California Independent
System Operator

2011-2013
LOCAL CAPACITY TECHNICAL ANALYSIS

REPORT
AND STUDY RESULTS

December 29, 2008

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

This Report documents the results and recommendations of the 2011 and 2013 Long-Term Local Capacity Technical (LCT) Study. The LCT Study objectives, inputs, methodologies and assumptions are the same as those discussed in the 2009 LCT Study and already adopted by the CAISO and CPUC in their 2009 Local Resource Adequacy needs.

Most LCR requirements trend up by about 2%/year mainly due to load forecast increase. However overall they decrease (over 800 MW for 2013) mainly due to new transmission projects. For comparison below you will find the 2009, 2011 and 2013 total LCR needs.

2009 Local Capacity Needs

	Qualifying Capacity			2009 LCR Need Based on Category B			2009 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	48	135	183	177	0	**177**	177	0	**177**
North Coast / North Bay	217	728	945	766	0	**766**	766	0	**766**
Sierra	1012	768	1780	1453	226	**1679**	1617	703	**2320**
Stockton	276	265	541	491	34	**525**	541	185	**726**
Greater Bay	1111	5662	6773	4791	0	**4791**	4791	0	**4791**
Greater Fresno	510	2319	2829	2414	0	**2414**	2680	0	**2680**
Kern	646	31	677	208	0	**208**	417	5	**422**
LA Basin	3942	8222	12164	9728	0	**9728**	9728	0	**9728**
Big Creek/ Ventura	931	4201	5132	3178	0	**3178**	3178	0	**3178**
San Diego	292	2759	3051	3051	0	**3051**	3051	42	**3093**
Total	**8985**	**25090**	**34075**	**26257**	**260**	**26517**	**26946**	**935**	**27881**

2011 Local Capacity Needs

	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	48	166	214	148	8	**156**	148	37	**185**
North Coast / North Bay	217	728	945	900	0	**900**	907	6	**913**
Sierra	1012	768	1780	1263	0	**1263**	1649	450	**2099**
Stockton	276	265	541	348	0	**348**	427	258	**685**
Greater Bay	1120	5872	6992	5110	0	**5110**	5110	0	**5110**
Greater Fresno	510	2441	2951	2389	0	**2389**	2647	68	**2715**
Kern	646	31	677	212	0	**212**	411	1	**412**
LA Basin	3942	8581	12523	7000*	0	**7000***	10019	0	**10019**
Big Creek/ Ventura	931	4229	5160	3251	0	**3251**	4075	0	**4075**
San Diego	201	2781	2982	2267**	0	**2267****	2267**	57	**2324****
Total	**8903**	**25862**	**34765**	**22888**	**8**	**22896**	**27660**	**877**	**28537**

2013 Local Capacity Needs

	Qualifying Capacity			2013 LCR Need Based on Category B			2013 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	48	166	214	148	14	**162**	148	42	**190**
North Coast / North Bay	217	728	945	945	19	**964**	945	41	**986**
Sierra	1012	768	1780	1272	15	**1287**	1657	460	**2117**
Stockton	276	265	541	350	0	**350**	454	260	**714**
Greater Bay	1120	5872	6992	5344	0	**5344**	5344	0	**5344**
Greater Fresno	510	2441	2951	2461	0	**2461**	2644	113	**2757**
Kern	646	31	677	239	0	**239**	450	1	**451**
LA Basin	3942	11411	15353	8585	0	**8585**	8585	0	**8585**
Big Creek/ Ventura	931	4229	5160	2804	0	**2804**	3402	0	**3402**
San Diego	201	2781	2982	2418**	0	**2418****	2418**	71	**2489****
Total	**8903**	**28692**	**37595**	**24566**	**48**	**24614**	**26047**	**988**	**27035**

* - Potentially lower requirements – limit not reached (see detail description).
** - Potentially higher requirements combined with another area (see detail description).

Overall, the LCR trended is upward due to load growth except for the following areas: (1) Sierra, where the LCR was reduced mostly due to the installation of the Table Mountain-Rio Oso 230 kV Reconductor and Tower Upgrade, Palermo-Rio Oso 115 kV Reconductoring and the Rio Oso #1 and #2 230/115 kV Transformer Replacement; (2) Stockton, where the load trend is downward and due to the installation of the Tesla 115 kV Capacity Upgrade and the Tesla-Salado-Manteca 115 kV Reconductoring; (3) Kern where the load trend is downward; (4) LA Basin, where the LCR was reduced due to the installation of the Rancho Vista 500 kV Substation, Palo Verde-Devers #2 500 kV line, Green Path North (LADWP – 2013 only), Tehachapi Transmission Project (phased in) and the Vincent-Mira Loma 500 kV line (part of the Tehachapi - 2013 only); (5) the Big Creek/Ventura Area, where the LCR has increased first and then decreased due to the installation of the Sylmar-Pardee 230 kV Upgrade, Tehachapi Transmission Project (phased in), Green Path North (LADWP – 2013 only) and San Joaquin Cross Valley Loop (in last year's results all the major projects have been modeled in the 2010 as well as the 2012 case, this year they are only modeled in the 2013 case as such the results for 2011 have higher LCR requirements); and (6) San Diego where the LCR was reduced mostly due to the installation of the Sunrise 500 kV line (however potentially higher requirements exist - see detailed description). The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between the 2010-12 Long-Term LCR study and this study.

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

A. Objectives

As was the objective of all previous LCT Studies, the intent of the 2011-13 Long-Term LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

Inputs and Methodology

The CAISO used the same Inputs and Methodology as does agreed upon by interested parties previously incorporated into the 2009 LCR Study. The following table sets forth a summary of the approved inputs and methodology that have been used in the previous 2009 LCR Study as well as this 2011 and 2013 LCR Study:

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

Issue:	**HOW INCORPORATED INTO THIS LCR STUDY:**
<u>Input Assumptions:</u>	
• 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
<u>Methodology:</u>	
• **<u>Maximize Import Capability</u>**	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• **<u>QF/Nuclear/State/Federal Units</u>**	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCR Study.
• **<u>Maintaining Path Flows</u>**	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.
<u>Performance Criteria:</u>	
• **<u>Performance Level B & C, including incorporation of PTO operational solutions</u>**	This LCR Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, of the study year. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCR Study.
<u>Load Pocket:</u>	
• **<u>Fixed Boundary, including limited reference to published effectiveness factors</u>**	This LCR Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2009 as well as 2011 and 2013 LCR Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Area does can affect the reliability of other Balancing Areas. Consistent with the mandatory nature of the NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[1] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected bulk 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. For instance, one category could require that the grid operator not only ensure grid integrity is maintained under certain adverse system conditions, e.g., security, but also that all customers continue to receive electric supply

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[1] Pub. Utilities Code § 345

to meet demand, e.g., adequacy. In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

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

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

The N-1-1 vs N-2 terminology was introduced only as a 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 LCR Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC standards for the same NERC performance levels. These Performance Levels can be described as follows:

a. Performance Criteria- Category B

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

Category B system performance requires that all thermal and voltage limits must be within their "Applicable Rating," which, in this case, are the emergency ratings as generally determined by the PTO or facility owner. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met however there is no guarantee that facilities are returned to within normal ratings or to a state where it is safe to continue to operate the system in a reliable manner such that the next element out will not cause a violation of the Applicable Ratings.

b. Performance Criteria- Category C

The NERC Planning Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[2] All Category C requirements in this report refer to situations when in real time

[2] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the

(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

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

c. CAISO Statutory Obligation Regarding Safe Operation

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

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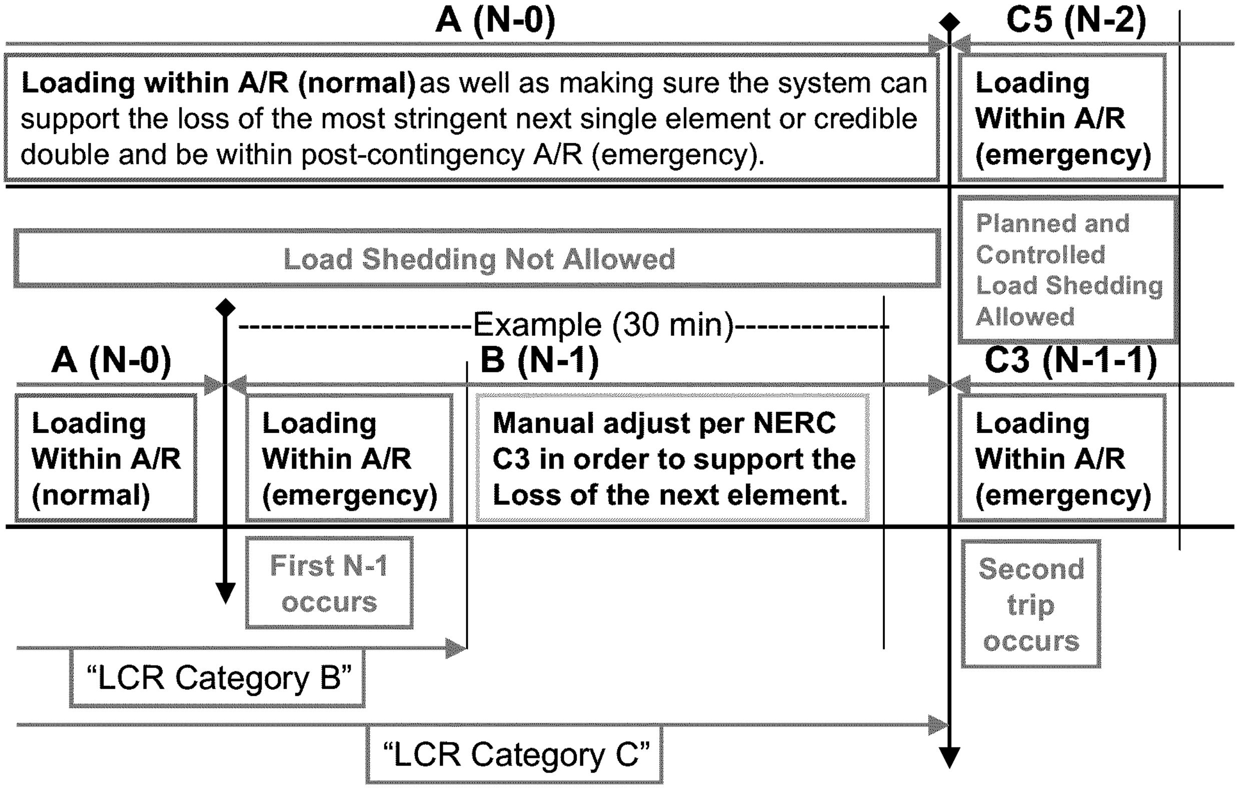
value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.



Definition of Terms

Applicable Rating:

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

Normal rating is to be used under normal conditions.

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

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

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

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 LSAG now appear to agree on the viability of dropping load as part of the system readjustment period – in order to protect for the next most limiting contingency. After a single contingency, it is understood that the system is in a Category B condition and the system should be planned based on the body of the criteria with no shedding of load regardless of whether it is done immediately or in 15-30 minute after the original contingency. Category C conditions only arrive after the second contingency has happened; at that point in time, shedding load is allowed in a planned and controlled manner.

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

Time allowed for manual readjustment:

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.

Planned load drop:

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.

Controlled load drop:

Is achieved with the use of a Special Protection Scheme.

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.

F. The Two Options Presented In This LCR Study

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

1. Option 1- Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[3]

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:

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

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Table 1: Criteria Comparison

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

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

A significant number of simulations were run to determine the most critical contingencies within each Local Capacity Area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all the contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 1. 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 over-lapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

3 Applicable Rating – Based on 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 as well as PTO levels. This relevant CEC forecast is then distributed across the entire system, down to the local area, division and substation level. PTO's 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; please refer to each PTO expansion plan for additional details.

