14
24171	LBEACH34	3	14
24079	LBEACH7G	7	14
24080	LBEACH8G	8	14
24081	LBEACH9G	9	14
24062	HARBOR G	1	14
25510	HARBORG4	LP	14
24062	HARBOR G	HP	14
29308	CTRPKGEN	1	14
24139	SERRFGEN	D1	14
24170	LBEACH12	1	14
24171	LBEACH34	4	14
24173	LBEACH5G	R5	14
24174	LBEACH6G	R6	14
24327	THUMSGEN	1	14
24328	CARBGEN2	1	14
24337	VENICE	1	14

24011	ARCO 1G	1	13
24012	ARCO 2G	2	13
24013	ARCO 3G	3	13
24014	ARCO 4G	4	13
24163	ARCO 5G	5	13
24164	ARCO 6G	6	13
24022	CHEVGEN1	1	13
24023	CHEVGEN2	2	13
24047	ELSEG3 G	3	13
24048	ELSEG4 G	4	13
24094	MOBGEN1	1	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
24329	MOBGEN2	1	13
24330	OUTFALL1	1	13
24331	OUTFALL2	1	13
24332	PALOGEN	D1	13
24333	REDON1 G	R1	13
24334	REDON2 G	R2	13
24335	REDON3 G	R3	13
24336	REDON4 G	R4	13
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29951	REFUSE	D1	11
24342	FEDGEN	1	11
29007	BRODWYSC	1	9
29005	PASADNA1	1	8
29006	PASADNA2	1	8

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line. This limiting contingency establishes a LCR of 5785 MW (includes 559 MW of QF, 6 MW of Wind, 387 MW of Muni and 2246 MW of nuclear generation) in 2012 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

There are numerous (about 40) other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-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, effectiveness factors are not given since they would most likely not facilitate more informed procurement.

Ellis sub-area

The most critical contingency for the Ellis sub-area is the loss of the Barre to Ellis 230 kV line followed by the loss of the Santiago to S.Onofre #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 474 MW in 2012 (which includes 18 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

El Nido sub-area

There are two most critical contingencies for the El Nido sub-area that cause the same LCR need:

1. The loss of the La Fresa-Redondo #1 and #2 230 kV lines which could overload La Fresa-Hinson 230 kV line.
2. The loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse.

These two limiting contingencies establish a LCR of 362 MW in 2012 (which includes 27 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 45 MW resulting in an increase in LCR by 276 MW. The higher LCR increase is due in part to load allocation change, between LA Basin, Big Creek Ventura and the rest of SCE system based on new CEC load forecast and the decrease in LCR needs for the San Diego area due to the new Sunrise Power Link.

LA Basin Overall Requirements:

2012	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	883	900	2246	8054	12083

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[23]	10,865	0	10,865
Category C (Multiple)[24]	10,865	0	10,865

9. Big Creek/Ventura Area

Area Definition

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

1) Vincent-Antelope #1 230 kV Line
2) Vincent-Antelope #2 230 kV Line
3) Sylmar-Pardee #1 230 kV Line
4) Sylmar-Pardee #2 230 kV Line
5) Eagle Rock-Pardee #1 230 kV Line
6) Vincent-Pardee 230 kV Line
7) Vincent-Santa Clara 230 kV Line

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

[23] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[24] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

1) Vincent is out Antelope is in
2) Vincent is out Antelope is in
3) Sylmar is out Pardee is in
4) Sylmar is out Pardee is in
5) Eagle Rock is out Pardee is in
6) Vincent is out Pardee is in
7) Vincent is out Santa Clara is in

Total 2012 busload within the defined area is 4260 MW with 78 MW of losses and 355 MW of pumps resulting in total load + losses + pumps of 4693 MW.

