



California ISO
Your Link to Power

California Independent
System Operator

2011 LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT AND STUDY RESULTS

April 30, 2010

Local Capacity Technical Study Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2011 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2011 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 24, 2009. On balance, the assumptions, processes, and criteria used for the 2011 LCT Study mirror those used in the 2007-2010 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group (“LSAG”)¹, an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2011 LCT study results are provided to the CPUC for consideration in its 2011 resource adequacy requirements program. These results will also be used by the CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as “Local Capacity Requirements” or “LCR”) and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Criteria notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).² In this regard, the 2011 LCT Study also provides additional information on sub-area needs and effectiveness factors (where applicable) in order to allow LSEs to engage in more informed procurement.

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

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

Below is a comparison of the 2011 vs. 2010 total LCR:

2011 Local Capacity Requirements

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

2010 Local Capacity Requirements

Local Area Name	Qualifying Capacity			2010 LCR Need Based on Category B			2010 LCR Need Based on Category C with operating procedure		
	QF/ Muni (MW)	Market (MW)	Total (MW)	Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Local Area Name	QF/ Muni (MW)
Humboldt	48	135	183	176	0	176	176	0	176
North Coast / North Bay	149	736	885	787	0	787	787	3	790
Sierra	1066	769	1835	1133	102	1235	1717	385	2102
Stockton	229	266	495	357	0	357	432	249	681
Greater Bay	1096	5608	6704	4224	0	4224	4651	0	4651
Greater Fresno	502	2439	2941	2310	0	2310	2640	0	2640
Kern	656	9	665	187	0	187	403	1	404
LA Basin	3918	8212	12130	9735	0	9735	9735	0	9735
Big Creek/ Ventura	947	4146	5093	3212	0	3212	3334	0	3334
San Diego	205	3502	3707	3200	0	3200	3200	14	3214
Total	8816	25822	34638	25321	102	25423	27075	652	27727

Overall, the LCR needs are steady from 2010 to 2011. The total LCR needs have increased by about 331 MW, however the existing capacity needed to meet the LCR has increased by only 19 MW. The LCR needs have decreased in the following areas: North Coast/North Bay, Sierra, Fresno, Big Creek/Ventura and San Diego due to downward trend for load. The LCR needs have slightly increased in Humboldt due to new Humboldt Bay Power Plant configuration, Greater Bay due to the Potrero Power Plant retirement, Kern due to load growth and LA Basin due to load growth and permanent retirement of the Antelope-Mesa Cal 230 kV line (as required per TRTP – in order to make room for a new 500 kV line). The Stockton LCR needs are steady. 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 2011 and 2010 LCRs.

Table of Contents

I.	Executive Summary 1	
II.	Study Overview: Inputs, Outputs and Options	5
A.	<i>Objectives</i>	5
B.	<i>Key Study Assumptions</i>	5
1.	Inputs and Methodology	5
C.	<i>Grid Reliability</i>	7
D.	<i>Application of N-1, N-1-1, and N-2 Criteria</i>	8
E.	<i>Performance Criteria</i>	8
F.	<i>The Two Options Presented In This LCR Study</i>	14
1.	Option 1- Meet Performance Criteria Category B	15
2.	Option 2- Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions	15
III.	Assumption Details: How the Study was Conducted	15
A.	<i>System Planning Criteria</i>	15
1.	Power Flow Assessment:	17
2.	Post Transient Load Flow Assessment:	18
3.	Stability Assessment:	18
B.	<i>Load Forecast</i>	18
1.	System Forecast	18
2.	Base Case Load Development Method.....	19
C.	<i>Power Flow Program Used in the LCR analysis</i>	20
IV.	Locational Capacity Requirement Study Results	21
A.	<i>Summary of Study Results</i>	21
B.	<i>Summary of Zonal Needs</i>	23
C.	<i>Summary of Results by Local Area</i>	25
1.	Humboldt Area.....	25
2.	North Coast / North Bay Area	29
3.	Sierra Area	34
4.	Stockton Area.....	45
5.	Greater Bay Area	49
6.	Greater Fresno Area.....	57
7.	Kern Area.....	64
8.	LA Basin Area	68
9.	Big Creek/Ventura Area	79
10.	San Diego Area.....	90

II. Study Overview: Inputs, Outputs and Options

A. Objectives

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

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2011 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2011 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 24, 2009.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2011 LCT Study:

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

Issue:	How Incorporated into THIS LCT Study:
<u>Input Assumptions:</u>	
<ul style="list-style-type: none"> • 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.
<ul style="list-style-type: none"> • 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
<ul style="list-style-type: none"> • Load Forecast 	Uses a 1-in-10 year summer peak load forecast
<u>Methodology:</u>	
<ul style="list-style-type: none"> • <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.
<ul style="list-style-type: none"> • <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 LCT Study.
<ul style="list-style-type: none"> • <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>	
<ul style="list-style-type: none"> • <u>Performance Level B & C, including incorporation of PTO operational solutions</u> 	This LCT Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, of the study year. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study.
<u>Load Pocket:</u>	
<ul style="list-style-type: none"> • <u>Fixed Boundary, including limited reference to published effectiveness factors</u> 	This LCT Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2011 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council (“WECC”) that incorporate standards set by the North American Electric Reliability Council (“NERC”) (collectively “NERC Planning Standards”). The NERC Planning Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.³ The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all “Applicable Reliability Criteria.” Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with the CAISO’s Participating Transmission Owners (“PTOs”), which affect a PTO’s individual system.

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

³ Pub. Utilities Code § 345

there are other levels of performance where security can be maintained without ensuring adequacy.

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

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

The N-1-1 vs N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 (“category B contingency, manual system adjustment, followed by another category B contingency”). The N-2 represents NERC Category C5 (“any two circuits of a multiple circuit tower line”) as well as WECC-S2 (for 500 kV only) (“any two circuits in the same right-of-way”) with no manual system adjustment between the two contingencies.