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 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 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 then the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCR analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 16.1. 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. Locational 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 2: 2009 Local Capacity Requirements vs. Peak Load and Local Area Generation

	2009 Total LCR (MW)	Peak Load (1 in10) (MW)	2009 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2009 LCR as % of Total Area Generation
Humboldt	177	207	86%	183	97%
North Coast/North Bay	766	1596	48%	945	81%
Sierra	2320	2126	109%	1780	130%**
Stockton	726	1436	51%	541	134%**
Greater Bay	4791	10294	47%	6773	71%
Greater Fresno	2680	3381	79%	2829	95%
Kern	422	1316	32%	677	62%**
LA Basin	9728	19836	49%	12164	80%
Big Creek/Ventura	3178	4937	64%	5132	62%
San Diego	3093	5052	61%	3051	101%**
Total	**27,881**	**50,181***	**56%***	**34,075**	**82%**

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Table 3: 2011 Local Capacity Requirements 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	**185**	207	89%	214	86%**
North Coast/North Bay	**913**	1640	56%	945	97%**
Sierra	**2099**	2171	97%	1780	118%**
Stockton	**685**	1350	51%	541	127%**
Greater Bay	**5110**	10249	50%	6992	73%
Greater Fresno	**2715**	3432	79%	2951	92%**
Kern	**412**	1167	35%	677	61%**
LA Basin	**10019**	20633	49%	12523	80%
Big Creek/Ventura	**4075**	5226	78%	5160	79%
San Diego	**2324**	5206	45%	2982	78%**
Total	**28537**	**51281***	**56%***	**34765**	**82%**

Table 4: 2013 Local Capacity Requirements vs. Peak Load and Local Area Generation

	2013 Total LCR (MW)	Peak Load (1 in10) (MW)	2013 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2013 LCR as % of Total Area Generation
Humboldt	**190**	212	90%	214	89%**
North Coast/North Bay	**986**	1687	58%	945	104%**
Sierra	**2117**	2265	93%	1780	119%**
Stockton	**714**	1396	51%	541	132%**
Greater Bay	**5344**	10469	51%	6992	76%
Greater Fresno	**2757**	3526	78%	2951	93%**
Kern	**451**	1208	37%	677	67%**
LA Basin	**8585**	21113	41%	15353	56%
Big Creek/Ventura	**3402**	5729	59%	5160	66%
San Diego	**2489**	5357	46%	2982	83%**
Total	**27035**	**52962***	**51%***	**37595**	**72%**

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

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

Tables 2, 3 and 4 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 June 1 of either 2011 or 2013 have been included in this 2011-13 Long-Term 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, "YEAR LCR Requirement Based on Category B" identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B. The third column, "YEAR LCR Requirement Based on Category C with Operating Procedure", sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Results by Local Area

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

1. Humboldt Area

Area Definition

The transmission tie lines into the area include:

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

The substations that delineate the Humboldt Area are:

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

Total 2011 busload within the defined area: 200 MW with 7 MW of losses resulting in total load + losses of 207 MW. Total 2013 busload within the defined area: 206 MW with 6 MW of losses resulting in total load + losses of 212 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	NQC Comments	CAISO Tag
BRDGVL_7_BAKER				0.00		Not modeled	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.40	1		QF/Selfgen
FTSWRD_7_QFUNTS				0.60		Not modeled	QF/Selfgen
HUMBPP_1_MOBLE2	31154	HUMBOLDT	13.2	15.00	2	Retired - Not modeled	Market
HUMBPP_1_MOBLE3	31154	HUMBOLDT	13.2	15.00	1	Retired - Not modeled	Market
HUMBPP_7_UNIT 1	31170	HMBOLDT1	13.8	52.00	1	Retired - Not modeled	Market
HUMBPP_7_UNIT 2	31172	HMBOLDT2	13.8	53.00	1	Retired - Not modeled	Market
HUMBSB_1_QF				0.00		Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.17	1		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.16	2		QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.90	3		QF/Selfgen
WLLWCR_6_CEDRFL				0.00		Not modeled - Monthly NQC	QF/Selfgen

						- used August for LCR	
LAPAC_6_UNIT	31158	LP SAMOA	12.5	12.00	1	No NQC - historical data	QF/Selfgen
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	No NQC - historical data	Market
NA	31180	HUMB_G1	13.8	16.6	1	No NQC - Pmax	Market
NA	31180	HUMB_G1	13.8	16.6	2	No NQC - Pmax	Market
NA	31180	HUMB_G1	13.8	16.6	3	No NQC - Pmax	Market
NA	31180	HUMB_G1	13.8	16.6	4	No NQC - Pmax	Market
NA	31181	HUMB_G2	13.8	16.6	5	No NQC - Pmax	Market
NA	31181	HUMB_G2	13.8	16.6	6	No NQC - Pmax	Market
NA	31181	HUMB_G2	13.8	16.6	7	No NQC - Pmax	Market
NA	31182	HUMB_G3	13.8	16.6	8	No NQC - Pmax	Market
NA	31182	HUMB_G3	13.8	16.6	9	No NQC - Pmax	Market
NA	31182	HUMB_G3	13.8	16.6	10	No NQC - Pmax	Market

Major new projects modeled:

1. Humboldt Reactive Support
2. Humboldt Bay Repower

Critical Contingency Analysis Summary

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Humboldt 115/60 kV transformer #1 or #2 overlapping with an outage of one of the new gen-ties from Humboldt Bay Power Plant to units 5-7 (or 8-10). The local area limitation is potential overload on the remaining Humboldt 115/60 kV transformer #1 or #2. This contingency establishes a local capacity need of 185 MW (includes 48 MW of QF/Selfgen generation as well as 37 MW of deficiency) in 2011 and 190 MW (includes 48 MW of QF/Selfgen generation as well as 42 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Humboldt area is the outage of one of the new gen-ties from Humboldt Bay Power Plant to units 5-7 (or 8-10) with one CT out of service (from the remaining gen-tie), which could potentially overload the Humboldt 115/60 kV transformer #1 and #2. This contingency establishes a local capacity need of 156 MW (includes 48 MW of QF/Selfgen generation as well as 8 MW of deficiency) in 2011 and 162 MW (includes 48 MW of QF/Selfgen generation as well as 14 MW of deficiency) in 2013.

Effectiveness factors:

All units (in Humboldt's 60 kV system only) within this area are required therefore no effectiveness factor is needed. Resources connected to the 115 kV system do not help relieve the constraint.

Changes compared to last year's results:

The load forecast went up by 1 and 2 MW respectively or about 1%/year. The Humboldt Bay Repower along with Humboldt reactive support was modeled. The inclusion of the new 60 kV gen-tie line as a credible contingency accounts for the increase in LCR results by about 30 MW.

Humboldt Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	48	0	166	214

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[4]	148	8	156
Category C (Multiple)[5]	148	37	185

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[4]	148	14	162
Category C (Multiple)[5]	148	42	190

2. North Coast / North Bay Area

Area Definition

The North Coast/North Bay Area is composed of three sub-areas and the generation requirements within them.

[4] 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.

[5] 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 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 Kekawaka are in Garberville is out
4) Vaca Dixon is out Lakeville is in
5) Tulucay is in Vaca Dixon is out
6) Lakeville is in Sobrante is out
7) Ignacio is in Sobrante and Crocket are out

Total 2011 busload within the defined area: 1572 MW with 68 MW of losses resulting in total load + losses of 1640 MW. Total 2013 busload within the defined area: 1616 MW with 71 MW of losses resulting in total load + losses of 1687 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	7.34	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	7.34	2	Eagle Rock, Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	7.10	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	7.09	2	Fulton, Lakeville		Market
FULTON_1_QF				0.03		Fulton, Lakeville	Not modeled	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	64.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	52.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	61.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	49.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	56.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market

GEYS17_7_UNIT17	31422	GEYSER17	13.8	52.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	47.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	42.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	34.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	34.00	2	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYSRVL_7_WSPRNG				1.84		Fulton, Lakeville	Not modeled	QF/Selfgen
HIWAY_7_ACANYN				1.33		Lakeville	Not modeled	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	1.61	1	Eagle Rock, Fulton, Lakeville		QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.50	1	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.50	2	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.59	3	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
NAPA_2_UNIT				0.03		Lakeville	Not modeled	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	35.00	1	Lakeville		MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	32.00	1	Lakeville		MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	33.00	1	Fulton, Lakeville		MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	29.00	1	Fulton, Lakeville		MUNI
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville		Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville		Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville		Market
POTTER_7_VECINO				0.01		Eagle Rock, Fulton, Lakeville	Not modeled	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	33.58	1	Lakeville		QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	33.57	2	Lakeville		QF/Selfgen
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	41.00	1	Lakeville	Monthly NQC - used August for LCR	Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	7.70	1	Fulton, Lakeville		QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	11.75	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	11.74	2	Fulton, Lakeville		Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	55.00	1	Fulton, Lakeville	No NQC - Pmax	Market

Major new projects modeled:

1. Lakeville-Ignacio #2 230 kV line.

<u>Critical Contingency Analysis Summary</u>

Eagle Rock Sub-area

The most critical overlapping contingency is the outage of the Eagle Rock-Silverado-Fulton 115 kV line and the Cortina #4 230/115kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60kV. This limiting contingency establishes a local capacity need of 245 MW (includes 2 MW of QF generation as well as 6 MW of deficiency) in 2011 and 258 MW (includes 2 MW of QF generation as well as 19 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical overlapping contingency is the outage of Cortina #4 230/115kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60kV. This limiting contingency establishes a local capacity need of 113 MW in 2011 and 134 MW in 2013 (includes 2 MW of QF generation).

Effectiveness factors:

The units within the Eagle-Rock pocket have the same effectiveness to the above-mentioned constraint. Units outside this area are not effective.

Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Sonoma-Pueblo 115 kV line #1. This limiting contingency establishes a local capacity need of 437 MW in 2011 and 469 MW in 2013 (includes 17 MW of QF and 62 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the units required to meet the Eagle Rock pocket count towards the Fulton total requirement.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
38112	NCPA2GY2	1	25
38110	NCPA2GY1	1	25
31422	GEYSER17	1	25
31421	BOTTLERK	1	25
31420	GEYSER16	1	25
31418	GEYSER14	1	25
31414	GEYSER12	1	25
31404	WEST FOR	2	25
31404	WEST FOR	1	25
31402	BEAR CAN	1	25
31402	BEAR CAN	2	25
31435	GEO.ENGY	1	15
31435	GEO.ENGY	2	15
31412	GEYSER11	1	15
31408	GEYSER78	1	15
31408	GEYSER78	2	15
31406	GEYSR5-6	1	15
31406	GEYSR5-6	2	15

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Tulucay 230 kV line followed by Crockett-Sobrante 230 kV line or vice versa. The sub-area limitation is thermal overloading of the Vaca Dixon-Lakeville 230 kV. This limiting contingency establishes a local capacity need of 907 MW (includes 86 MW of QF generation) in 2011 and 986 MW (includes 86 MW of QF generation as well as 41 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this area. The local capacity need for Eagle Rock and Fulton sub-area can be counted toward fulfilling the need of Lakeville sub-area.

The single 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 local capacity need of 900 MW (includes 86 MW of QF generation) in 2011 and 964 MW (includes 86

MW of QF generation as well as 19 MW of deficiency) in 2013. The local capacity need for Eagle Rock and Fulton sub-area can be counted toward fulfilling the need of Lakeville sub-area.

Effectiveness factors:

The following table has units 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 up by 96 and 69 MW respectively or about 4-6%. The LCR requirements are increasing by 80 and 130 MW respectively. The higher increase in 2013 is due to fact the units less and less effective have to be dispatched in order to meet the need.

North Coast/North Bay Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	86	131	728	945

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[6]	900	0	900
Category C (Multiple)[7]	907	6	913

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[6]	945	19	964
Category C (Multiple)[7]	945	41	986

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out

[6] 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.