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
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek	Aug NQC	Market
ANTLPE_2_QF	24457	ARBWIND	66	2.90	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24458	ENCANWND	66	15.03	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24459	FLOWIND	66	5.43	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	1.86	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24465	MORWIND	66	7.45	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24491	OAKWIND	66	2.40	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28501	MIDWIND	12	2.40	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	0.88	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28503	NORTHWND	12	2.58	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	1.76	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	1.70	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.60	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.06	1	Big Creek	Aug NQC	Wind
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	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	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	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	24308	B CRK2-1	13.8	50.64	2	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	24318	MAMOTH2G	13.8	91.07	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	24309	B CRK2-2	7.2	18.22	3	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	24309	B CRK2-2	7.2	19.19	4	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	24310	B CRK2-3	7.2	16.55	5	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	24310	B CRK2-3	7.2	18.02	6	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	24314	B CRK 4	11.5	49.28	42	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	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	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	24.11	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	24.11	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	24.11	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	24.11	4	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	24.11	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	24.11	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	24.11	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	24.11	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	24.11	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	24.11	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	24.10	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	24.10	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	24.10	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	24.10	14	Big Creek	Pumps	MUNI
GOLETA_2_QF	24057	GOLETA	66	0.17		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	0.35		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	1.50		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.77		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	11.75	1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market

LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	Aug NQC	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MONLTH_6_BOREL	24456	BOREL	66	8.75	1	Big Creek	Aug NQC	QF/Selfgen
MOORPK_2_CALABS	24099	MOORPARK	230	6.96		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.61		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	1.10		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
OMAR_2_UNITS	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	3	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	6	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	21.61	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	17.61	2	Big Creek, Vestal	Aug NQC	QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	0.30		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	0.41		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	2.34		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	1.60		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_6_MWDFTH	24135	SAUGUS	66	6.40		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	20.31	1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	1.17		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.37		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	32.53	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.65	1	Ventura, S.Clara,	Aug NQC	Market

						Moorpark		
SNCLRA_6_QF	24127	S.CLARA	66	1.73	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	12.64	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.19		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.23		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.42		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	64.47	1	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	64.47	2	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	64.47	3	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	64.46	4	Big Creek	Aug NQC	QF/Selfgen
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.39	1	Big Creek	Aug NQC	Market
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.38	2	Big Creek	Aug NQC	Market
VESTAL_2_KERN	24152	VESTAL	66	2.02	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	2.17		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.76	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	5.68	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	Market
NA	24340	CHARMIN	13.8	15.20	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24372	KR 3-1	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24373	KR 3-2	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market
NA	24436	GOLDTOWN	66	0.00	1	Big Creek	No NQC - hist. data	Market
NA	24362	Exgen2	13.8	0.00	G1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24326	Exgen1	13.8	0.00	S1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen

Major new projects modeled: None

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The most critical contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 3093 MW in 2012 (includes 762 MW of QF, 383 MW of Muni and 46 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The second most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 3009 MW in 2012 (includes 762 MW of QF, 383 MW of Muni and 46 MW of Wind generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to any one of the Sylmar-Pardee 230 kV lines after the loss of the Lugo-Victorville 500 kV followed by one of the other Sylmar-Pardee 230 kV line in this area:

Gen Bus	Gen Name	Gen ID	MW Eff. Fctr. (%)
24009	APPGEN1G	1	29
24010	APPGEN2G	2	29
24107	ORMOND1G	1	29
24108	ORMOND2G	2	29
24118	PITCHGEN	1	28
24148	TENNGEN1	1	28
24149	TENNGEN2	2	28
24089	MANDLY1G	1	27
24090	MANDLY2G	2	27
24110	OXGEN	1	27
24119	PROCGEN	1	27
24159	WILLAMET	1	27
25651	WARNE1	1	27
25652	WARNE2	1	27
28004	ELLWOOD	1	27
24361	EXGEN1	1	27
24362	EXGEN2	2	27
28051	PSTRIAG1	G1	26
25606	EDMON2AP	2	26