E. Performance Criteria

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

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.⁴ All Category C requirements in this report refer to situations when in real time

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

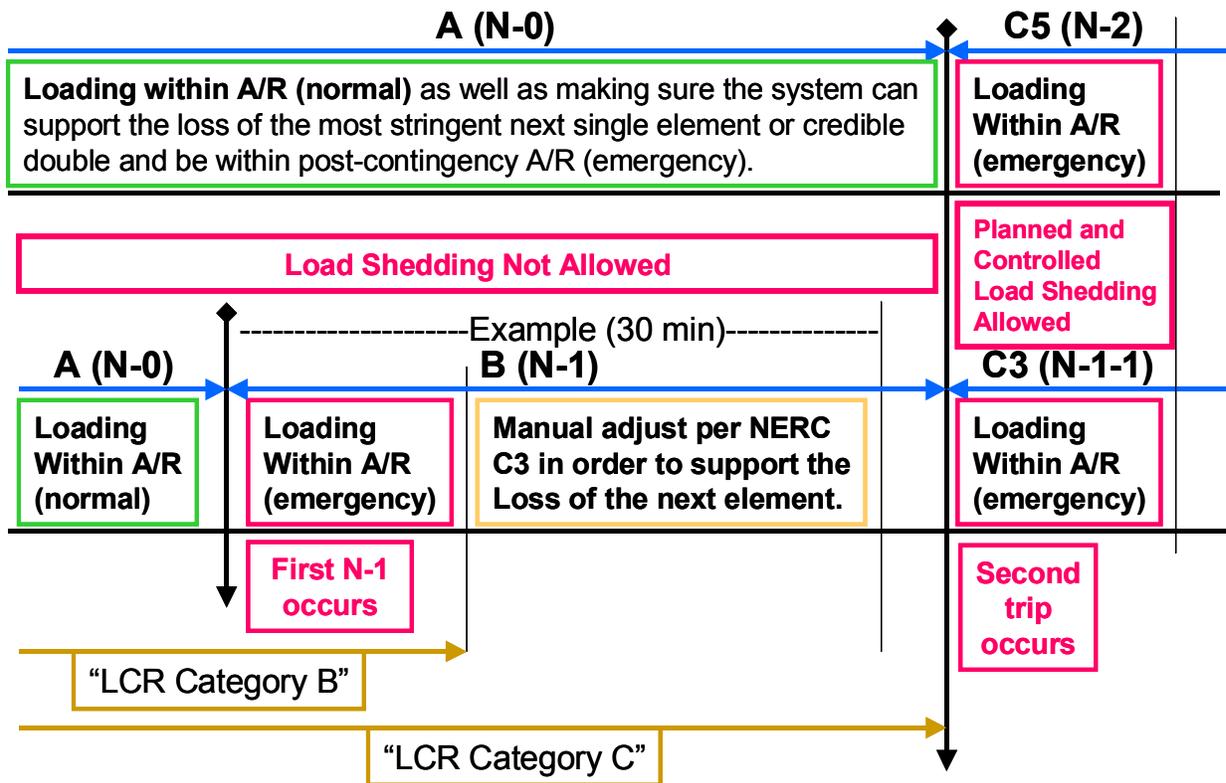
(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

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)**.

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



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

Applicable Rating:

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

Normal rating is to be used under normal conditions.

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

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

length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.

Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

Controlled load drop:

This is achieved with the use of a Special Protection Scheme.

Planned load drop:

This is achieved when the most limiting equipment has short-term emergency ratings AND the operators have an operating procedure that clearly describes the actions that need to be taken in order to shed load.

Special Protection Scheme:

All known SPS shall be assumed. New SPS must be verified and approved by the CAISO and must comply with the new SPS guideline described in the CAISO Planning Standards.

System Readjustment:

This represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

Actions that can be taken as system readjustment after a single contingency (Category B):

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

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

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

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

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

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.

F. The Two Options Presented In This LCT Report

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

1. Option 1- Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.⁵

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

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

Table 4: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Criteria	Old RMR Criteria	Local Capacity Criteria
<u>A – No Contingencies</u>	X	X	X
<u>B – Loss of a single element</u>			
1. Generator (G-1)	X	X	X ¹
2. Transmission Circuit (L-1)	X	X	X ¹
3. Transformer (T-1)	X	X ²	X ^{1,2}
4. Single Pole (dc) Line	X	X	X ¹
5. G-1 system readjusted L-1	X	X	X
<u>C – Loss of two or more elements</u>			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode) L-2	X		X
6. SLG fault (stuck breaker or protection failure) for G-1	X		
7. SLG fault (stuck breaker or protection failure) for L-1	X		
8. SLG fault (stuck breaker or protection failure) for T-1	X		
9. SLG fault (stuck breaker or protection failure) for Bus section	X		
WECC-S3. Two generators (Common Mode) G-2	X ³		X
<u>D – Extreme event – loss of two or more elements</u>			
Any B1-4 system readjusted (Common Mode) L-2	X ⁴		X ³
All other extreme combinations D1-14.	X ⁴		
<p>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.</p> <p>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.</p> <p>3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.</p> <p>4 Evaluate for risks and consequence, per NERC standards.</p>			

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

1. Power Flow Assessment:

<u>Contingencies</u>	<u>Thermal Criteria</u> ³	<u>Voltage Criteria</u> ⁴
Generating unit ^{1, 6}	Applicable Rating	Applicable Rating
Transmission line ^{1, 6}	Applicable Rating	Applicable Rating
Transformer ^{1, 6}	Applicable Rating ⁵	Applicable Rating ⁵
(G-1)(L-1) ^{2, 6}	Applicable Rating	Applicable Rating
Overlapping ^{6, 7}	Applicable Rating	Applicable Rating

- ¹ All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners’ local area systems.
- ² Key generating unit out, system readjusted, followed by a line outage. This overlapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.
- ³ Applicable Rating – Based on ISO Transmission Register or facility upgrade plans including established Path ratings.
- ⁴ Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.
- ⁵ A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
- ⁶ Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.
- ⁷ During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding.

SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

<u>Contingencies</u> Selected ¹	<u>Reactive Margin Criteria</u> 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:

<u>Contingencies</u> Selected ¹	<u>Stability Criteria</u> ² Applicable Rating
--	--

- ¹ Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.
- ² Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

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

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division⁶ 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.

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

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

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 17.0. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

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

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

during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

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

Table 5: 2011 Local Capacity Needs vs. Peak Load and Local Area Generation

	2011 Total LCR (MW)	Peak Load (1 in10) (MW)	2011 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2011 LCR as % of Total Area Generation
Humboldt	205	206	100%	223	92%**
North Coast/North Bay	734	1574	47%	861	85%
Sierra	2082	1977	105%	1816	115%**
Stockton	682	1163	59%	526	130%**
Greater Bay	4878	10322	47%	6506	75%**
Greater Fresno	2448	3306	74%	2919	84%**
Kern	447	1387	32%	708	63%**
LA Basin	10589	20223	52%	12309	86%
Big Creek/Ventura	2786	4648	60%	5306	53%
San Diego	3207	5036	64%	3421	94%**
Total	28,058	49842*	56%*	34,595	81%

Table 6: 2010 Local Capacity Needs vs. Peak Load and Local Area Generation

	2010 Total LCR (MW)	Peak Load (1 in10) (MW)	2010 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2010 LCR as % of Total Area Generation
Humboldt	176	203	87%	183	96%
North Coast/North Bay	790	1614	49%	885	89%**
Sierra	2102	2126	99%	1835	115%**
Stockton	681	959	71%	495	138%**
Greater Bay	4651	10276	45%	6704	69%
Greater Fresno	2640	3377	78%	2941	90%
Kern	404	1240	33%	665	61%**
LA Basin	9735	20058	49%	12130	80%
Big Creek/Ventura	3334	5033	66%	5093	65%
San Diego	3214	5127	63%	3707	87%**
Total	27,727	50,013*	55%*	34,638	80%

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

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

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

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

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

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become

operational before 6/1/2011 have been included in this 2011 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, “2011 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, “2011 LCR Requirement Based on Category C with Operating Procedure”, sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

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

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	28363	4254	-8544	-3750	20323
NP26=NP15+ZP26	21988	3298	-4885	-2902	17499

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2011.