[7] 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) 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) Gold Hill is in Lodi Stig is out
12) Gold Hill is in Lake is out

Total 2011 busload within the defined area: 2059 MW with 112 MW of losses resulting in total load + losses of 2171 MW. Total 2013 busload within the defined area: 2155 MW with 110 MW of losses resulting in total load + losses of 2265 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		Market
BIOMAS_1_UNIT 1	32156	WOODLAND	9.1	21.30	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.58		Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled - Monthly NQC - used August for LCR	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain		Market
BOWMN_6_UNIT	32480	BOWMAN	9.1	1.25	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
BUCKCK_7_OAKFLT				1.30		South of Palermo, South of Table Mountain	Not modeled	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain		Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain		Market
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	165.80	1	South of Table Mountain		MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Monthly NQC - used August for LCR	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain		Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain		Market

DEERCR_6_UNIT 1	32474	DEER CRK	9.1	5.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	14.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	14.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		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	0.32	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	39.00	1	Drum-Rio Oso, South of Table Mountain		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	7.74	1	Bogue, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	39.55	2	Bogue, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	47.82	1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	11.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market

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HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
HIGGNS_7_QFUNTS				0.11		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	0.00	1	Colgate, South of Table Mountain	Monthly NQC - used August for LCR	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	34.88	1	Colgate, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	1.30	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	6.44	1	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	8.35	1	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	8.35	2	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	7.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled - Monthly NQC - used August for LCR	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain		Market
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain		Market

RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	56.00	1	South of Palermo, South of Table Mountain		Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain		Market
RIOOSO_1_QF				0.51		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	13.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	5.80	3	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.78	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.78	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	6.60	1	Drum-Rio Oso, South of Palermo, South of Rio Oso, South of Table Mountain		QF/Selfgen
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	21.28	1	Drum-Rio Oso, South of Palermo, South of Rio Oso, South of Table Mountain		QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
WISE_1_UNIT 1	32512	WISE	12	9.20	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
WISE_1_UNIT 2	32512	WISE	12	2.79	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	41.68	1	Pease, Drum-Rio Oso, South of Table Mountain		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	6.50	1	Colgate, South of Table Mountain	No NQC - historical data	MUNI
NA	31862	DEADWOOD	9.1	2.00	1	Drum-Rio Oso, South of Table Mountain	No NQC - historical data	MUNI
NA	32162	RIV.DLTA	9.11	3.10	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		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 - historical data	QF/Selfgen

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. South of Palermo 115 kV Reconductoring
3. Atlantic-Lincoln 115 kV Transmission Upgrade
4. Colgate 230/60 kV transformer reinforcement
5. Pease-Marysville #2 60 kV line
6. Gold Hill-Missouri Flat #1 and #2 115 kV line Reconductoring
7. Rio Oso #1 and #2 230/115 kV Transformer Replacement
8. Palermo #2 230/115 kV transformer derate

Critical Contingency Analysis Summary

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 a local capacity need of 1649 MW (includes 216 MW of QF and 796 MW of Muni generation) in 2011 and 1657 MW (includes 216 MW of QF and 796 MW of Muni generation) in 2013 as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Table Mountain-Rio Oso 230 kV line with one of the Colgate Units out of service. The area limitation is thermal overloading of the Palermo #2 230/115 kV transformer. This limiting contingency establishes a local capacity need of 1263 MW (includes 216 MW of QF and 796 MW of Muni generation) in 2011 and 1272 MW (includes 216 MW of QF and 796 MW of Muni generation) in 2013.

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
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

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV transmission upgrade, Colgate 230/60 kV transformer reinforcement and Pease-Marysville #2 60 kV line projects.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with one of the Greenleaf #2 (or Yuba City) units out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a local capacity need of 128 MW (includes 90 MW of QF generation) in 2011 and 130 MW (includes 90 MW of QF generation) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area. It is assumed that Oliverhurst is normally served from Palermo-Bogue 115 kV line and East Marysville is normally served from Palermo-East Nicolaus 115 kV line not from Pease-Rio Oso 115 kV line.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) are needed therefore no effectiveness factor is required.

Bogue Sub-area

No requirements due to the addition of the South of Palermo 115 kV reconductoring project.

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 Palermo #2 230/115 kV transformer, Pease-Rio Oso, Bogue-Rio Oso and East Nicolaus-Rio Oso 115 kV lines. This limiting contingency establishes a local capacity need of 1792 MW (includes 610 MW of QF and Muni generation as well as 450 MW of deficiency) in 2011 and 1804 MW (includes 610 MW of QF and Muni generation as well as 460 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area. It is assumed that Oliverhurst is normally served from Palermo-Bogue 115 kV line and East Marysville is normally served from Palermo-East Nicolaus 115 kV not from Pease-Rio Oso 115 kV line.

The single most critical 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 Palermo-Pease 115 kV line. This limiting contingency establishes a local capacity need of 667 MW (includes 454 MW of QF and Muni generation) in 2011 and 669 MW (includes 454 MW of QF and Muni generation) in 2013.

Effectiveness factors:

All units within this sub-area 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 local capacity need of 108 MW (includes 0 MW of QF and Muni generation as well as 79 MW of deficiency) in 2011 and 132 MW (includes 0 MW of QF and Muni generation as well as 103 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Placer Sub-area

The most critical contingency is the loss of the Drum-Higgins 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a local capacity need of 130 MW (includes 0 MW of QF and Muni generation as well as 106 MW of deficiency) in 2011 and 144 MW (includes 0 MW of QF and Muni generation as well as 120 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Drum-Higgins 115 kV line with the Halsey unit out of service. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a local capacity need of 24 MW (includes 0 MW of QF and Muni generation) in 2011 and 39 MW (includes 0 MW of QF and Muni generation as well as 15 MW of deficiency) in 2013.

Effectiveness factors:

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

Drum-Rio Oso Sub-area

No requirements due to the Rio Oso #1 and #2 230/115 kV transformers replacement project.

South of Rio Oso Sub-area

The most critical contingency is the loss of the DCTL Rio Oso-Gold Hill & Rio Oso-Atlantic 230 kV lines. The area limitation is thermal overloading of the Rio Oso-Lincoln and Lincoln-Pleasant Grove 115 kV lines. This limiting contingency establishes a local capacity need of 590 MW (includes 291 MW of QF and Muni generation as well as 150 MW of deficiency) in 2011 and 610 MW (includes 291 MW of QF and Muni generation as well as 170 MW of deficiency) in 2013 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 local capacity need of 342 MW (includes 291 MW of QF and Muni generation) in 2011 and 426 MW (includes 291 MW of QF and Muni generation) in 2013.

Effectiveness factors:

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

Changes compared to last year's results:

The load forecast went up by 64 and 53 MW respectively or about 2.5%. Overall the LCR needs are steady; the load is driving higher needs but the transmission projects are decreasing them. The slightly higher deficiency is driven by the Palermo #2 230/115 kV transformer derate.

Sierra Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	216	796	768	1780

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[8]	1263	0	1263
Category C (Multiple)[9]	1649	450	2099

[8] 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.

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[8]	1272	15	1287
Category C (Multiple)[9]	1657	460	2117

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 Stagg Sub-area are:

1) Tesla – Stagg 230 kV Line

[9] 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.

2) Tesla – Eight Mile Road 230 kV Line
3) Gold Hill – Eight Mile Road 230 kV Line
4) Gold Hill - Lodi Stig 230 kV Line

The substations that delineate the Stagg Sub-area are:

1) Tesla is out Stagg is in
2) Tesla is out Eight Mile Road is in
3) Gold Hill is out Eight Mile Road is in
4) Gold Hill is out Lodi Stigg is in

Total 2011 busload within the defined area: 1327 MW with 23 MW of losses resulting in total load + losses of 1350 MW. Total 2013 busload within the defined area: 1372 MW with 24 MW of losses resulting in total load + losses of 1396 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	Monthly NQC - used August for LCR	MUNI
CURIS_1_QF				0.67		Tesla-Bellota	Not modeled	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford	No NQC - historical data	MUNI
PHOENX_1_UNIT				1.45		Tesla-Bellota	Not modeled - Monthly NQC - used August for LCR	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	8.16	1	Tesla-Bellota		MUNI
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	6.70	1	Tesla-Bellota		Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota		Market
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	Stagg		MUNI
STNRES_1_UNIT	34056	STNSLSRP	13.8	16.72	1	Tesla-Bellota		QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	47.04	1	Tesla-Bellota		QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	16.69	1	Tesla-Bellota		QF/Selfgen
VLYHOM_7_SSJID				1.18		Tesla-Bellota	Not modeled	QF/Selfgen
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	1	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	2	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	3	Tesla-Bellota	No NQC - historical data	MUNI
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - historical data	QF/Selfgen
SPIFBD_1_PL1X2	33917	FBERBORD	115	3.20	1	Tesla-Bellota	No NQC - historical data	QF/Selfgen

Major new projects modeled:

1. Tesla 115 kV Capacity Increase
2. Reconductor Tesla-Salado-Manteca 115 kV
3. Stagg #1 and #2 230/60 kV transformer replacement

<u>Critical Contingency Analysis Summary</u>

Stockton overall

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 579 MW (includes 201 MW of QF and Muni generation as well as 202 MW of deficiency) in 2011 and 581 MW (includes 201 MW of QF and Muni generation as well as 202 MW of deficiency) in 2013 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 502 MW (includes 201 MW of QF and Muni generation as well as 202 MW of deficiency) in 2011 and 502 MW (includes 201 MW of QF and Muni generation as well as 202 MW of deficiency) in 2013.

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 local capacity need of 377 MW (includes 201 MW of QF and Muni generation) in 2011 and 379 MW (includes 201 MW of QF and Muni generation) in 2013.

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 324 MW (includes 201 MW of QF and Muni generation) in 2011 and 325 MW (includes 201 MW of QF and Muni generation) in 2013.

Effectiveness factors:

All units within this sub-area are needed for the most limiting contingency 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 Lodi-Industrial 60 kV as well as Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a local capacity need of 81 MW (including 25 MW of QF and Muni as well as a deficiency of 56 MW) in 2011 and 83 MW (including 25 MW of QF and Muni as well as a deficiency of 58 MW) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency for the Lockeford pocket is the loss of Lockeford-Lodi #2 60 kV line and the loss of the Lodi CT with possible overload of the Lockeford-Industrial 60 kV. This single contingency establishes a local capacity need of 24 MW (includes 25 MW of QF and Muni generation) in 2011 and 25 MW (includes 25 MW of QF and Muni generation) in 2013.

Effectiveness factors:

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

Stagg Sub-area

The outage of the Tesla-Stagg 230 kV line and Tesla-Eight Mile 230 kV line causes low voltages at Stagg, Eight Mile Road and Lodi Stig 230 kV busses. Post-contingency steady-state voltages at these three busses are less than 0.90 pu. Lodi Stig generating unit is needed to support voltage at these three 230 kV busses. This limiting contingency establishes a local capacity need of 25 MW (includes 50 MW of Muni generation) in 2011 and 50 MW (includes 50 MW of Muni generation) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The only unit within this sub-area (Lodi Stig) is needed therefore no effectiveness factor is required.

Changes compared to last year's results:

Overall the load forecast went down by 56 and 61 MW respectively or about 4%. A new project: reconductor Tesla-Salado-Manteca 115 kV was modeled in the base cases. Overall the total LCR has decreased by about 90 and 166 MW respectively because of load decrease, the new transmission project and the fact that the big deficiencies in the Stagg area (were) are driven by voltage problems (a non-liner function).

Stockton Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	88	188	265	541

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[10]	348	0	348
Category C (Multiple)[11]	427	258	685

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[10]	350	0	350
Category C (Multiple)[11]	454	260	714

[10] 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.

[11] 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. Greater Bay Area

Area Definition

The transmission tie lines into the Greater Bay Area are:

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

The substations that delineate the Greater Bay Area are:

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

Total 2011 busload within the defined area: 9971 MW with 278 MW of losses resulting in total load + losses of 10249 MW. Total 2013 busload within the defined area: 10182 MW with 287 MW of losses resulting in total load + losses of 10469 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.00	1	Oakland		MUNI
BLHVN_7_MENLOP				1.57		None	Not modeled	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	78.64	1	None	Monthly NQC - used August for LCR	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	35.24	1	None	Monthly NQC - used August for LCR	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	26.56	1	San Jose		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.47	12.64	1	None		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.47	12.64	2	None		QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	337.00	1	None		Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	337.00	1	None		Market
CONTAN_1_UNIT	36856	CCA100	13.8	16.26	1	San Jose		QF/Selfgen
CROKET_7_UNIT	32900	CRCKTCOG	18	240.00	1	Pittsburg		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	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DOWCHM_1_UNITS	33161	DOWCHEM1	13.8	6.63	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33162	DOWCHEM2	13.8	8.76	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33163	DOWCHEM3	13.8	8.76	1	Pittsburg		QF/Selfgen
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
FLOWD2_2_UNIT 1	35318	FLOWDPTR	9.11	9.94	1	None	Monthly NQC - used August for LCR	Wind
GILROY_1_UNIT	35850	GLRY COG	13.8	66.00	1	Llagas	Monthly NQC - used August for LCR	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	34.00	2	Llagas	Monthly NQC - used August for LCR	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Monthly NQC - used August for LCR	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Monthly NQC - used August for LCR	Market