25607	EDMON3AP	3	26
25607	EDMON3AP	4	26
25608	EDMON4AP	5	26
25608	EDMON4AP	6	26
25609	EDMON5AP	7	26
25609	EDMON5AP	8	26
25610	EDMON6AP	9	26
25610	EDMON6AP	10	26
25611	EDMON7AP	11	26
25611	EDMON7AP	12	26
25612	EDMON8AP	13	26
25612	EDMON8AP	14	26
28054	PSTRIAG3	G3	25
25615	OSO B P	7	25
25615	OSO B P	8	25
28952	CAMGEN	13.8	25
24127	S.CLARA	1	25
24340	CHARMIN	1	25
28055	PSTRIAS2	S2	24
28053	PSTRIAS1	S1	24
28052	PSTRIAG2	G2	24
25605	EDMON1AP	1	24
24143	SYCCYN1G	1	24
24144	SYCCYN2G	2	24
24145	SYCCYN3G	3	24
24146	SYCCYN4G	4	24
24102	OMAR 1G	1	23
24103	OMAR 2G	2	23
24104	OMAR 3G	3	23
24105	OMAR 4G	4	23
25614	OSO A P	1	23
25614	OSO A P	2	23
25653	ALAMO SC	1	23
24222	MANDLY3G	3	20
28008	LAKEGEN	1	20
24150	ULTRAGEN	1	20
24152	VESTAL	1	20
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	20
24306	B CRK1-1	1	20
24306	B CRK1-1	2	20
24307	B CRK1-2	3	20
24307	B CRK1-2	4	20
24308	B CRK2-1	1	20
24308	B CRK2-1	2	20
24309	B CRK2-2	3	20
24309	B CRK2-2	4	20
24310	B CRK2-3	5	20

24310	B CRK2-3	6	20
24311	B CRK3-1	1	20
24311	B CRK3-1	2	20
24312	B CRK3-2	3	20
24312	B CRK3-2	4	20
24313	B CRK3-3	5	20
24314	B CRK 4	41	20
24314	B CRK 4	42	20
24315	B CRK 8	81	20
24315	B CRK 8	82	20
24317	MAMOTH1G	1	20
24318	MAMOTH2G	2	20
24113	PANDOL	1	19
24113	PANDOL	2	19
24437	KERNRVR	1	18
24459	FLOWIND	1	14
24436	GOLDTOWN	1	14
28501	MIDWIND	1	14
24457	ARBWIND	1	13
24456	BOREL	1	12
24458	ENCANWND	1	12
24460	DUTCHWND	1	12
24465	MORWIND	1	12
28503	NORTHWND	1	12
28504	ZONDWND1	1	12
28505	ZONDWND2	1	12
25618	PEARBMBP	5	6
25618	PEARBMBP	6	6
25619	PEARBMCP	7	6
25619	PEARBMCP	8	6
25617	PEARBMAP	1	5
25617	PEARBMAP	2	5
25620	PEARBMDP	9	5
24136	SEAWEST	1	5

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 525 MW (includes 4 MW of QF generation) in 2012 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	Eff Fctr (%)
24370	KAWGEN	1	45
24319	EASTWOOD	1	41
24306	B CRK1-1	1	41
24306	B CRK1-1	2	41
24307	B CRK1-2	3	41
24307	B CRK1-2	4	41
24323	PORTAL	1	41
24308	B CRK2-1	1	40
24308	B CRK2-1	2	40
24309	B CRK2-2	3	40
24309	B CRK2-2	4	40
24315	B CRK 8	81	40
24315	B CRK 8	82	40
24310	B CRK2-3	5	39
24310	B CRK2-3	6	39
24311	B CRK3-1	1	39
24311	B CRK3-1	2	39
24312	B CRK3-2	3	39
24312	B CRK3-2	4	39
24313	B CRK3-3	5	39
24317	MAMOTH1G	1	39
24318	MAMOTH2G	2	39
24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 776 MW in 2012 (which includes 88 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	Eff Fctr (%)
28008	LAKEGEN	1	46
24113	PANDOL	1	45
24113	PANDOL	2	45
24150	ULTRAGEN	1	45
24372	KR 3-1	1	45
24373	KR 3-2	2	45