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

Allocated Imports are the actual 2010 numbers that are not expected to change much by 2011 because there are no additional transmission additions to the grid between now and summer of 2011.

Allocated Path 26 flow The CAISO determines the amount of Path 26 transfer capacity available for RA counting purposes after accounting for (1) Existing Transmission Contracts (ETCs) that serve load outside the CAISO Balancing Area⁷ and (2) loop flow⁸ from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North).

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

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

Changes compared to last year's results:

- The load forecast went down in Southern California by about 500 MW and down in Northern California by about 250 MW.
- The Import Allocations went up in Southern California by about 450 MW and up in Northern California by about 370 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2010. If there are any changes, they will be heavily influenced by the pre-existing “grandfathered contracts” and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

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

⁸ “Loop flow” is a phenomenon common to large electric power systems like the Western Electricity Coordinating Council. Power is scheduled to flow point-to-point on a Day-ahead and Hour-ahead basis through the CAISO. However, electric grid physics prevails and the actual power flow in real-time will differ from the pre-arranged scheduled flows. Loop flow is real, physical energy and it uses part of the available transfer capability on a path. If not accommodated, loop flow will cause overloading of lines, which can jeopardize the security and reliability of the grid.

C. Summary of Results by Local Area

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

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: 197 MW with 9 MW of losses resulting in total load + losses of 206 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
BRDGLV_7_BAKER				0.00		None	Not modeled	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.99	1	Humboldt 60 kV		QF/Selfgen
FTSWRD_7_QFUNTS				0.64		Humboldt 60 kV	Not modeled	QF/Selfgen
HUMBPP_1_MOBLE2	31154	HUMBOLDT	13.2	15.00	2	None	Retired	Market
HUMBPP_1_MOBLE3	31154	HUMBOLDT	13.2	15.00	1	None	Retired	Market
HUMBPP_7_UNIT 1	31170	HMBOLDT1	13.8	52.00	1	Humboldt 60 kV	Retired	Market
HUMBPP_7_UNIT 2	31172	HMBOLDT2	13.8	53.00	1	Humboldt 60 kV	Retired	Market
HUMBSB_1_QF				0.00		None	Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV		QF/Selfgen

LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.25	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.24	2	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.95	3	Humboldt 60 kV		QF/Selfgen
WLLWCR_6_CEDRFL				0.00		Humboldt 60 kV	Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	Humboldt 60 kV	No NQC - historical data	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	1	None	No NQC - Pmax	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	2	None	No NQC - Pmax	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	3	None	No NQC - Pmax	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	4	None	No NQC - Pmax	Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	5	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	6	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	7	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS3	31182	HUMB_G2	13.8	16.60	8	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS3	31182	HUMB_G2	13.8	16.60	9	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS3	31182	HUMB_G2	13.8	16.60	10	Humboldt 60 kV	No NQC - Pmax	Market

Major new projects modeled:

1. Humboldt Bay Repower
2. Humboldt Reactive Support
3. Maple Creek Reactive Support
4. Garberville Reactive Support

Critical Contingency Analysis Summary

Humboldt 60 kV Sub-area:

The most critical contingency for the Humboldt 60 kV Sub-area area is the outage of the Humboldt 115/60 Transformer and one of the gen tie-line connecting the new Humboldt Bay units (on 60 kV side). The area limitation is the overload on the parallel Humboldt 115/60 kV Transformer. This contingency establishes a LCR of 174 MW in 2011 (includes 57 MW of QF/Selfgen generation as well as 17 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the outage of the Humboldt 115/60 kV Transformer. The limitation is thermal overload on the parallel Humboldt 115/60 kV Transformer. This limiting contingency establishes a LCR of 147 MW in 2011 (includes 57 MW of QF/Selfgen generation).

Effectiveness factors:

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

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

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV Line overlapping with an outage of one of the tie-line connecting the new Humboldt Bay units. The area limitation is the overload on the Humboldt – Trinity 115 kV Line. This contingency establishes a LCR of 188 MW in 2011 (includes 57 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

For the single contingency, generation capacity to mitigate overloading facilities identified in Humboldt 60 kV Sub-area is sufficient to mitigate potential overload for the overall system.

Effectiveness factors:

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

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

Changes compared to last year's results:

The Humboldt Repowering Project (HBPP) was modeled an on-line in the 2011 LCR studies. Two new transmission projects, the Maple Creek and Garberville Reactive support projects were also modeled. While the overall load is steady, the LCR need has increased due to the change in system configuration after the addition of the new Humboldt Bay Power Plant. Furthermore, new transmission projects have resulted in different type of limiting facilities as such the reactive power is no longer the biggest concern. Overall the LCR has increased by 29 MW, however the LCR resource need has only increase by 12 MW.

Humboldt Overall Requirements:

2011	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	57	0	166	223

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ⁹	147	0	147
Category C (Multiple) ¹⁰	188	17	205

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

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. 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: 1511 MW with 63 MW of losses resulting in total load + losses of 1574 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.18		Fulton, Lakeville	Not modeled	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	60.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market

¹⁰ Multiple contingencies means that the system will be able to 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.

GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	47.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	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	38.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYSRVL_7_WSPRNG				1.68		Fulton, Lakeville	Not modeled	QF/Selfgen
HIWAY_7_ACANYN				1.26		Lakeville	Not modeled	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	0.80	1	Eagle Rock, Fulton, Lakeville		QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.74	1	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.74	2	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.65	3	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
NAPA_2_UNIT				0.02		Lakeville	Not modeled	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	32.00	1	Lakeville		MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	29.00	1	Lakeville		MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	28.00	1	Fulton, Lakeville		MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	27.00	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				0.03		Eagle Rock, Fulton, Lakeville	Not modeled	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market

SMUDGO_7_UNIT 1	31430	SMUDGE01	13.8	37.00	1	Lakeville	Monthly NQC - used August for LCR	Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	5.52	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	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market

Major new projects modeled: None

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical overlapping contingency is the outage of the Eagle Rock-Silverado-Fulton 115 kV line and the Cortina #4 230/115 kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60 kV. This limiting contingency establishes a LCR of 217 MW in 2011 (includes 3 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the outage of the Cortina #4 230/115 kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60 kV. This limiting contingency establishes a LCR of 93 MW in 2011 (includes 3 MW of QF/MUNI generation).