GILRPP_1_PL3X4	35853	GROYPKR3	13.8	45.00	1	Llagas	Monthly NQC - used August for LCR	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	26.48	1	None		QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	19.42	1	Pittsburg		QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.90	1	Pittsburg		QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	19.37	1	Pittsburg		QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	19.09	1	Pittsburg		QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	18.97	1	Pittsburg		QF/Selfgen
HICKS_7_GUADLP				1.91		None	Not modeled	QF/Selfgen
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	4.50	1	None	Monthly NQC - used August for LCR	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	None	Monthly NQC - used August for LCR	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	None	Monthly NQC - used August for LCR	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	None	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Monthly NQC - used August for LCR	Market
MARKHM_1_CATLST	35863	CATALYST	9.11	2.00	1	San Jose		QF/Selfgen
MEDOLN_7_CHEVCP				0.91		Pittsburg	Not modeled	QF/Selfgen
METCLF_1_QF				0.37		None	Not modeled	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	None	Monthly NQC - used August for LCR	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	None	Monthly NQC - used August for LCR	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	None	Monthly NQC - used August for LCR	Market
MISSIX_1_QF				0.02		San Francisco	Not modeled	QF/Selfgen
MLPTAS_7_QFUNTS				0.62		San Jose	Not modeled	QF/Selfgen
MNTAGU_7_NEWBYI				3.42		None	Not modeled	QF/Selfgen
NEWARK_1_QF				0.00		None	Not modeled	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				1.22		Oakland	Not modeled	MUNI
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
POTRPP_7_UNIT 3	33252	POTRERO3	20	206.00	1	San Francisco		Market

POTRPP_7_UNIT 4	33253	POTRERO4	13.8	52.00	1	San Francisco		Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	52.00	1	San Francisco		Market
POTRPP_7_UNIT 6	33255	POTRERO6	13.8	52.00	1	San Francisco		Market
RICHMN_7_BAYENV				2.00		None	Not modeled	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	None	Monthly NQC - used August for LCR	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	1.62	1	None	Monthly NQC - used August for LCR	Wind
SJOSEA_7_SJCONV				0.00		None	Not modeled	QF/Selfgen
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.89	1	None		QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.03	1	None		QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.09	1	Pittsburg		QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.09	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	5.97	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	5.97	2	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	5.97	3	Pittsburg		QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	20.00	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.40	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.40	2	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.39	3	Pittsburg		QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	27.25	1	None		QF/Selfgen
USWNDR_2_UNITS	32168	EXNCO	9.11	12.62	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.88	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.88	2	None	Monthly NQC - used August for LCR	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	9.76	1	None	Monthly NQC - used August for LCR	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	1.91	1	None	Monthly NQC - used August for LCR	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	3.40	1	None	Monthly NQC - used August for LCR	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18.0	200.00	1	None	No NQC - Pmax	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18.0	195.00	1	None	No NQC - Pmax	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18.0	195.00	1	None	No NQC - Pmax	Market
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - historical data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.47	4.40	1	Pittsburg	No NQC - historical data	QF/Selfgen
New unit	32177	SHILO	34.5	35.24	2	None	No NQC - estimated data	Wind
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	1	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	2	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	3	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	4	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	5	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	6	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	7	None	No NQC - Pmax	Market
SHELRF_1_UNITS	33141	SHELL 1	12.47	20.00	1	Pittsburg	No NQC - historical data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.47	40.00	1	Pittsburg	No NQC - historical data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.47	40.00	1	Pittsburg	No NQC - historical data	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	20.00	1	None	No NQC - historical data	Wind
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	2.10	1	San Jose	No NQC - historical data	QF/Selfgen
NA	32171	HIGHWND3	34.5	9	1	None	No NQC - Estimated	Market

NA	33283	CCSFCT3	13.8	53	1	San Francisco	No NQC - Pmax	Market
NA	33282	CCSFCT2	13.8	53	1	San Francisco	No NQC - Pmax	Market
NA	33281	CCSFCT1	13.8	53	1	San Francisco	No NQC - Pmax	Market
NA	33467	SFAERP	13.8	50.5	1	San Francisco	No NQC - Pmax	Market

Major new projects modeled:

1. Oakland New 115 kV Cable
2. Moraga #1 and #2 230/115 kV transformer replacement
3. Trans Bay 230 kV Cable
4. San Francisco 115 kV Re-cabling
5. HP #4 115 kV Cable
6. Tesla-Pittsburg 230 kV Reconductoring
7. Metcalf-Moss Landing 230 kV Reinforcement
8. Metcalf-Monta Vista 230 kV Nr. 1 and 2 Reconductoring
9. Monta Vista 115/60 kV Transformer
10. Vaca Dixon 500/230 kV Transformer
11. Metcalf-El Patio 115 kV Reconductoring
12. Vaca Dixon-Birds Landing 230 kV Reinforcement
13. Contra Costa-Las Positas 230 kV Reconductoring
14. Newark-Ravenswood 230 kV Reconductoring
15. Gateway Power Plant

Critical Contingency Analysis Summary

San Francisco Sub-area

Per the CAISO Revised Action Plan for SF, all Potrero units (360 MW) will continued to be required until completion of the plan as it is presently described.

The most critical contingency is an outage of the TransBay cable and the A-H-W #1 115 kV cable. The limiting contingency is an overload of the A-H-W #2 115 kV Cable. This limiting contingency establishes a local capacity need of 10 MW and 15 MW (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area in 2011 and 2013, respectively.

Effectiveness factors:

The 3 CCSF CT's and Potrero units (if available) have the same effectiveness factor.

Oakland Sub-area

The critical contingency for the Oakland pocket is the loss of C-X #2 and C-X #3 115 kV cables. The area limitation is thermal overloading of the Moraga-Claremont #1 & #2 115 kV lines above their emergency rating. This limiting contingency establishes a local capacity need of 123 MW (includes 49 MW of Muni generation) in 2011 and 133 MW (includes 49 MW of Muni generation) in 2013 as minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor. Units outside of this sub-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 low voltage at Morgan Hill substation. This limiting contingency establishes a local capacity need of 120 MW in 2011 and 150 MW in 2013 respectively (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

San Jose Sub-area

The most critical contingencies in the San Jose area are a combined loss of Metcalf-El Patio #1 115 kV and the Metcalf-Evergreen #1 115 kV lines. The limiting element is the Metcalf-Evergreen #2 115kV line. This limiting contingency establishes a local capacity need of 290 MW in 2011 and 300 MW in 2013 (includes 48 MW of QF and 202 MW of Muni generation) as 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 Sub-area

This sub-area has no local capacity need due to reconductoring of the Tesla-Pittsburg #1 and #2 230 kV lines.

Bay Area overall

The most critical contingency is the loss of the Tesla-Metcalf 500 kV followed by Delta Energy Center or vice versa. The area limitation is reactive margin. This limiting contingency establishes a local capacity need of 5110 MW in 2011 and 5344 MW in 2013 (includes 641 MW of QF, 215 MW of Wind and 255 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area (with both Contra Costa 4 & 5 off-line).

The second most critical contingency is the loss of the Tesla-Metcalf 500kV line followed by Tesla #2 500/230kV transformer. The limiting element is the Tesla #6 500/230kV transformer. This limiting contingency establishes a local capacity need of 4772 MW in 2011 and 4902 MW for 2013 (includes 641 MW of QF, 215 MW of Wind and 255 MW of Muni generation). (This requirement only includes units in the Greater Bay Area, assuming all effective units in Stockton are at their historical output levels and not included in the requirement total.)

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors – Bay Area at:

http://www.caiso.com/docs/2004/11/01/2004110116234011719.pdf

Changes compared to last year's results:

Overall the load forecast went up by 179 and 163 MW respectively or about 1.5%. A few new small resources and Gateway Power Plant were to be installed and a significant number of transmission projects within the Bay Area are scheduled to become operational in this time frame. Reactive Margin is a non-linear function and the overall effect is that LCR has decreased by about 115 and 108 MW respectively.

Bay Area Overall Requirements:

	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	224	641	255	5872	6992

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[12]	5110	0	5110
Category C (Multiple)[13]	5110	0	5110

[12] 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.

[13] 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.

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [12]	5344	0	5344
Category C (Multiple) [13]	5344	0	5344

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

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

The substations that delineate the Greater Fresno area are:

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

Total 2011 busload within the defined area: 3308 MW with 124 MW of losses resulting in total load + losses of 3432 MW. Total 2013 busload within the defined area: 3403 MW with 123 MW of losses resulting in total load + losses of 3526 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	21.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	42.62	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.38	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00	1	Wilson, Herndon		Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon		Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon		Market
BORDEN_2_QF	30805	BORDEN	230	1.01		Wilson	Not modeled	QF/Selfgen
BULLRD_7_SAGNES				0.00		Wilson	Not modeled	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.47	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	9.24	1	Wilson		QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.38	2	Wilson		QF/Selfgen
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNEAGN	9.11	35.96	1	Wilson		QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	1.53		Wilson	Not modeled	MUNI
CRNEVL_6_CRNVA				0.71		Wilson	Not modeled - Monthly NQC - used August for LCR	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson		Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson		Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	10.54	1	Wilson, Herndon		Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Monthly NQC - used August for LCR	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	7.58	2	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	4.05	3	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.07	4	Wilson		QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	38.00	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	24.02	1	Wilson, Henrietta		QF/Selfgen
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Monthly NQC - used August for LCR	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Monthly NQC - used August for LCR	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson		Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	2	Wilson		Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson		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	4.04	1	Wilson	Monthly NQC - used August for LCR	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	7.00	1	Wilson, Merced		QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00	1	Wilson, Herndon		Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50	2	Wilson, Herndon		Market
KERKH1_7_UNIT 3	34344	KERCKHOF	6.6	12.80	3	Wilson, Herndon		Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon		Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	29.77	1	Wilson, Herndon		QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon		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				0.75		Wilson, Herndon	Not modeled	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	5.04	1	Wilson	Monthly NQC - used August for LCR	MUNI
MENBIO_6_UNIT	34334	BIO PWR	9.11	21.19	1	Wilson		QF/Selfgen
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.20	1	Wilson	Monthly NQC - used August for LCR	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	75.00	1	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	75.00	2	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	75.00	3	Wilson, Herndon		MUNI
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	36.51	1	Wilson		QF/Selfgen
STOREY_7_MDRCHW				1.04		Wilson	Not modeled	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	21.77	1	Wilson, Herndon		QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.60	1	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.60	2	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.60	3	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.60	4	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	0.00	5	Wilson		Market
WRGHTP_7_AMENGY				0.66		Wilson	Not modeled	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	12.50	1	Wilson, Herndon	No NQC - Pmax	Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	12.50	1	Wilson	No NQC - Pmax	Market
NA	34485	FRESNOWW	12.5	9.00	1	Wilson	No NQC - historical data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - historical data	MUNI
(Starwood Power Midway LLC, Unit #1)	34328	STARGT1	13.8	60.9	1	Wilson	New gen	Market
(Starwood Power Midway LLC, Unit #2)	34329	STARGT2	13.8	60.9	2	Wilson	New gen	Market

Major new projects modeled:

None.

Critical Contingency Analysis Summary

Wilson Sub-area

The most critical contingency for the Wilson sub-area is the loss of the Wilson - Melones 230 kV line overlapped with the loss of one Helms Unit, which would thermally overload the Warnerville - Wilson 230 kV line. This limiting contingency establishes a local capacity need of 2179 MW (includes 216 MW of QF and 294 MW of Muni generation) in 2011 and 2260 MW (includes 216 MW of QF and 294 MW of Muni generation) in 2013 as the 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%
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 for the Herndon sub-area is the loss of the Herndon 230/115 kV bank 1 overlapped with the loss of Kerckhoff II unit, which would thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a local capacity need of 1222 MW (includes 52 MW of QF and 225 MW of Muni generation, as well as 68 MW of deficiency) in 2011 and 1267 MW (includes 52 MW of QF and 225 MW of Muni generation as well as 113 MW of deficiency) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Herndon sub-area is the loss of the Herndon #1 230/115 kV bank, which could thermally overload the parallel Herndon #2 230/115 kV bank. This limiting contingency establishes a local capacity need of 1068 MW (includes 52 MW of QF and 225 MW of Muni generation) in 2011 and 1113 MW (includes 52 MW of QF and 225 MW of Muni generation) in 2013.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34308	KERCHHOF	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%
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%

McCall Sub-area

McCall #1 230/115 kV transformer bank was replaced in 2008. As a result the LCR need for the McCall sub-area has been eliminated.

Henrietta Sub-area

The most critical contingency for the Henrietta sub-area is the loss of the Henrietta 230/70 kV transformer bank #4 with Henrietta-GWF Henrietta 70 kV line out of service, which would thermally overload the Henrietta 230/70 kV transformer bank #2. This combined contingency establishes a local capacity need of 30 MW (includes 24 MW of QF generation) in 2011 and 35 MW (includes 24 MW of QF generation) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Merced Sub-area

The Atwater SPS was installed in 2008. As a result the LCR need for the Merced sub-area has been eliminated.