24152	VESTAL	1	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	24
24306	B CRK1-1	1	24
24306	B CRK1-1	2	24
24307	B CRK1-2	3	24
24307	B CRK1-2	4	24
24308	B CRK2-1	1	24
24308	B CRK2-1	2	24
24309	B CRK2-2	3	24
24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24
24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23
24314	B CRK 4	41	22
24314	B CRK 4	42	22

S. Clara sub-areas

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 296 MW in 2012 (which includes 64 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Moorpark sub-areas

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 377 MW in 2012 (which includes 92 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 45 MW. The overall effect is that the LCR has increase by 307 MW. The higher LCR increase is due to load allocation change within the Big Creek Ventura.

Big Creek Overall Requirements:

2012	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	808	383	4041	5232

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[25]	3093	0	3093
Category C (Multiple)[26]	3093	0	3093

10. San Diego Area

Area Definition

The transmission tie lines forming a boundary around San Diego include:

1) Imperial Valley – Miguel 500 kV Line
2) Imperial Valley – Central 500kV Line
3) Otay Mesa – Tijuana 230 kV Line
4) San Onofre - San Luis Rey #1 230 kV Line
5) San Onofre - San Luis Rey #2 230 kV Line
6) San Onofre - San Luis Rey #3 230 kV Line
7) San Onofre – Talega #1 230 kV Line

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

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

8) San Onofre – Talega #2 230 kV Line

The substations that delineate the San Diego Area are:

1) Imperial Valley is out Miguel is in
2) Imperial Valley is out Central is in
3) Otay Mesa is in Tijuana is out
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 San Luis Rey is in
7) San Onofre is out Talega is in
8) San Onofre is out Talega is in

Total 2012 busload within the defined area: 4770 MW with 74 MW of losses resulting in total load + losses of 4844 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
BORDER_6_UNITA1	22149	CALPK_BD	13.8	43.80	1	Border		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.15	1		Aug NQC	QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	2.63	1		Aug NQC	QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.43	1		Aug NQC	QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.26	2		Aug NQC	QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	3.49	1		Aug NQC	QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	6.46	1		Aug NQC	Wind
DIVSON_6_NSQF	22172	DIVISION	69	36.47	1		Aug NQC	QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	0.21	1		Aug NQC	QF/Selfgen
ELCAJN_6_LM6K	23320	C509	13.8	48.00	1	El Cajon		Market
ELCAJN_6_UNITA1	22150	CALPK_EC	13.8	42.20	1	El Cajon		Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	16.00	1	El Cajon		Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1			Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	104.00	1			Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	110.00	1			Market
ENCINA_7_EA4	22240	ENCINA 4	22	300.00	1			Market
ENCINA_7_EA5	22244	ENCINA 5	24	330.00	1			Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.00	1			Market
ESCNDO_6_PL1X2	22257	ESGEN	13.8	35.50	1			Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	45.50	1			Market
ESCO_6_GLMQF	22332	GOALLINE	69	44.04	1	Esco	Aug NQC	QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	16.00	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	15.02	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	2	Rose Canyon, Mission		Market

KEARNY_7_KY2	22374	KEARN2CD	12.5	13.95	2	Rose Canyon, Mission		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.98	1	Rose Canyon, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	1	Rose Canyon, Mission		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	16.05	2	Rose Canyon, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	2	Rose Canyon, Mission		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	Border		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	Border		Market
MRGT_6_MEF2	22487	MFE_MR2	13.8	47.90	1	Mission		Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	46.60	1	Mission		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	18.55	1	Mission		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.45	2	Mission		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	2.94	1	Mission	Aug NQC	QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.80	1		Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	34.16	1		Aug NQC	QF/Selfgen
OGROVE_6_PL1X2	22628	PA99MWQ1	13.8	49.95	1			Market
OGROVE_6_PL1X2	22629	PA99MWQ2	13.8	49.95	2			Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1			Market
OTAY_6_UNITB1	22604	OTAY	69	2.90	1		Aug NQC	QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	2.70	3		Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1			Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1			Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1			Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.17	1			Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.17	1			Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.66	1			Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	1.64	2		Aug NQC	QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	17.18	1		Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1				2.72			Aug NQC	QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.65	1		Aug NQC	QF/Selfgen
NA	22916	PFC-AVC	0.6	0.00	1		No NQC - hist. data	QF/Selfgen
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	Bernardo	No NQC - Pmax	Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	Bernardo	No NQC - Pmax	Market
New unit	23120	BULLMOOS	13.8	27.00	1	Border	No NQC - Pmax	Market