Effectiveness factors:

All the units within the Eagle-Rock sub-area are needed therefore no effectiveness factor is needed. Units outside this area are not effective.

Fulton Sub-area

The most critical overlapping contingency is the outage of the Lakeville-Ignacio 230 kV line #1 and the Crocket-Sobrante 230 kV line #1. The sub-area area limitation is thermal overloading of Fulton-Lakeville 230 kV line #1. This limiting contingency establishes a LCR of 546 MW (includes 14 MW of QF and 57 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

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

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

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Lakeville 230 kV line with DEC power plant out of service. The sub-area limitation is thermal overloading of the Vaca Dixon-Tulucay 230 kV. This limiting contingency establishes a LCR of 734 MW (includes 15 MW of QF and 118 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	37
31430	SMUDGE01	1	37
31400	SANTA FE	1	37

31416	GEYSER13	1	37
31424	GEYSER18	1	37
31426	GEYSER20	1	37
38106	NCPA1GY1	1	37
38108	NCPA1GY2	1	37
31421	BOTTLERK	1	35
31404	WEST FOR	2	35
31402	BEAR CAN	1	35
31402	BEAR CAN	2	35
31404	WEST FOR	1	35
31414	GEYSER12	1	35
31418	GEYSER14	1	35
31420	GEYSER16	1	35
31422	GEYSER17	1	35
38110	NCPA2GY1	1	35
38112	NCPA2GY2	1	35
31406	GEYSR5-6	1	19
31406	GEYSR5-6	2	19
31408	GEYSER78	1	19
31408	GEYSER78	2	19
31412	GEYSER11	1	19
31435	GEO.ENGY	1	19
31435	GEO.ENGY	2	19

Changes compared to last year's results:

Overall the load forecast went down by 40 MW and the LCR need down by 56. The study results shown in this report for the overall North Coast and North Bay area assume that DC run-back can be used as a mitigation plan.

North Coast/North Bay Overall Requirements:

2011	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	15	118	728	861

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ¹¹	734	0	734
Category C (Multiple) ¹²	734	0	734

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

¹² Multiple contingencies means that the system will be able to 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.

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) Lodi STIG-Eight Mile Road 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) Drum is in Summit is out
- 7) Spaulding is in Summit is out
- 8) Brighton is in Bellota is out
- 9) Rio Oso is in Lockeford is out
- 10) Gold Hill is in Eight Mile is out
- 11) Lodi STIG is in Eight Mile Road is out
- 12) Gold Hill is in Lake is out

Total 2011 busload within the defined area: 1858 MW with 119 MW of losses resulting in total load + losses of 1977 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	20.78	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	2.44	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
BUCKCK_7_OAKFLT				1.13		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	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	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
DAVIS_7_MNMETH				2.80		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	2.96	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	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	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	Placer, 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	0.50	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	47.91	1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	5.05	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
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				0.05		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	Monthly NQC - used August for LCR	MUNI

						Mountain		
MDFKRL_2_PROJECT	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
MDFKRL_2_PROJECT	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
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	NEWCASTLE	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	OROVILLE	9.1	6.50	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	8.05	1	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	8.05	2	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	2.51	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
PLSNTG_7_LNCLND	32408	PLSNT GR	60	2.10		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	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				0.77		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Drum-Rio Oso, South of Palermo, South of		MUNI

						Table Mountain		
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table Mountain		MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	4.70	3	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	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	4.96	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	9.37	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	21.07	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, 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
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.30		Colgate, South of Table Mountain	Not modeled	Market
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	43.58	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	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. Atlantic-Lincoln 115 kV Transmission Upgrade

3. Colgate 230/60 kV transformer reinforcement
4. Pease-Marysville #2 60 kV Line
5. Palermo 115 kV Circuit Breaker and Switch Replacement

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 in 2011 a LCR of 1510 MW (includes 220 MW of QF and 837 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

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

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	8
31794	WOODLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31888	OROVILLE	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	SPIINCF	1	2
32162	RIV.DLTA	1	2
32510	CHILIBAR	1	2
32514	ELDRADO2	1	2
32513	ELDRADO1	1	2
32478	HALSEY F	1	2
32458	RALSTON	1	2
32456	MIDLFORK	1	2
32456	MIDLFORK	2	2
38114	Stig CC	1	2
32460	NEWCASTLE	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 and Pease-Marysville #2 60 kV line projects.

If any one of these project are delayed all units within this area (Narrows #1 & #2 and Camp Far West) are needed.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Green Leaf II Cogen unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 124 MW (includes 91 MW of QF generation) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Bogue Sub-area

The most critical contingency is the loss of the Pease-Rio Oso 115 kV line with one of the Greenleaf #1 units out of service. The area limitation is thermal overloading of the Palermo-Bogue 115 kV line. This limiting contingency establishes in 2011 a LCR of 137 MW (includes 47 MW of QF generation and 45 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Greenleaf #1 units 1&2 and Feather River EC) are needed therefore no effectiveness factor is required.

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-East Nicolaus 115 kV line. This limiting contingency establishes a LCR of 1630 MW (includes 417 MW of QF and Muni generation as well as

546 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo-Pease 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Palermo-East Nicolaus 115 kV line. This contingency establishes in 2011 a LCR of 1407 MW (includes 417 MW of QF and Muni generation as well as 313 MW of deficiency).

Effectiveness factors:

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

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 116 MW (includes 0 MW of QF and Muni generation as well as 91 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Placer Sub-area

The most critical contingency is the loss of the 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 LCR of 111 MW (includes 0 MW of QF and Muni generation as well as 32 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #2 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 66 MW (includes 0 MW of QF and Muni generation) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Chicago Park, Dutch Flat#1, Wise units 1&2, Newcastle and Halsey) are needed therefore no effectiveness factor is required.

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2011 a LCR of 687 MW (includes 418 MW of QF and Muni generation as well as 12 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2011 a LCR of 296 MW (includes 418 MW of QF and Muni generation).

Effectiveness factors:

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

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Lincoln 115 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 488 MW (includes 343 MW of QF and Muni generation as well as 77 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 473 MW (includes 343 MW of QF and Muni generation as well as 62 MW of deficiency) in 2011.

Effectiveness factors:

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

Changes compared to last year’s results:

Overall the Sierra Area load forecast went down by 149 MW. As such, the existing generation capacity needed is reduced by 207 MW. However, the magnitude of the deficiency has significantly increased along with some of the sub-area LCRs needs (South of Palermo and Bogue sub-areas) because of delay in implementing the Palermo-Rio Oso 115 kV reconductoring project.