Additional helpful effectiveness factors for Fresno area:

Please read procedure T-129Z effectiveness factors - Fresno Area at: http://www.caiso.com/docs/2005/07/13/2005071314483315210.pdf

Changes compared to last year's results:

Overall the load forecast went up by 120 MW and 135 MW respectively or about 3%. The definition for the area has changed slightly to better account for the normal open point between Corcoran and Smyrna as well as the rearrangement at the Panoche substation due to new generation connections. Another significant factor in the increase in LCR is changes in the Path 15 flow from 2100 MW S-N to 1275 MW N-S. Based on historical data at the time of system peak and/or Fresno peak there is no consistent Path 15 flow. The CAISO became aware of the fact that Path 15 flows have a rather significant effect on the Fresno LCR during this last year. As such, the Path 15 flow chosen for the Fresno LCR base case assures the CAISO that if the LCR for Fresno are procured the CAISO can sustain any Path 15 flow during system and/or Fresno peak. This assumption has been implemented during this LCT Study and was included in the CAISO LCR Manual. The total overall effect is that LCR has increased by 370-500 MW or about 15%.

Fresno Area Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	216	294	2441	2951

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [14]	2386	0	2386
Category C (Multiple) [15]	2647	68	2715

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [14]	2461	0	2461
Category C (Multiple) [15]	2644	113	2757

7. Kern Area

Area Definition

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 & 3A
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 & 2a
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 is out Kern PP 115 kV is in
3) Kern PP 230 is out Kern PP 115 kV is in
4) Kern PP 230 is out Kern PP 115 kV is in
5) Midway 230 is out Midway 115 is in
6) Midway 230 is out Midway 115 is in
7) Midway 230 is out Midway 115 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-Weedpatch 60 kV line
3) Wheeler Ridge-San Bernard 60 kV line

The substations that delineate the Weedpatch sub-area are:

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[14] 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.
[15] 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) Wheeler Ridge is out Tejon is in
2) Wheeler Ridge is out Weedpatch is in
3) Wheeler Ridge is out San Bernard is in

Total 2011 busload within the defined area: 1154 MW with 13 MW of losses resulting in total load + losses of 1167 MW. Total 2013 busload within the defined area: 1195 MW with 13 MW of losses resulting in total load + losses of 1208 MW.

Total units and qualifying capacity available in this Kern PP sub-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	42.48	1	Kern PP		QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	43.20	1	Kern PP		QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	40.91	1	Kern PP		QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	0.87	1	Kern PP		QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	7.25	1	Kern PP		QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	29.49	1	Kern PP		QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	4.88	1	Kern PP		QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	47.00	1	Kern PP		QF/Selfgen
FELLOW_7_QFUNTS				4.12		Kern PP	Not modeled	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.10	1	Kern PP		QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	44.32	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.44	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.45	2	Kern PP		QF/Selfgen
KRNCNY_6_UNIT	35018	KERNCNYN	9.11	9.22	1	Weedpatch	Monthly NQC - used August for LCR	Market
KRNOIL_7_TEXEXP				11.95		Kern PP	Not Modeled	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	40.58	1	Kern PP		QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	34.46	1	Kern PP		QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	21.80	1	Kern PP		Market
MIDWAY_1_QF				0.03		Kern PP	Not modeled	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	44.99	1	Kern PP		QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	52.47	1	Kern PP		QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	1	Kern PP		QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	2	Kern PP		QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	38.87	1	Kern PP		QF/Selfgen
RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.11	6.39	1	Weedpatch		QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	44.43	1	Kern PP		QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	8.93	1	Kern PP		QF/Selfgen
TEMBLR_7_WELLPT				0.57		Kern PP	Not modeled	QF/Selfgen

TXMCKT_6_UNIT				1.71		Kern PP	Not modeled	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.00	1	Kern PP		QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.00	2	Kern PP		QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.82	1	Kern PP		QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	32.86	1	Kern PP		QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	18.14	1	Kern PP		QF/Selfgen
NA	35056	TX-LOSTH	4.16	9.00	1	Kern PP	No NQC - historical data	QF/Selfgen

Major new projects modeled:

None.

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency for the Kern PP sub-area is the outage of the Kern PP #5 230/115 kV transformer bank and the Kern PP – Kern Front 115 kV line, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a local capacity need of 395 MW in 2011 and 434 MW in 2013 (includes 639 MW 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 #5 230/115 kV transformer bank, which could thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a local capacity need of 212 MW in 2011 and 239 MW in 2013 (includes 639 MW of QF generation).

Effectiveness factors:

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

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 and the Wheeler Ridge – Tejon 70 kV line, which could overload the Wheeler Ridge – Weedpatch 70 kV line and cause low voltage problem in the local 70 kV system. This limiting contingency establishes a local capacity need of 17 MW (includes 6 MW of QF generation and 1 MW of deficiency) for both 2011 and 2013 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.

Changes compared to last year's results:

Overall the load forecast went down by 148 MW and 141 MW respectively or about 13%. As a result the LCR has decreased by 7-11% MW.

Kern Area Overall Requirements:

	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	646	31	677

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [16]	212	0	212
Category C (Multiple) [17]	411	1	412

[16] 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.

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [16]	239	0	239
Category C (Multiple) [17]	450	1	451

8. LA Basin Area

Area Definition

The 2011 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 #1 230 kV Line
8) Antelope - Mesa Cal #1 230 kV Line
9) Vincent - Rio Hondo #1 & #2 230 kV Lines
10) Eagle Rock - Pardee #1 230 kV Line
11) Devers - Palo Verde 500 kV Line
12) Devers - Harquahala 500 kV Line
13) Devers - Coachelv # 1 230 kV Line
14) Mirage - Ramon # 1 230 kV Line
15) Mirage - Julian Hinds 230 kV Line

The 2011 substations that delineate the LA Basin Area are:

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) Mesa Cal is in Antelope is out
9) Rio Hondo is in Vincent is out
10) Eagle Rock is in Pardee is out
11) Devers is in Palo Verde is out
12) Devers is in Harquahala is out
13) Devers is in Coachelv is out

[17] 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.

14) Mirage is in Ramon is out
15) Mirage is in Julian Hinds is out

The 2013 transmission tie lines into the LA Basin Area in 2013 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 #1 & #2 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee #1 230 kV Line
10) Devers - Palo Verde 500 kV Line
11) Devers - Harquahala 500 kV Line
12) Devers – Devers LA 500kV Line
13) Mirage - Coachelv # 1 230 kV Line
14) Mirage - Ramon # 1 230 kV Line
15) Mirage - Julian Hinds 230 kV Line

The 2013 substations that delineate the LA Basin Area are:

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) Devers is in Harquahala is out
12) Devers is in Devers LA is out
13) Mirage is in Coachelv is out
14) Mirage is in Ramon is out
15) Mirage is in Julian Hinds is out

Total 2011 busload within the defined area is 19,964 MW with 422 MW of losses and 22 MW of pumps resulting in total load + losses + pumps of 20,408 MW. Total 2013 busload within the defined area is 20,633 MW with 458 MW of losses and 22 MW of pumps resulting in total load + losses + pumps of 21,113 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	46.00	1	Western		MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	64.88	1	Western		QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	64.88	2	Western		QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	64.88	3	Western		QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	64.88	4	Western		QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	32.45	5	Western		QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	32.45	6	Western		QF/Selfgen
BADLND_7_PL1X2				1.20		Eastern	Not modeled	Market
BARRE_2_QF	24016	BARRE	230			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_Y_WINTCV	25634	BUCKWIND	115	1.32	W5	Eastern		Wind
CABZON_1_WINDA1	28280	CABAZON	33	13.23	1	Eastern	Monthly NQC - used August for LCR	Wind
CENTER_2_QF	24203	CENTER S	66	25.38		Western	Not Modeled	QF/Selfgen
CENTER_6_PEAKER	28308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4				34.00		Eastern	Not Modeled	Market
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.57	1	Western		QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.58	2	Western		QF/Selfgen
CHINO_2_QF	24024	CHINO	66	11.55		Western	Not modeled	QF/Selfgen
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.62	1	Western		QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	39.95	1	Western		QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.90		Western	Not modeled	Market
COLTON_6_AGUAM1				43.00		Eastern	Not Modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00	1	Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00	2	Eastern	Not modeled	MUNI
DEVERS_1_QF	24815	GARNET	115	14.13	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	4.26	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	3.79	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	3.24	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	6.23	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.86	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	1.19	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	1.25	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	1.70	W1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	7.58	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	5.11	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	5.68	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen

DEVERS_1_QF	25645	VENWIND	115	3.20	EU	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	3.66	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	4.83	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	5.30	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.57	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	21.00		Eastern	Not modeled	QF/Selfgen
DREWS_6_PL1X4				34.00		Eastern	Not modeled	Market
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.66	3	Eastern		MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.66	4	Eastern		MUNI
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.74	1	Eastern		MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.74	2	Eastern		MUNI
ELLIS_2_QF	24197	ELLIS	66	0.38		Western	Not modeled	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.82		Eastern	Not modeled	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	17.74		Eastern	Not modeled	QF/Selfgen
ETIWND_6_GRPLND	28305	ETWPKGEN	13.8	42.53	1	Eastern		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	19.94	1	Eastern		Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	2.10		Eastern	Not modeled	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	1.25	G1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.45	G2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.90	G3	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.45	PC	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
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	1	Western	Not modeled	MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42	1	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	29.00	1	Western		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	27.40	1	Western		QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.80	1	Western		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western		Market
HNTGBH_7_Unit 3	24167	HUNT3 G	13.8	225.00	3	Western		Market
HNTGBH_7_Unit 4	24168	HUNT4 G	13.8	227.00	4	Western		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
JOHANN_6_QFA1	24072	JOHANNA	230	0.01		Western	Not Modeled	QF/Selfgen
LACIEN_2_QF	24208	LCIENEGA	66	0.00		Western	Not modeled	QF/Selfgen
LAFRES_6_QF	24073	LA FRESA	66	4.06		Western	Not modeled	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.89		Western	Not modeled	QF/Selfgen

LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	46.77	1	Western		QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.68		Western	Not modeled	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.50		Western	Not modeled	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	38.59	1	Eastern		QF/Selfgen
MIRLOM_6_GRPLND	28307	MRLPKGEN	13.8	43.18	1	Eastern		Market
MTWIND_1_UNIT 1				14.03		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 2				6.57		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 3				7.34		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
OLINDA_2_QF	24211	OLINDA	66	4.60	1	Western		QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.85	1	Western	Not modeled	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	1.09		Eastern	Not modeled	QF/Selfgen
PADUA_6_QF	24111	PADUA	66	8.09	1	Eastern	Not modeled	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern	Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
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	493.24	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	1.50		Western	Not modeled	QF/Selfgen
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	39.60	1	Eastern		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	9.99	1	Western		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	0.06		Eastern	Not modeled	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	1.02		Eastern	Not modeled	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.75		Eastern	Not modeled	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
VALLEY_2_QF	24160	VALLEYSC	115	7.64	1	Eastern		QF/Selfgen
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.56		Eastern	Not modeled	QF/Selfgen
VERNON_6_GONZL1				5.50		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.50		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	40.79	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	40.79	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	47.42	S3	Western		MUNI
VISTA_6_QF	24902	VSTA	66	0.04	1	Eastern		QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	46.99	1	Western		QF/Selfgen
WALNUT_6_QF	24157	WALNUT	66	7.34		Western	Not modeled	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	4.47	1	Western	Not modeled	Market
WALNUT_7_WCOVST	24157	WALNUT	66	5.70	1	Western	Not modeled	Market
WHTWTR_1_WINDA1	28061	WHITEWTR	33	16.88	1	Eastern	Monthly NQC - used August for LCR	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - historical data	Market
GARNET_1_WIND	24815	GARNET	115	1.00	W2	Eastern	No NQC - historical	Wind