Major new projects modeled:

1. Sunrise Power Link Project (Southern Route)
2. 3 small new resources and the LGIP upgrades associated with Bullmoose Project (Otay – Otay Lake Tap 69kV, TL649 reconductor)
3. Retirement of South Bay Power Plant
4. Eastgate – Rose Canyon 69kV (TL6927) reconductor

<u>Critical Contingency Analysis Summary</u>

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 Miguel-Granite-Los Coches 69 kV line (TL632), which would thermally overload the Garfield-Murray 69 kV line. This limiting contingency establishes a LCR of 35 MW (including 0 MW of QF generation) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (El Cajon Peaker, El Cajon GT, and new peaker at El Cajon substation) have the same effectiveness factor.

Rose Canyon Sub-area

This sub-area has been eliminated due to recently approved transmission project, TL6927, Eastgate-Rose Canyon 69 kV reconductor. If the project reconductoring is delayed beyond June 1, 2012, the most critical contingency for the Rose Canyon sub area will be the loss of Imperial Valley – Miguel 500kV line (TL50001) followed by the loss of Rose Canyon – Miramar - Penasquitos 69kV line (TL664A) would thermally overload Eastgate – Rose Canyon 69kV line (TL6927). This limiting contingency would establish a local capacity need of 53 MW (includes 0 MW of QF generation) in 2012.

Effectiveness factors:

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

Mission Sub-area

The most critical contingency for the Mission sub-area is the loss of Mission - Kearny 69 kV line (TL663) followed by the loss of Mission – Mesa Heights 69kV line (TL676), which would thermally overload the Mission - Clairmont 69kV line (TL670). This limiting contingency establishes a local capacity need of 233 MW (including 3 MW of QF generation) in 2012.

Effectiveness factors:

Miramar Energy Facility units and Miramar GTs (Cabrillo Power II) are 6% effective, Miramar Landfill unit and all Kearny peakers are 32% effective.

Bernardo Sub-area:

The most critical contingency for the Bernardo sub-area is the loss of Artesian - Sycamore 69 kV line followed by the loss of Poway-Rancho Carmel 69 kV line, which would thermally overload the Felicita Tap-Bernardo 69 kV line (TL689)
This limiting contingency establishes a LCR of 105 MW (including 0 MW of QF generation and 65 MW of deficiency) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Lake Hodges) are needed so there is no effectiveness factor required.

Border Sub-area

Sub-area eliminated due to new generation project upgrade, reconductor TL649A, Otay-Otay Lakes Tap 69 kV. If the project reconductoring is delayed beyond June 1, 2012, the most critical contingency for the Border sub area will be the loss of Border – Miguel 69 kV line (TL6910) followed by the loss of Imperial Beach-Otay-San Ysidro 69 kV line (TL623), which would thermally overload Otay-Otay Lake Tap (TL649). This limiting contingency would establish a local capacity need of 27 MW (includes 0 MW of QF generation) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:

If the reconductoring project is completed by June 1, 2012, no units will be needed. If the project is not completed, Border Cal Peak, Larkspur and Bullmoose all have the same effectiveness factor.

Esco Sub-area

The most critical contingency for the Esco sub-area is the loss of Poway-Pomerado 69 kV line followed by the loss of Bernardo-Rancho Carmel 69kV line which would thermally overload the Esco-Escondido 69 kV lineThis limiting contingency establishes a LCR of 74 MW (including 44 MW of QF generation and 30 MW of deficiency) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

Only unit within this sub-area (Goal line) is needed so no effectiveness factor is required.