Sierra Overall Requirements:

2011	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	220	837	759	1816

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ¹³	1330	313	1643
Category C (Multiple) ¹⁴	1510	572	2082

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

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

4. Stockton Area

Area Definition

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

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

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

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

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

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

The substations that delineate the Lockeford Sub-area are:

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

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

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

The substations that delineate the Weber Sub-area are:

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

Total 2011 busload within the defined area: 1141 MW with 22 MW of losses resulting in total load + losses of 1163 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
COGNAT_1_UNIT	33818	COG.NTNL	12	38.31	1	Weber		QF/Selfgen
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	11.09	1	Tesla-Bellota		MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	3.00	1	Tesla-Bellota		QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.59	1	Tesla-Bellota		Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota		Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	14.66	1	Tesla-Bellota		QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	47.44	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	15.58	1	Tesla-Bellota		QF/Selfgen
VLYHOM_7_SSSJID				1.49		Tesla-Bellota	Not modeled	QF/Selfgen
CAMCHE_1_PL1X3	33850	CAMANACHE	4.2	3.50	1	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANACHE	4.2	3.50	2	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANACHE	4.2	3.50	3	Tesla-Bellota	No NQC - historical data	MUNI
NA	33687	STKTN WW	60	2.00	1	Weber	No NQC - historical data	QF/Selfgen
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - historical data	QF/Selfgen

Major new projects modeled:

1. Tesla 115 kV Capacity Increase

Critical Contingency Analysis Summary

Stockton overall

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 547 MW (includes 83 MW of QF and 118 MW of Muni generation as well as 153 MW of deficiency) in 2011 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 447 MW (includes 83 MW of QF and 118 MW of Muni generation as well as 153 MW of deficiency) in 2011.

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 2011 local capacity need of 394 MW (includes 83 MW of QF and 118 MW of Muni generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the Stanislaus unit #1. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This single contingency establishes a local capacity need of 344 MW (includes 201 MW of QF and Muni generation) in 2011.

Effectiveness factors:

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

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of

the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2011 local capacity need of 63 MW (including 2 MW of QF and 23 MW of Muni generation as well as 38 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Stagg Sub-area

No requirements due to the addition of the addition of the Stagg Under Voltage Load Shedding scheme.

Weber Sub-area

The critical contingency for the Weber area is the loss of the Weber 230/60 kV Transformer #1 with the Cogeneration National out of service. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 72 MW (including 40 MW of QF and Muni generation as well as a deficiency of 32 MW) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency for this sub-area is the loss of Weber 230/60 kV Transformer #1. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 30 MW (including 40 MW of QF and Muni generation) in 2011.

Effectiveness factors:

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

Changes compared to last year's results:

A new Weber sub-area has been added to the Stockton LCR area. Comparing the combined Tesla-Bellota and Lockeford sub-area loads, the load forecast went down by 35 MW. As a combined result of the above changes, the overall Stockton LCR has stayed fairly constant between the years.

Stockton Overall Requirements:

2011	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	126	141	259	526

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ¹⁵	374	0	374
Category C (Multiple) ¹⁶	459	223	682

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-Birds Landing SW Sta 230 kV
- 7) Tesla-Kelso 230 kV
- 8) Tesla-Delta Switching Yard 230 kV
- 9) Tesla-Pittsburg #1 230 kV
- 10) Tesla-Pittsburg #2 230 kV
- 11) Tesla-Newark #1 230 kV
- 12) Tesla-Newark #2 230 kV
- 13) Tesla-Ravenswood 230 kV
- 14) Tesla-Metcalf 500 kV
- 15) Moss Landing-Metcalf 500 kV
- 16) Moss Landing-Metcalf #1 230 kV
- 17) Moss Landing-Metcalf #2 230 kV
- 18) Oakdale TID-Newark #1 115 kV
- 19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

- 1) Lakeville is out Sobrante is in

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

¹⁶ Multiple contingencies means that the system will be able to 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) Ignacio is out Crocket and Sobrante are in
- 3) Parkway is out Moraga is in
- 4) Bahia is out Moraga is in
- 5) Lambie SW Sta is in Vaca Dixon is out
- 6) Peabody is out Birds Landing SW Sta is in
- 7) Tesla and USWP Ralph are out Kelso is in
- 8) Tesla and Altmont Midway are out Delta Switching Yard is in
- 9) Tesla and Tres Vaqueros are out Pittsburg is in
- 10) Tesla and Flowind are out Pittsburg is in
- 11) Tesla is out Newark is in
- 12) Tesla is out Newark and Patterson Pass are in
- 13) Tesla is out Ravenswood is in
- 14) Tesla is out Metcalf is in
- 15) Moss Landing is out Metcalf is in
- 16) Moss Landing is out Metcalf is in
- 17) Moss Landing is out Metcalf is in
- 18) Oakdale TID is out Newark is in
- 19) Oakdale TID is out Newark is in

Total 2011 bus load within the defined area is 9,885 MW with 280 MW of losses and 157 MW of pumps resulting in total load + losses + pumps of 10,322 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	14.00	1	None	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	14.00	2	None	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	14.00	3	None	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	14.00	4	None	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	14.00	5	None	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	14.00	6	None	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	14.00	7	None	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	14.00	8	None	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	15.00	9	None	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	15.00	10	None	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	15.00	11	None	Pumps	MUNI
BLHVN_7_MENLOP				1.51		None	Not modeled	QF/Selfgen
BRDSL_2_HIWIND	32172	HIGHWINDS	34.5	36.54	1	None	Monthly NQC - used August for LCR	Wind
BRDSL_2_SHILO1	32176	SHILOH	34.5	37.36	1	None	Monthly NQC - used August for LCR	Wind
BRDSL_2_SHILO2	32177	SHILO	34.5	35.20	2	None	Monthly NQC - used August for LCR	Wind

CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	26.54	1	San Jose		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.88	1	None		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.88	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	25.80	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	1.54	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33162	DOWCHEM2	13.8	2.03	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33163	DOWCHEM3	13.8	2.03	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	6.93	1	None	Monthly NQC - used August for LCR	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	196.27	1	None		Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	191.36	1	None		Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	191.36	1	None		Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Monthly NQC - used August for LCR	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	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	46.00	1	Llagas	Monthly NQC - used August for LCR	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	26.27	1	None		QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	18.63	1	Pittsburg		QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.78	1	Pittsburg		QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	19.30	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	18.98	1	Pittsburg		QF/Selfgen
HICKS_7_GUADLP				2.07		None	Not modeled	QF/Selfgen
KIRKER_7_KELCVN	32951	KIRKER	115	3.21		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.30		None	Not modeled	Market

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	4.05	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	0.00	1	San Jose		QF/Selfgen
MEDOLN_7_CHEVCP				0.68		Pittsburg	Not modeled	QF/Selfgen
METCLF_1_QF				0.00		None	Not modeled	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1		Monthly NQC - used August for LCR	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1		Monthly NQC - used August for LCR	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1		Monthly NQC - used August for LCR	Market
MILBRA_1_QF				0.00			Not modeled	QF/Selfgen
MISSIX_1_QF				0.03			Not modeled	QF/Selfgen
MLPTAS_7_QFUNTS				0.02		San Jose	Not modeled	QF/Selfgen
MNTAGU_7_NEWBYI				3.62		None	Not modeled	QF/Selfgen
NEWARK_1_QF				0.01		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				0.44		Oakland	Not modeled	MUNI
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market

OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	312.00	1	Pittsburg		Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	317.00	1	Pittsburg		Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	682.00	1	Pittsburg		Market
POTRPP_7_UNIT 3	33252	POTRERO3	20	206.00	1		Retired	Market
POTRPP_7_UNIT 4	33253	POTRERO4	13.8	52.0	1		Retired	Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	52.0	1		Retired	Market
POTRPP_7_UNIT 6	33255	POTRERO6	13.8	52.00	1		Retired	Market
RICHMN_7_BAYENV				2.00		None	Not modeled	QF/Selfgen
RVRVIEW_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	0.34	1	None	Monthly NQC - used August for LCR	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.89	1	None		QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.05	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	12.5	6.44	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	6.44	2	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	6.44	3	Pittsburg		QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	19.00	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.15	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.15	2	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.14	3	Pittsburg		QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	27.45	1	None		QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	11.06	1	None	Monthly NQC - used August for LCR	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	20.31	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.65	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.65	2	None	Monthly NQC - used August for LCR	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	2.41	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	1.30	1	None	Monthly NQC - used August for LCR	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - historical data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - historical data	QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	19.60	1	Pittsburg		QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	39.20	1	Pittsburg		QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	39.20	1	Pittsburg		QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	2.10	1	San Jose	No NQC - historical data	QF/Selfgen

New unit	32171	HIGHWND3	34.5	15.00	1	None	No NQC - estimated data	Wind
----------	-------	----------	------	-------	---	------	-------------------------	------

Major new projects modeled:

1. AHW #1 & #2 115kV Re-Cabling
2. New TransBay DC cable
3. Pittsburg-Tesla 230 kV Lines Reconductoring
4. New Oakland C-X #3 115kV Cable
5. San Mateo – Bay Meadows 115kV #1 & #2 Line Reconductoring

Critical Contingency Analysis Summary

San Francisco Sub-area

By 2011, Potrero units #3, #4, #5 and #6 (360 MW) will no longer be required once the Trans Bay DC cable is operational and re-cabling of the AHW #1 and # 2 115kV cables is complete.

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the Moraga-Claremont 115 kV lines. This limiting contingency establishes a LCR of 46 MW in 2011 (includes 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

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

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-Llagas 115 kV line as well as voltage drop (5%) at the Morgan Hill substation.

As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 112 MW in 2011 (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

San Jose Sub-area

The most critical contingency is an outage of Metcalf-El Patio #1 or #2 115 kV line followed by Metcalf-Evergreen #1 115 kV line. The area limitation is thermal overloading of the Metcalf-Evergreen #2 115 kV line. This limiting contingency establishes a LCR of 516 MW in 2011 (includes 54 MW of QF and 202 MW of Muni generation as well as 74 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	20
36856	CCCA100	1	6
36854	Cogen	1	6
36854	Cogen	2	6
36863	DVRaGT1	1	6
36864	DVRbGT2	1	6
36865	DVRaST3	1	6
35860	OLS-AGNE	1	5
36858	Gia100	1	5
36859	Gia200	2	5
35854	LECEFGT1	1	5
35855	LECEFGT2	2	5
35856	LECEFGT3	3	5
35857	LECEFGT4	4	5

Pittsburg and Oakland Sub-area Combined

The most critical contingency is an outage of the Moraga #3 230/115 kV transformer combined with the loss of Delta Energy Center. The sub-area area limitation is thermal overloading of Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2866 MW in 2011 (including 531 MW of QF/Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Moraga #3 230/115 kV transformer. The sub-area area limitation is thermal overloading of the Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2453 MW in 2011 (including 531 MW of QF/Muni generation).

Effectiveness factors:

Please see Bay Area overall.

Bay Area overall

The most critical contingency is the loss of the Tesla-Metcalf 500 kV followed by Tesla-Newark #1 230 kV line or vice versa. The area limitation is thermal overload of the ADCC-Newark 230 kV section of the Tesla-Newark #2 230 kV line. This limiting contingency establishes a LCR of 4804 MW in 2011 (includes 624 MW of QF, 174 MW of Wind and 412 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Tesla-Metcalf 500 kV followed by Delta Energy Center or vice versa. The area limitation is reactive margin within the Bay Area. This limiting contingency establishes a LCR of 4036 MW in 2011 (includes 624 MW of QF, 174 MW of Wind and 412 MW of Muni generation).

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors 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 46 MW and that drives a small LCR increase. The retirement of Potrero units 3, 4, 5 and 6 drive the rest of the LCR increase because they were the most effective units in mitigating the Tesla-Newark #2 230 kV line and they have to be replaced with less effective units. In the San Jose area there is a new deficiency due mostly to load shifting between substations and the fact that generation in the area is far less effective than the load. All the factors mentioned above have an overall effect of increasing the overall area LCR by 227 MW.

Bay Area Overall Requirements:

2011	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	174	624	412	5296	6506

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ¹⁷	4036	0	4036
Category C (Multiple) ¹⁸	4804	74	4878

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

- 1) Gates-Gregg 230 kV Line
- 2) Gates-McCall 230 kV Line
- 3) Gates #1 230/115 kV Transformer Bank
- 4) Los Banos #3 230/70 kV Transformer Bank
- 5) Los Banos #4 230/70 kV Transformer Bank
- 6) Panoche-Helm 230 kV Line
- 7) Panoche-Kearney 230 kV Line
- 8) Panoche #1 230/115 kV Transformer
- 9) Panoche #2 230/115 kV Transformer
- 10) Warnerville-Wilson 230 kV Line

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

¹⁸ Multiple contingencies means that the system will be able to 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.