							data	
GARNET_1_WIND	24815	GARNET	115	1.00	W3	Eastern	No NQC - historical data	Wind
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - historical data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.00	1	Eastern	No NQC - historical data	QF/Selfgen
INLDEM_UNIT 1	28041	IEEC-G1	19.5	405.00	1	Eastern	No NQC - Pmax	Market
INLDEM_UNIT 2	28042	IEEC-G2	19.5	405.00	2	Eastern	No NQC - Pmax	Market
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	45.00	1	Western	No NQC - historical data	QF/Selfgen
NA	24027	COLDGEN	13.8	0.00	1	Western	No NQC - historical data	Market
NA	24060	GROWGEN	13.8	0.00	1	Western	No NQC - historical data	Market
NA	24173	LBEACH5G	13.8	56.50	5	Western	No NQC - Pmax	Market
NA	24174	LBEACH6G	13.8	56.50	6	Western	No NQC - Pmax	Market
NA	24079	LBEACH7G	13.8	63.00	7	Western	No NQC - Pmax	Market
NA	24080	LBEACH8G	13.8	82.50	8	Western	No NQC - Pmax	Market
NA	24081	LBEACH9G	13.8	63.00	9	Western	No NQC - Pmax	Market
NA	28951	REFUSE	13.8	12.00	1	Western	No NQC – Pmax	Market
NA	28953	SIGGEN	13.8	25.00	1	Western	No NQC – Pmax	Market
Additional units for 2013 only:								
NA	28101	TOT032G1	13.8	107.00	1	Eastern	No NQC – Pmax	Market
NA	28102	TOT032G2	13.8	107.00	1	Eastern	No NQC – Pmax	Market
NA	28103	TOT032G3	13.8	107.00	1	Eastern	No NQC – Pmax	Market
NA	28104	TOT032G4	13.8	107.00	1	Eastern	No NQC – Pmax	Market
NA	28105	TOT032G5	13.8	107.00	1	Eastern	No NQC – Pmax	Market
NA	28106	TOT032G6	13.8	107.00	1	Eastern	No NQC – Pmax	Market
NA	28107	TOT032G7	13.8	107.00	1	Eastern	No NQC – Pmax	Market
NA	28108	TOT032G8	13.8	107.00	1	Eastern	No NQC - Pmax	Market
NA	28901	TOT041G5	18.0	175.00	5	Western	No NQC - Pmax	Market
NA	28902	TOT041G6	18.0	175.00	6	Western	No NQC - Pmax	Market
NA	28903	TOT041S7	18.0	280.00	7	Western	No NQC - Pmax	Market
NA	28201	TOT135G1	13.8	102.50	1	Western	No NQC - Pmax	Market
NA	28202	TOT135G2	13.8	102.50	1	Western	No NQC - Pmax	Market
NA	28203	TOT135G3	13.8	102.50	1	Western	No NQC - Pmax	Market
NA	28204	TOT135G4	13.8	102.50	1	Western	No NQC - Pmax	Market
NA	28205	TOT135G5	13.8	102.50	1	Western	No NQC - Pmax	Market
NA	24927	WDT165G1	13.8	108.20	1	Eastern	No NQC - Pmax	Market
NA	24928	WDT165G2	13.8	108.20	2	Eastern	No NQC - Pmax	Market
NA	24929	WDT165G3	13.8	108.20	3	Eastern	No NQC - Pmax	Market
NA	28213	WDT182G1	13.8	101.50	1	Eastern	No NQC - Pmax	Market
NA	28214	WDT182G2	13.8	101.50	1	Eastern	No NQC - Pmax	Market
NA	28215	WDT182G3	13.8	101.50	1	Eastern	No NQC - Pmax	Market
NA	28216	WDT182G4	13.8	101.50	1	Eastern	No NQC - Pmax	Market
NA	28217	WDT182G5	13.8	101.50	1	Eastern	No NQC - Pmax	Market

Major new projects modeled:

1. Palo Verde-Devers #2 500 kV line

2. Rancho Vista 500 kV substation
3. Green Path North (LADWP) – 2013 only
4. Tehachapi Transmission Project (phased in)
5. Vincent-Mira Loma 500 kV (part of Tehachapi Upgrade) – 2013 only

Critical Contingency Analysis Summary

LA Basin overall:

For 2011, the most critical contingency is the loss of the Palo Verde–Devers and Harquahala-Devers 500 kV lines with potential overload on the South of Lugo (no SPS has been modeled for this outage). This limiting contingency establishes a local capacity need of 10,019 MW (includes 908 MW of QF and wind, 788 MW of Muni and 2246 MW of nuclear generation) as the minimum capacity necessary for reliable load serving capability within this area.

For 2011, the most critical single contingency is the loss of the Palo Verde–Devers and SONGS #3 with potential overload on South of Lugo. Due to set imports, maximum path 26 flow and limited resources within SP 26 located outside of this local area the limit could not be actually achieved. However it is estimated that this limiting contingency establishes a local capacity need of about 7,000 MW (includes 908 MW of QF and wind, 788 MW of Muni and 2246 MW of nuclear generation).

For 2013, due to the addition of the Vincent-Mira Loma 500 kV line together with (LADWPs) Victorville-Hesperia-Devers LA-Devers (Green path north) 500 kV line as well as Palo Verde-Devers #2 500 kV line the imports into the LA Basin local area have increased considerably. Given that the Maximum Import Capacity is maintained fixed (see current import allocation process) the CAISO can only dispatch units outside this area and within SCE/SDG&E territory (path 26 has been maximized). The study has run out of generation in the "other SCE/SG&E areas" without being able to reach a limit in the LA Basin local area. It is estimated that the local capacity need is bellow 7000 MW and will not be bounding since the southern system will reach its zonal limits before reaching the local area limits. Further detailed analysis will be done at a later date part of the CAISO grid expansion process and will greatly depend on the new path ratings established after these new projects become operational as well as the location of future generation within SCE/SDG&E territory.

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 in 2011 case:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
24052	MTNVIST3	3	35
24053	MTNVIST4	4	35
25422	ETI MWDG	1	33
28305	ETWPKGEN	1	33
24071	INLAND	1	32
24921	MNTV-CT1	1	28
24922	MNTV-CT2	1	28
24923	MNTV-ST1	1	28
24924	MNTV-CT3	1	28
24925	MNTV-CT4	1	28
24926	MNTV-ST2	1	28
24905	RVCANAL1	R1	27
24906	RVCANAL2	R2	27
24907	RVCANAL3	R3	27
24908	RVCANAL4	R4	27
24242	RERC1G	1	27
24243	RERC2G	1	27
24244	SPRINGEN	1	27
28041	IEEC-G1	1	27
28042	IEEC-G2	2	27
25648	DVLCYN1G	1	26
25649	DVLCYN2G	2	26
25603	DVLCYN3G	3	26
25604	DVLCYN4G	4	26
25632	TERAWND	QF	26
28021	WINTEC6	1	26
25634	BUCKWND	QF	26
25635	ALTWIND	Q1	26
25635	ALTWIND	Q2	26
25637	TRANWND	QF	26
25645	VENWIND	EU	26
25645	VENWIND	Q2	26
25645	VENWIND	Q1	26
25646	SANWIND	Q2	26
28190	WINTECX2	1	26
28191	WINTECX1	1	26
28180	WINTEC8	1	26

24815	GARNET	QF	26
24815	GARNET	W3	26
24815	GARNET	W2	26
28023	WINTEC4	1	26
28060	SEAWEST	S1	26
28060	SEAWEST	S3	26
28060	SEAWEST	S2	26
28061	WHITEWTR	1	26
28280	CABAZON	1	26
25633	CAPWIND	QF	25
25639	SEAWIND	QF	25
25640	PANAERO	QF	25
28260	ALTAMSA4	1	25
25203	ANAHEIMG	1	22
24026	CIMGEN	1	21
24030	DELGEN	1	21
24140	SIMPSON	1	21
28307	MRLPKGEN	1	19
28309	BARPKGEN	1	19
24066	HUNT1 G	1	18
24067	HUNT2 G	2	18
24167	HUNT3 G	3	18
24168	HUNT4 G	4	18
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24001	ALAMT1 G	1	16
24002	ALAMT2 G	2	16
24003	ALAMT3 G	3	16
24004	ALAMT4 G	4	16
24162	ALAMT7 G	R7	16
24063	HILLGEN	1	16
24129	S.ONOFR2	2	16
24130	S.ONOFR3	3	16
24018	BRIGEN	1	14
28308	CTRPKGEN	1	14
28953	SIGGEN	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
24020	CARBOGEN	1	13
24045	ELSEG1 G	R1	13
24046	ELSEG2 G	R2	13
24064	HINSON	1	13
24070	ICEGEN	1	13
24078	LBEACH1G	1	13
24170	LBEACH2G	2	13
24171	LBEACH3G	3	13

24172	LBEACH4G	4	13
24173	LBEACH5G	5	13
24174	LBEACH6G	6	13
24079	LBEACH7G	7	13
24080	LBEACH8G	8	13
24081	LBEACH9G	9	13
24094	MOBGEN	1	13
24139	SERRFGEN	1	13
24062	HARBOR G	1	13
25510	HARBORG4	LP	13
24062	HARBOR G	HP	13
24047	ELSEG3 G	3	12
24048	ELSEG4 G	4	12
24121	REDON5 G	5	12
24122	REDON6 G	6	12
24123	REDON7 G	7	12
24124	REDON8 G	8	12
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
24027	COLDGEN	1	11
24060	GROWGEN	1	11
24120	PULPGEN	1	11
28951	REFUSE	1	11
28005	PASADNA1	1	9
28006	PASADNA2	1	9
28007	BRODWYSC	1	9

Western LA Basin Sub-area:

For 2011, the most critical contingency is the loss of the Delamo-Laguna Bell 230 kV line followed by the loss of Sylmar-Gould 230kV line, which would result in thermal overload of the Laguna Bell-Rio Hondo 230 kV line. This limiting contingency establishes a local capacity need of 5885 MW (includes 630 MW of QF, 383 of Muni and 2246 MW of nuclear generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

For 2011, the most critical single contingency could be the loss of the Rio Honda-Laguna Bell 230 kV line or the loss of the Sylmar-Eagle Rock 230 kV line with SONGS #3 unit out of service, which would result in thermal overload of the Sylmar-Gould 230 kV line. Due to set imports, maximum path 26 flow and limited resources within SP 26 located outside of this local area the limit could not be actually achieved. However it is estimated that this limiting contingency establishes a local capacity need of about 5200 MW (includes 630 MW of QF, 383 of Muni and 2246 MW of nuclear generation).

For 2013, the most critical contingency is the loss of the Mira Loma-Chino #1 230 kV line with SONGS #3 unit out of service, which would result in thermal overload of the Mira Loma-Chino #3 230 kV line. This limiting contingency establishes a local capacity need of 8585 MW (includes 630 MW of QF, 383 of Muni and 2246 MW of nuclear generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

For 2013, the most critical double contingency is the loss of the Serrano-Lewis #1 and #2 230 kV lines, which would result in thermal overload of the Lewis-Villa Park 230 kV line. This limiting contingency establishes a local capacity need of 6364 MW (includes 630 MW of QF, 383 of Muni and 2246 MW of nuclear generation).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went down by 68 MW and up by 175 MW respectively. A relatively large number of new generation and transmission projects have been modeled especially in the 2013 base case. The transmission projects are the main reason for the overall decrease in LCR needs.