San Diego overall:

The most limiting contingency in the San Diego area is described by the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the 1000 MW rating of Imperial Valley - Central 500 kV line (Sunrise Power Link). Post-contingency import limit of 3,500 MW is not the most limiting condition here. Sunrise Power Link hits 1,000 MW before SDGE import hits 3,500 MW. This contingency establishes a LCR of 2849 MW in 2012 (includes 156 MW of QF generation and 6 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this area.

If the Sunrise Power Link is delayed beyond June 1, 2012, the most critical contingency for the San Diego overall area will be the loss of Imperial Valley – Miguel 500 kV line with Otay Mesa Power Plant out of service, which would require the system to be within the South of SONGS path rating of 2500 MW. This limiting contingency would establish a local capacity need of 2989 MW (includes 156 MW of QF generation and 6 MW of Wind) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Greater IV-San Diego area:

The most limiting contingency in the Greater Imperial Valley-San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This limiting contingency establishes a local capacity need of 2804 MW in 2012 as the minimum capacity necessary for reliable load serving capability within this area. It is worth mentioning that there were no additional upgrades modeled between the IID and CAISO or CFE and CAISO control areas at Imperial Valley 230 kV bus in 2012 base case. The CAISO acknowledges that the LCR needs for the Greater Imperial Valley-San Diego area will decrease as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these control areas into the CAISO control area.

The Greater Imperial Valley/San Diego area and San Diego Overall LCR needs are very similar in magnitude. In future years, either of these areas may become more stringent depending on the study assumptions and future projects.

The CAISO will continue to use the existing San Diego boundary as a local area for year 2012 because the requirements of the Greater Imperial Valley/San Diego area are not binding during 2012 and because a delay in Sunrise Power Link construction would require even higher local requirement within the existing San Diego area.

Changes compared to last year's results:

Overall the load forecast went down by 182 MW and total resource capacity needed for LCR decreased by 297 MW. The addition of Sunrise Power Link is the reason for the further decrease in LCR beyond load forecast.

San Diego Overall Requirements:

2012	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	156	6	2925	3087

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[27]	2849	0	2849
Category C (Multiple)[28]	2849	95	2944

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

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

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.	)))))	Rulemaking 09-10-032 (Filed October 29, 2009)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
NOTICE OF AVAILABILITY OF
2012 LOCAL CAPACITY TECHNICAL ANALYSIS
FINAL REPORT AND STUDY RESULTS

In accordance with Rule 1.9(c) of the Commission's Rules of Practice and Procedure and the Revised Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge Determining the Scope, Schedule, and Need for Hearing in this Proceeding, issued on February 3, 2011, the California Independent System Operator Corporation respectfully serves this notice informing parties of the availability of the ISO's 2012 Local Capacity Technical Analysis Final Report And Study Results ("2012 LCR Study"). Because the 2012 LCR Study exceeds 50 pages, the ISO is serving this notice of availability in lieu of the document.

The 2012 LCR Study, filed with the Commission on May 2, 2011, is available on the ISO's website at:

http://www.caiso.com/2b79/2b79a0f839e60.pdf

In addition, consistent with Rule 1.9, a copy of the document may be requested by telephone at 916-351-2212 or by email at apascusso@caiso.com.

Respectfully submitted,

/s/ Beth Ann Burns

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Date: May 2, 2011

CERTIFICATE OF SERVICE

I hereby certify that on May 18, 2011 I served, by electronic and United States mail, a copy of the foregoing California Independent System Operator Corporation Notice of Availability of 2012 Local Capacity Technical Analysis Final Report and Study Results to each party in Docket No. R.09-10-032.

Executed on May 18, 2011
at Folsom, California

/s/ Susan L. Montana /s/

Susan L. Montana
An Employee of the California
Independent System Operator