- 11) Wilson-Melones 230 kV Line
- 12) Smyrna-Corcoran 115kV Line
- 13) Coalinga #1-San Miguel 70 kV Line

The substations that delineate the Greater Fresno area are:

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

2011 total busload within the defined area is 3212 MW with 94 MW of losses resulting in a total (load plus losses) of 3306 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
AGRICO_6_PL3N5	34608	AGRICO	13.8	16.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00	1	Wilson, Herndon		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	0.93		Wilson	Not modeled	QF/Selfgen
BULLRD_7_SAGNES				0.00		Wilson	Not modeled	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	8.84	1	Wilson		QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.46	2	Wilson		QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	11.25	1	Wilson, Herndon		Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	35.41	1	Wilson		QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	0.98		Wilson	Not modeled	MUNI
CRNEVL_6_CRNVA				0.71		Wilson	Not modeled - Monthly NQC - used August for	Market

							LCR	
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	9.87	1	Wilson, Herndon		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	11.25	1	Wilson		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	3.18	2	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.70	3	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.45	4	Wilson		QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	41.50	1	Wilson		Market
GWFPWR_1_UNITS	34431	GWFPWR_1	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWFPWR_2	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_6_UNIT	34650	GWFPWR_6	9.11	24.57	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	GWFPWR_1	13.8	45.33	1	Wilson, Henrietta		Market
HENRTA_6_UNITA2	34541	GWFPWR_2	13.8	45.23	1	Wilson, Henrietta		Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	2.01	1	Wilson	Monthly NQC - used August for LCR	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	7.85	1	Wilson		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	29.75	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	21.74	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	70.00	1	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	2	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	3	Wilson, Herndon		MUNI
PNCHPP_1_PL1X2	34328	STARGET1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGET2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	40.00	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	42.78	1	Wilson		Market
SGREGY_6_SANGER	34646	SANGERCO	9.11	37.47	1	Wilson		QF/Selfgen
STOREY_7_MDRCHW				0.82		Wilson	Not modeled	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	20.01	1	Wilson, Herndon		QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson		Market
WRGHTP_7_AMENGY				0.60		Wilson	Not modeled	QF/Selfgen
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
MENBIO_6_RENEW1	34339	CALRENEW	12.5	5.00	1	Wilson	No NQC - Pmax	Market
New Unit	34603	JQBSWLT	12.5	3.00	1	Wilson	No NQC - Pmax	Market

Major new projects modeled:

1. Two new small peakers

Critical Contingency Analysis Summary

Wilson Sub-area

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

The most critical contingency is the loss of the Melones - Wilson 230 kV line overlapped with one of the Helms units out of service. This contingency would thermally overload the Warnerville - Wilson 230 kV line (most stringent) and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a LCR of 1997 MW in 2011 (includes

207 MW of QF and 278 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34332	JRWCOGEN	1	40%
34330	ELNIDO	1	37%
34322	MERCEDFL	1	35%
34320	MCSWAIN	1	34%
34306	EXCHQUER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCOGN	1	32%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34631	SJ2GEN	1	28%
34633	SJ3GEN	1	27%
34636	FRIANTDM	2	27%
34636	FRIANTDM	3	27%
34636	FRIANTDM	4	27%
34600	HELMS 1	1	27%
34602	HELMS 2	1	27%
34604	HELMS 3	1	27%
34308	KERCKHOF	1	26%
34344	KERCKHOF	1	26%
34344	KERCKHOF	2	26%
34344	KERCKHOF	3	26%
34485	FRESNOWW	1	24%
34648	DINUBA E	1	22%
34179	MADERA_G	1	22%
34616	KINGSRIV	1	22%
34624	BALCH 1	1	21%
34671	KRCDPCT1	1	21%
34672	KRCDPCT2	1	21%
34640	ULTR.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%
34610	HAAS	1	18%
34610	HAAS	1	18%
34614	BLCH 2-3	1	18%
34612	BLCH 2-2	1	17%
38720	PINE FLT	1	17%
38720	PINE FLT	2	17%
38720	PINE FLT	3	17%

34431	GWF_HEP1	1	17%
34433	GWF_HEP2	1	17%
34334	BIO PWR	1	14%
34608	AGRICO	2	14%
34608	AGRICO	3	14%
34608	AGRICO	4	14%
34539	GWF_GT1	1	14%
34541	GWF_GT2	1	14%
34650	GWF-PWR.	1	13%
34186	DG_PAN1	1	11%
34142	WHD_PAN2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%
34553	WHD_GAT2	1	9%
34654	COLNGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Herndon Sub-area

The most critical contingency is the loss of the Herndon #1 230/115 kV transformer overlapped with Kerckhoff II generator out of service. This contingency could thermally overload the parallel Herndon #2 230/115 kV transformer. This limiting contingency establishes a LCR of 1132 MW (includes 51 MW of QF and 210 MW of Muni generation) in 2011 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 transformer, which could thermally overload the parallel Herndon #2 230/115 kV transformer. This limiting contingency establishes a LCR of 840 MW (includes 51 MW of QF and 210 MW of Muni generation) in 2011.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34308	KERCKHOF	1	34%
34344	KERCKHOF	1	34%
34344	KERCKHOF	2	34%
34344	KERCKHOF	3	34%
34624	BALCH 1	1	33%
34646	SANGERCO	1	31%
34616	KINGSRIV	1	31%

34671	KRCDPCT1	1	31%
34672	KRCDPCT2	1	31%
34640	ULTR.PWR	1	30%
34648	DINUBA E	1	28%
34642	KINGSBUR	1	25%
38720	PINE FLT	1	23%
38720	PINE FLT	2	23%
38720	PINE FLT	3	23%
34610	HAAS	1	23%
34610	HAAS	2	23%
34614	BLCH 2-3	1	23%
34612	BLCH 2-2	1	23%
34431	GWF_HEP1	1	14%
34433	GWF_HEP2	1	14%
34301	CHOWCOGN	1	9%
34305	CHWCHLA2	1	9%
34608	AGRICO	2	7%
34608	AGRICO	3	7%
34608	AGRICO	4	7%
34332	JRWCOGEN	1	-6%
34600	HELMS 1	1	-12%
34602	HELMS 2	1	-12%
34604	HELMS 3	1	-12%
34485	FRESNOWW	1	-14%

Henrietta Sub-area

The two most critical contingencies listed below together establish a local capacity need of 57 MW (includes 25 MW of QF as well as 4 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 28 MW in 2011 (includes 0 MW of QF generation).

The second most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV line. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 29 MW in 2011 (includes 25 MW of QF generation as well as 4 MW of deficiency).

The most critical single contingency is the loss of Henrietta 230/70 kV transformer bank #4. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 28 MW in 2011 (includes 25 MW of QF generation).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast is steady (down by 71 MW). Path 15 flow is 1275 MW N-S the same as last year. Due to small re-dispatch between sub-areas the total overall effect is that LCR has decreased by 200 MW.