LA Basin Overall Requirements:

2011	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	908	788	2246	8581	12523

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[18]	7000	0	7000
Category C (Multiple)[19]	10019	0	10019

2013	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	908	788	2246	11411	15353

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [18]	8585	0	8585
Category C (Multiple) [19]	8585	0	8585

9. Big Creek/Ventura Area

Area Definition

For 2011 the transmission tie lines into the Big Creek/Ventura Area are:

1) Vincent-Antelope 230 kV Line
2) Mesa-Antelope 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

For 2011 the substations that delineate the Big Creek/Ventura Area are:

1) Vincent is out Antelope is in
2) Mesa 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

For 2013 the transmission tie lines into the Big Creek/Ventura Area are:

[18] 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.
[19] 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) Antelope #1 500/230 kV Transformer
2) Antelope #2 500/230 kV Transformer
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

For 2011 the substations that delineate the Big Creek/Ventura Area are:

1) Antelope 500 kV is out Antelope 230 kV is in
2) Antelope 500 kV is out Antelope 230 kV is in
3) Sylmar is out Pardee is in
4) 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 2011 busload within the defined area is 5,078 MW with 107 MW of losses and 405 MW of pumps resulting in total load + losses + pumps of 5,591 MW. Total 2013 busload within the defined area is 5,226 MW with 98 MW of losses and 405 MW of pumps resulting in total load + losses of 5,729 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	18.00	1	Big Creek		Market
ANTLPE_2_QF	24457	ARBWIND	66	4.57	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24458	ENCANWND	66	23.69	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24459	FLOWIND	66	8.56	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	2.94	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24465	MORWIND	66	11.75	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24491	OAKWIND	66	3.78	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28501	MIDWIND	12	3.78	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	1.39	1	Big Creek	Monthly NQC - used August for LCR	Wind

ANTLPE_2_QF	28503	NORTHWND	12	4.07	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	2.77	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	2.69	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.94	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.68	1	Big Creek	Monthly NQC - used August for LCR	Wind
APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	60.50	1	Big Creek		Market
APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	60.50	2	Big Creek		Market
BIGCRK_2_PROJCT	24306	B CRK1-1	7.2	19.33	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24306	B CRK1-1	7.2	20.98	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24307	B CRK1-2	13.8	20.98	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24307	B CRK1-2	13.8	30.31	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24308	B CRK2-1	13.8	49.35	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24308	B CRK2-1	13.8	50.51	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24309	B CRK2-2	7.2	18.17	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24309	B CRK2-2	7.2	19.14	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24310	B CRK2-3	7.2	16.51	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24310	B CRK2-3	7.2	17.97	6	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24311	B CRK3-1	13.8	34.00	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24311	B CRK3-1	13.8	34.00	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24312	B CRK3-2	13.8	34.00	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24312	B CRK3-2	13.8	39.83	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24313	B CRK3-3	13.8	37.89	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24314	B CRK 4	11.5	48.96	41	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24314	B CRK 4	11.5	49.15	42	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24315	B CRK 8	13.8	23.70	81	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24315	B CRK 8	13.8	42.74	82	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24317	MAMOTH1G	13.8	90.83	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24318	MAMOTH2G	13.8	90.83	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24319	EASTWOOD	13.8	201.09	1	Big Creek, Rector, Vestal		Market

BIGCRK_2_PROJCT	24323	PORTAL	4.8	9.33	1	Big Creek, Rector, Vestal		Market
GOLETA_2_QF	24057	GOLETA	66	2.30		Ventura	Not modeled	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura		Market
GOLETA_6_EXGEN	24057	GOLETA	66	1.44		Ventura	Not modeled	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	9.90		Ventura	Not modeled	QF/Selfgen
KERRGN_1_UNIT 1	24437	KERNRVR	66	23.51	1	Big Creek		Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	Monthly NQC - used August for LCR	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura		Market
MONLTH_6_BOREL	24456	BOREL	66	9.24	1	Big Creek		QF/Selfgen
MOORPK_6_QF	24098	MOORPARK	66	26.86		Ventura	Not modeled	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	1.13		Ventura	Not modeled	QF/Selfgen
OMAR_2_UNITS	24102	OMAR 1G	13.8	62.60	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	62.60	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	62.60	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	62.60	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura		Market
PANDOL_6_UNIT	24113	PANDOL	13.8	19.43	1	Big Creek, Vestal		QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	15.83	2	Big Creek, Vestal		QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	5.63		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	1.83		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_QF	24212	RECTOR	66	12.70		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	1.51		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	21.64	1	Big Creek		MUNI
SAUGUS_6_QF	24135	SAUGUS	66	6.16		Big Creek	Not modeled	QF/Selfgen
SAUGUS_7_LOPEZ	24135	SAUGUS	66	6.10		Big Creek	Not modeled	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	46.76	1	Ventura		QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.37	1	Ventura		Market
SNCLRA_6_QF	24127	S.CLARA	66	2.85	1	Ventura		QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	14.08	1	Ventura		QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.59		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	1.11		Big Creek, Rector, Vestal	Not modeled Monthly NQC - used August for LCR	Market

SPRGVL_2_TULESC	24215	SPRINGVL	66	1.74		Big Creek, Rector, Vestal	Not modeled	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	75.31	1	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	75.31	2	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	75.31	3	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	75.32	4	Big Creek		QF/Selfgen
TENGEN_6_UNIT_1	24148	TENNGEN1	13.8	19.50	1	Big Creek		QF/Selfgen
TENGEN_6_UNIT_2	24149	TENNGEN2	13.8	16.57	2	Big Creek		QF/Selfgen
VESTAL_2_KERN	24152	VESTAL	66	22.67	1	Big Creek, Vestal		QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	8.16		Big Creek, Vestal	Not modeled	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.26	1	Big Creek, Vestal		QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	7.00	1	Big Creek, Vestal		QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	39.00	1	Big Creek		Market
WARNE_2_UNIT	25652	WARNE2	13.8	39.00	1	Big Creek		Market
MNDALY_6_MCGRTH	28306	MCGPKGEN	13.8	47.20	1	Ventura	No NQC - Pmax	Market
NA	24422	PALMDALE	66	1.00	1	Big Creek	No NQC - historical data	Market
NA	24436	GOLDTOWN	66	13.00	1	Big Creek	No NQC - historical data	Market
NA	28952	CAMGEN	13.8	28.00	1	Ventura	No NQC – Pmax	Market

Major new projects modeled:

1. Sylmar – Pardee 230 kV Upgrade
2. Green Path North (LADWP) – 2013 only
3. Tehachapi Transmission Project (phased in)
4. San Joaquin Cross Valley Loop

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo - Victorville 500 kV line followed by loss of one of the Sylmar - Pardee 230 kV line, which would thermally overload the remaining Sylmar - Pardee 230 kV line. This limiting contingency establishes a local capacity need of 4075 MW in 2011 and 3402 MW in 2013 (includes 836 MW of QF, 22 MW of MUNI and 73 MW of Wind generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of Sylmar-Pardee #1 (or # 2) line with Ormond #2 unit out of service, which could thermally overload the remaining Sylmar-Pardee #1 or #2 230 kV line. This limiting contingency establishes a Local Capacity

Need of 3251 MW in 2011 and 2804 MW in 2013 (includes 836 MW of QF, 22 MW of MUNI and 73 MW of Wind generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within the Big Creek/Ventura area for the 2011 case:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
24009	APPGEN1G	1	25
24010	APPGEN2G	2	25
24107	ORMOND1G	1	25
24108	ORMOND2G	2	25
24118	PITCHGEN	1	25
24148	TENNGEN1	1	25
24149	TENNGEN2	2	25
25651	WARNE1	1	24
25652	WARNE2	1	24
28004	ELLWOOD	1	24
28052	PSTRIAG2	G2	23
28051	PSTRIAG1	G1	23
25605	EDMON1AP	1	23
25607	EDMON3AP	3	23
25607	EDMON3AP	4	23
25608	EDMON4AP	5	23
25608	EDMON4AP	6	23
25609	EDMON5AP	7	23
25609	EDMON5AP	8	23
25610	EDMON6AP	9	23
25610	EDMON6AP	10	23
25611	EDMON7AP	11	23
25611	EDMON7AP	12	23
25612	EDMON8AP	13	23
25612	EDMON8AP	14	23
24089	MANDLY1G	1	23
24090	MANDLY2G	2	23
24222	MANDLY3G	3	23
24110	OXGEN	1	23
24119	PROCGEN	1	23
24159	WILLAMET	1	23
24127	S.CLARA	1	23
28306	MCGPKGEN	1	23
28952	CAMGEN	1	23
28055	PSTRIAS2	S2	22
28054	PSTRIAG3	G3	22
28053	PSTRIAS1	S1	22
25606	EDMON2AP	2	22
25614	OSO A P	1	22
25614	OSO A P	2	22

25615	OSO B P	7	22
25615	OSO B P	8	22
25653	ALAMO SC	1	22
24113	PANDOL	1	21
24113	PANDOL	2	21
24152	VESTAL	1	21
24102	OMAR 1G	1	20
24103	OMAR 2G	2	20
24104	OMAR 3G	3	20
24105	OMAR 4G	4	20
28008	LAKEGEN	1	20
24143	SYCCYN1G	1	20
24144	SYCCYN2G	2	20
24145	SYCCYN3G	3	20
24146	SYCCYN4G	4	20
24150	ULTRAGEN	1	20
24319	EASTWOOD	1	19
24306	B CRK1-1	1	19
24306	B CRK1-1	2	19
24307	B CRK1-2	3	19
24307	B CRK1-2	4	19
24308	B CRK2-1	1	19
24308	B CRK2-1	2	19
24309	B CRK2-2	3	19
24309	B CRK2-2	4	19
24310	B CRK2-3	5	19
24310	B CRK2-3	6	19
24311	B CRK3-1	1	19
24311	B CRK3-1	2	19
24312	B CRK3-2	3	19
24312	B CRK3-2	4	19
24313	B CRK3-3	5	19
24314	B CRK 4	41	19
24314	B CRK 4	42	19
24315	B CRK 8	81	19
24315	B CRK 8	82	19
24317	MAMOTH1G	1	19
24318	MAMOTH2G	2	19
24437	KERNRVR	1	19
24457	ARBWIND	1	16
28503	NORTHWND	1	16
28504	ZONDWND1	1	16
28505	ZONDWND2	1	16
24458	ENCANWND	1	15
24459	FLOWIND	1	15
24460	DUTCHWND	1	15
24436	GOLDTOWN	1	15
24465	MORWIND	1	15
28501	MIDWIND	1	15
25617	PEARBMAP	1	7

25617	PEARBMAP	2	7
25618	PEARBMBP	5	7
25618	PEARBMBP	6	7
24136	SEAWEST	1	7
25619	PEARBMCP	7	6
25619	PEARBMCP	8	6
25620	PEARBMDP	9	6

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within the Big Creek/Ventura area for the 2013 case:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
24148	TENNGEN1	1	25
24149	TENNGEN2	2	25
24009	APPGEN1G	1	24
24010	APPGEN2G	2	24
24118	PITCHGEN	1	24
24089	MANDLY1G	1	23
24107	ORMOND1G	1	23
24108	ORMOND2G	2	23
24119	PROCGEN	1	23
25651	WARNE1	1	23
25652	WARNE2	1	23
24127	S.CLARA	1	23
28004	ELLWOOD	1	23
28306	MCGPKGEN	1	23
28055	PSTRIAS2	S2	22
28054	PSTRIAG3	G3	22
28052	PSTRIAG2	G2	22
28051	PSTRIAG1	G1	22
24222	MANDLY3G	3	22
25605	EDMON1AP	1	21
24090	MANDLY2G	2	21
24110	OXGEN	1	21
24159	WILLAMET	1	21
25614	OSO A P	1	21
25614	OSO A P	2	21
28952	CAMGEN	1	21
28053	PSTRIAS1	S1	20
25606	EDMON2AP	2	20
25607	EDMON3AP	3	20
25607	EDMON3AP	4	20
25608	EDMON4AP	5	20
25608	EDMON4AP	6	20
25609	EDMON5AP	7	20
25609	EDMON5AP	8	20
25610	EDMON6AP	9	20
25610	EDMON6AP	10	20
25611	EDMON7AP	11	20

25611	EDMON7AP	12	20
25612	EDMON8AP	13	20
25612	EDMON8AP	14	20
25615	OSO B P	7	20
25615	OSO B P	8	20
25653	ALAMO SC	1	20
24311	B CRK3-1	1	19
24311	B CRK3-1	2	19
24312	B CRK3-2	3	19
24312	B CRK3-2	4	19
24313	B CRK3-3	5	19
24113	PANDOL	1	18
24113	PANDOL	2	18
28008	LAKEGEN	1	18
24150	ULTRAGEN	1	18
24152	VESTAL	1	18
24319	EASTWOOD	1	18
24306	B CRK1-1	1	18
24306	B CRK1-1	2	18
24314	B CRK 4	41	18
24314	B CRK 4	42	18
24317	MAMOTH1G	1	18
24318	MAMOTH2G	2	18
24102	OMAR 1G	1	17
24103	OMAR 2G	2	17
24104	OMAR 3G	3	17
24105	OMAR 4G	4	17
24143	SYCCYN1G	1	17
24144	SYCCYN2G	2	17
24145	SYCCYN3G	3	17
24146	SYCCYN4G	4	17
24307	B CRK1-2	3	17
24307	B CRK1-2	4	17
24308	B CRK2-1	1	17
24308	B CRK2-1	2	17
24309	B CRK2-2	3	17
24309	B CRK2-2	4	17
24310	B CRK2-3	5	17
24310	B CRK2-3	6	17
24315	B CRK 8	81	17
24315	B CRK 8	82	17
24437	KERNRVR	1	17
24458	ENCANWND	1	14
24459	FLOWIND	1	14
24460	DUTCHWND	1	14
24465	MORWIND	1	14
24436	GOLDTOWN	1	13
24457	ARBWIND	1	12
28501	MIDWIND	1	12
28503	NORTHWND	1	12

28504	ZONDWND1	1	12
28505	ZONDWND2	1	12
25617	PEARBMAP	1	5
25617	PEARBMAP	2	5
25618	PEARBMBP	5	5
25618	PEARBMBP	6	5
25620	PEARBMDP	9	5

Rector Sub-area:

The most critical contingency is the loss of the Rector - Vestal 230 kV line with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a local capacity need of 552 MW in 2011 and 347 MW in 2013 (includes 15 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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 is the loss of the Magunden - Vestal 230 kV line with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a local capacity need of 676 MW in 2011 and 572 MW in 2013 (includes 122 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 within Big Creek that are at least 5% effective to the constraint on the Magunden – Vestal 230 kV line for 2011 case.

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
24113	PANDOL	1	44
24113	PANDOL	2	44
28008	LAKEGEN	1	44
24150	ULTRAGEN	1	44
24152	VESTAL	1	44
24319	EASTWOOD	1	23
24306	B CRK1-1	1	23
24306	B CRK1-1	2	23
24307	B CRK1-2	3	23
24307	B CRK1-2	4	23
24308	B CRK2-1	1	23
24308	B CRK2-1	2	23
24309	B CRK2-2	3	23
24309	B CRK2-2	4	23
24315	B CRK 8	81	23
24315	B CRK 8	82	23
24310	B CRK2-3	5	22
24310	B CRK2-3	6	22
24311	B CRK3-1	1	22
24311	B CRK3-1	2	22
24312	B CRK3-2	3	22
24312	B CRK3-2	4	22
24313	B CRK3-3	5	22
24317	MAMOTH1G	1	22
24318	MAMOTH2G	2	22
24314	B CRK 4	41	21
24314	B CRK 4	42	21

The following table has units within Big Creek that are at least 5% effective to the constraint on the Magunden – Vestal 230 kV line for 2013 case.

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
24113	PANDOL	1	40
24113	PANDOL	2	40
28008	LAKEGEN	1	40
24150	ULTRAGEN	1	40
24152	VESTAL	1	40
24319	EASTWOOD	1	27
24306	B CRK1-1	1	27
24306	B CRK1-1	2	27
24307	B CRK1-2	3	27
24307	B CRK1-2	4	27
24308	B CRK2-1	1	27
24308	B CRK2-1	2	27
24309	B CRK2-2	3	27
24309	B CRK2-2	4	27
24310	B CRK2-3	5	27
24310	B CRK2-3	6	27
24311	B CRK3-1	1	27
24311	B CRK3-1	2	27
24312	B CRK3-2	3	27
24312	B CRK3-2	4	27
24313	B CRK3-3	5	27
24315	B CRK 8	81	27
24315	B CRK 8	82	27
24317	MAMOTH1G	1	27
24318	MAMOTH2G	2	27
24314	B CRK 4	41	26
24314	B CRK 4	42	26

Changes compared to last year's results:

Overall the load forecast went down by 176 MW and 316 MW respectively or about 3-5%. A relatively large number of transmission projects have been modeled especially in the 2013 base case. In last year's results all the major projects have been modeled in the 2010 as well as the 2012 base cases, this year they are only modeled in the 2013 base case as such the results for 2011 have higher LCR requirements. The transmission projects are the main reason for the overall trend in the decrease of LCR needs.

Big Creek/Ventura Overall Requirements:

	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	909	22	4229	5160

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[20]	3251	0	3251
Category C (Multiple)[21]	4075	0	4075

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[20]	2804	0	2804
Category C (Multiple)[21]	3402	0	3402

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

The substations that delineate the San Diego Area are:

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

Total 2011 busload within the defined area: 5089 MW with 117 MW of losses resulting in total load + losses of 5206 MW. Total 2013 busload within the defined area: 5227 MW with 130 MW of losses resulting in total load + losses of 5357 MW.

[20] 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.
[21] 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.

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-Otay		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	3.11	1	None		QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.50	1	None		QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	1.00	1	None		QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	2.50	2	None		QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	3.53	1	None		QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	8.82	1	None	Monthly NQC - used August for LCR	Wind
DIVSON_6_NSQF	22172	DIVISION	69	47.00	1	None		QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	0.89	1	None		QF/Selfgen
ELCAJN_6_UNITA1	22150	CALPK_EC	13.8	42.20	1	El Cajon		Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	13.00	1	El Cajon		Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1	None		Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	103.00	1	None		Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	109.00	1	None		Market
ENCINA_7_EA4	22240	ENCINA 4	22	299.00	1	None		Market
ENCINA_7_EA5	22244	ENCINA 5	24	329.00	1	None		Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.00	1	None		Market
ESCNDO_6_PL1X2	22257	MMC_ES	13.8	35.50	1	None		Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	45.50	1	None		Market
ESCO_6_GLMQF	22332	GOALLINE	69	46.79	1	None		QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	15.00	1	Rose Canyon		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	14.00	1	Rose Canyon		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	14.00	2	Rose Canyon		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	14.00	1	Rose Canyon		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	13.00	2	Rose Canyon		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.00	1	Rose Canyon		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	15.00	2	Rose Canyon		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.00	1	Rose Canyon		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.00	2	Rose Canyon		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	Border-Otay		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	Border-Otay		Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	46.60	1	None		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.00	1	None		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	16.00	2	None		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	2.93	1	None		QF/Selfgen
MSSION_2_QF	22496	MISSION	69	2.10	1	None		QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	35.58	1	None		QF/Selfgen
OTAY_6_PL1X2	22617	MMC_OY	13.8	35.50	1	None		Market
OTAY_6_UNITB1	22604	OTAY	69	1.42	1	None		QF/Selfgen
OTAY_6_UNITB1	22604	OTAY	69	1.41	2	None		QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	3.40	3	None		QF/Selfgen
PALOMR_2_PL1X3	22262	PEN_CT1	18	155.42	1	None		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	155.42	1	None		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	230.64	1	None		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.29	2	None		QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	22.19	1	None		QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	9.39	1	None		QF/Selfgen

SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.99	1	None		QF/Selfgen
SOBAY_7_GT1	22776	SOUTHBGT	12.5	15.00	1	None	Not Modeled	Market
SOBAY_7_SY1	22780	SOUTHBY1	15	146.00	1	None	Not Modeled	Market
SOBAY_7_SY2	22784	SOUTHBY2	15	149.60	1	None	Not Modeled	Market
SOBAY_7_SY3	22788	SOUTHBY3	20	175.00	1	None	Not Modeled	Market
SOBAY_7_SY4	22792	SOUTHBY4	20	222.00	1	None	Not Modeled	Market
KYCORA_7_UNIT 1	22384	KYOCERA	69	0.00	1	None	No NQC - historical 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
MARGTA_1_UNIT 1	22433	MARGARTA	138	44.00	1	None	No NQC - Pmax	Market
NA	22008	ASH	69	0.90	1	None	No NQC - historical data	QF/Selfgen
NA	22532	MURRAY	69	0.20	1	None	No NQC - historical data	QF/Selfgen
NA	22680	R.SNTAFE	69	0.40	1	None	No NQC - historical data	QF/Selfgen
NA	22680	R.SNTAFE	69	0.30	2	None	No NQC - historical data	QF/Selfgen
NA	22756	SCRIPPS	69	0.00	1	None	No NQC - historical data	QF/Selfgen
NA	22760	SHADOWR	138	0.10	1	None	No NQC - historical data	QF/Selfgen
NA	22870	VALCNTR	69	0.10	1	None	No NQC - historical data	QF/Selfgen
NA	22916	PFC-AVC	0.6	0.00	1	None	No NQC - historical data	QF/Selfgen
New Unit	22624	PALA	69	46.80	1	None	No NQC - Pmax	Market
New Unit	22624	PALA	69	46.80	2	None	No NQC - Pmax	Market
OTMESA_2_PL1X3	22605	OTAYMGT1	18	172.00	1	None	No NQC - Pmax	Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	172.00	1	None	No NQC - Pmax	Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	217.00	1	None	No NQC - Pmax	Market
New unit	23120	BULLMOOS	13.8	27.00	1	None	No NQC - Pmax	Market

Additional units available in 2011-13 for the Greater Imperial Valley-San Diego area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	NQC Comments	CAISO Tag
TERMEX_2_CTG1	22982	IV GEN2	18	156	1		Market
TERMEX_2_CTG2	22983	IVGEN2	18	156	1		Market
TERMEX_2_PL1X3	22981	IV GEN1	18	281	1		Market
LAROA2_2_UNITA1	22996	INTBST	18	157	1		Market
LAROA2_2_UNITA1	22997	INTBCT	16	165	1		Market
LAROA1_2_UNITA1	20187	LRP-U1	16	165	1		Market
2011-2013 Additional		**Total**		**1080**			

Major new projects modeled:

1. Sunrise 500 kV line
2. Otay Mesa (with 230 kV transmission line upgrades past Miguel)
3. South Bay area transmission upgrades due to South Bay PP retire

Critical Contingency Analysis Summary

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632), which could overload the El Cajon-Los Coches 69 kV line. This limiting contingency establishes a local capacity need of 86 MW (including 0 MW of QF and 31 MW of deficiency) in 2011 and 89 MW (includes 0 MW of QF and 34 MW of deficiency) in 2013.

Effectiveness factors:

All units within this sub-area (El Cajon Peaker and El Cajon GT) are needed therefore no effectiveness factor is required.

Rose Canyon Sub-area

The most critical contingency for the Rose Canyon Sub-area is the loss of Old Town-Pacific Beach 69 kV line (TL613) followed by the loss of Rose Canyon-Penasquitos 69 kV line (TL661), which could overload the Eastgate – Rose Canyon 69 kV line (TL6927). This limiting contingency establishes a local capacity need of 91 MW (including 0 MW of QF) in 2011 and 103 MW (includes 0 MW of QF) in 2013.

Effectiveness factors:

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

Bernardo Sub-area

The most critical contingency for the Bernardo Sub-area is the loss of Artesian - Sycamore 69 kV line (TL6920) followed by the loss of Poway-Rancho Carmel 69 kV line (TL648), which could overload the Felicita Tap – Bernardo 69 kV line (TL689). This limiting contingency establishes a local capacity need of 66 MW (including 0 MW of QF and 26 MW of deficiency) in 2011 and 77 MW (includes 0 MW of QF and 37 MW of deficiency) in 2013.

Effectiveness factors:

All units within this area (Lake Hodge) are needed therefore no effectiveness factor is required.

Escondido Sub-area

Due to short term ratings for the Escondido 230/69 kV transformers and an operating procedure to drop load after the second contingency, the need for this sub-area has been eliminated.

Border-Otay Sub-area

The most critical contingency for the Border – Otay Sub-area is the loss of Border – Miguel 69 kV line (TL6910) followed by the loss of Imperial Beach-Otay-Syo 69 kV line (TL623), which could overload Otay-Otay Lake Tap (TL649) above it's 30 minute rating. This limiting contingency establishes a local capacity need of 19 MW in 2011 and 24 MW in 2013 (includes 0 MW of QF).

Effectiveness factors:

All units in this sub-area (Boarder and Larkspur) have the same effectiveness factors.

San Diego overall:

The most limiting contingency in the San Diego area is the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations with the Otay Mesa Combined-Cycle Power plant (561 MW) out of service while staying within the maximum import achieved after the new Sunrise 500 kV line is in service (3,500 MW). This limiting contingency establishes a local capacity need of 2267 MW in 2011 and 2418 MW in 2013 (includes 192 MW of QF generation and 9 MW of wind) as the minimum capacity necessary for reliable load serving capability within this area. The outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations followed by Sunrise 500 kV line will push the flow on South of San Onofre (WECC Path 44) to above its 2,500 MW rating; however all equipment will be within Applicable Rating. For consideration of LCR and in order to return the system (within 30 minutes) to the import capability rating of Path 44 (2,500 MW), if additional resources in the area are not available the reliability criteria permits load drop in San Diego.

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 (561 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 3267 MW in 2011 and 3418 MW in 2013 (includes 192 MW of QF generation and 9 MW of wind) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Changes compared to last year's results:

Overall the load forecast went up by 74 MW and 89 MW respectively or about 1.5% and that lead to an increase in the LCR by same amount. The small decrease in local capacity need for some of the sub-areas compared to the previous study (2010-2012) can be explained by the fact that even though the overall load forecast for San Diego area increased from years 2010 to 2011 and from years 2012 to 2013, some of the loads in the near vicinity of the sub-areas decreased.

San Diego Overall Requirements:

	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	192	9	2781	2982

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[22]	2267	0	2267
Category C (Multiple)[23]	2267	57	2324

[22] 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.

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[22]	2418	0	2418
Category C (Multiple)[23]	2418	71	2489

[23] 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.