Fresno Area Overall Requirements:

2011	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	207	278	2434	2919

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ¹⁹	2200	0	2200
Category C (Multiple) ²⁰	2444	4	2448

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

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

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

- 5) Midway 230/115 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 kV is out Kern PP 115 kV is in
- 3) Kern PP 230 kV is out Kern PP 115 kV is in
- 4) Kern PP 230 kV is out Kern PP 115 kV is in
- 5) Midway 230 kV is out Midway 115 kV is in
- 6) Midway 230 kV is out Midway 115 kV is in
- 7) Midway 230 kV is out Midway 115 kV is in
- 8) Temblor is in San Luis Obispo is out

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

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

The substations that delineate the Weedpatch sub-area are:

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

2011 total busload within the defined area: 1370 MW with 16 MW of losses resulting in a total (load plus losses) of 1387 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BDGRCK_1_UNITS	35029	BADGERCK	9.11	41.98	1	Kern PP		QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	44.41	1	Kern PP		QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	43.74	1	Kern PP		QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	0.43	1	Kern PP		QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	5.53	1	Kern PP		QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	29.28	1	Kern PP		QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVERY	9.11	3.02	1	Kern PP		QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	46.58	1	Kern PP		QF/Selfgen
FELLOW_7_QFUNTS				2.17		Kern PP	Not modeled	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.09	1	Kern PP		QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	45.53	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	27.29	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	27.91	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				8.82		Kern PP	Not modeled	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.18	1	Kern PP		QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	34.33	1	Kern PP		QF/Selfgen

MIDWAY_1_QF				0.02		Kern PP	Not modeled	QF/Selfgen
MKTRCK_1_UNIT_1	35060	PSEMCKIT	9.11	43.92	1	Kern PP		QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	50.33	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	39.68	1	Kern PP		QF/Selfgen
RIOBRV_6_UNIT_1	35020	RIOBRAVO	9.11	8.46	1	Weedpatch		QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	45.80	1	Kern PP		QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	8.86	1	Kern PP		QF/Selfgen
TEMBLR_7_WELLPT				0.36		Kern PP	Not modeled	QF/Selfgen
TXMCKT_6_UNIT				3.44		Kern PP	Not modeled	QF/Selfgen
TXNMID_1_UNIT_2	34783	TEXCO NM	9.11	0.01	1	Kern PP		QF/Selfgen
TXNMID_1_UNIT_2	34783	TEXCO NM	9.11	0.01	2	Kern PP		QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.70	1	Kern PP		QF/Selfgen
UNVRSY_1_UNIT_1	35037	UNIVRSTY	9.11	33.36	1	Kern PP		QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	15.95	1	Kern PP		QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	0.00	1	Kern PP	Retired	Market
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 is the outage of the Kern PP #5 230/115 kV transformer bank followed by the Kern PP – Kern Front 115 kV line, which could thermally overload the parallel Kern PP #3 and #3a 230/115 kV transformers. This limiting contingency establishes a LCR of 416 MW in 2011 (includes 691 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of Kern PP #5 230/115 kV transformer bank, which could thermally overload the parallel Kern PP #3 and #3a 230/115 kV transformers. This limiting contingency establishes a LCR of 243 MW in 2011 (includes 691 MW of QF generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35066	PSE-BEAR	1	22%
35029	BADGERCK	1	22%
35023	DOUBLE C	1	22%
35027	HISIERRA	1	22%

35026	KERNFRNT	1	21%
35058	PSE-LVOK	1	21%
35028	OILDALE	1	21%
35062	DISCOVERY	1	21%
35046	SEKR	1	21%
35024	DEXEL +	1	21%
35036	MT POSO	1	15%
35035	ULTR PWR	1	15%
35052	CHEV.USA	1	6%

Weedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line followed by the Wheeler Ridge – Tejon 70 kV line, which could thermally overload the Wheeler Ridge – Weedpatch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a LCR of 31 MW in 2011 (includes 8 MW of QF generation and 13 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 147 MW and that drives the LCR up by 43 MW. The resources in this area are more effective in mitigating the constraint than the overall effect of the load increase.

Kern Area Overall Requirements:

2011	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	699	9	708

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ²¹	243	0	243
Category C (Multiple) ²²	434	13	447

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

²² Multiple contingencies means that the system will be able to survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

8. LA Basin Area

Area Definition

The transmission tie lines into the LA Basin Area are:

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

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

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

Total 2011 busload within the defined area is 19,715 MW with 486 MW of losses and 22 MW pumps resulting in total load + losses + pumps of 20,223 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	62.72	1	Western		QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	62.72	2	Western		QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	62.72	3	Western		QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	62.72	4	Western		QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	31.37	5	Western		QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	31.37	6	Western		QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6 PEAKER	28309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	28007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.14	W5	Eastern		Wind
CABZON_1_WINDA1	28280	CABAZON	33	9.66	1	Eastern	Monthly NQC - used August for LCR	Wind
CENTER_2_QF	24203	CENTER S	66	25.28		Western	Not Modeled	QF/Selfgen
CENTER_2 RHONDO	24203	CENTER S	66	1.91		Western	Not Modeled	QF/Selfgen
CENTER_6 PEAKER	28308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4				36.00		Eastern	Not Modeled	Market
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	1.58	1	Western, El Nido		QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	1.61	2	Western, El Nido		QF/Selfgen
CHINO_2_QF	24024	CHINO	66	10.26		Western	Not modeled	QF/Selfgen
CHINO_6 CIMGEN	24026	CIMGEN	13.8	25.89	1	Western		QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	39.08	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		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
DEVERS_1_QF	25645	VENWIND	115	1.19	EU	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.31	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.44	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.36	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	1.96	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.06	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.46	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.79	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.21	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	24815	GARNET	115	5.23	QF	Eastern	Monthly NQC - used August for	QF/Selfgen

							LCR	
DEVERS_1_QF	25632	TERAWND	115	1.58	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	1.40	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.20	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	2.81	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	1.89	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	2.10	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.63	W1	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				36.00		Eastern	Not modeled	Market
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	48.64	1	Eastern		MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	48.64	2	Eastern		MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	64.86	3	Eastern		MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	64.86	4	Eastern		MUNI
ELLIS_2_QF	24197	ELLIS	66	0.29		Western	Not modeled	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.61		Eastern	Not modeled	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	17.66		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	21.19	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	0.53	G1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.19	G2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.38	G3	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.19	PC	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.61	W2	Eastern	Monthly NQC - used August for LCR	Wind
GARNET_1_WIND	24815	GARNET	115	0.61	W3	Eastern	Monthly NQC - used August for LCR	Wind
GLNARM_7_UNIT 1	28005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	28006	PASADNA2	13.8	22.30	1	Western		MUNI

GLNARM_7_UNIT 3	28005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBN	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	28.10	1	Western		QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	225.00	3	Western, Ellis		Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	227.00	4	Western, Ellis		Market
INDIGO_1_UNIT 1	28190	WINTECX2	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 2	28191	WINTECX1	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 3	28180	WINTECX8	13.8	42.00	1	Eastern		Market
INLDEM_5_UNIT 1	28041	IEEC-G1	19.5	335.00	1	Eastern		Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western	Not Modeled	QF/Selfgen
LACIEN_2_VENICE	24208	LCIENEGA	66	3.68		Western	Not modeled	QF/Selfgen
LAFRES_6_QF	24073	LA FRESA	66	3.28		Western	Not modeled	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.92		Western	Not modeled	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	48.09	1	Western		QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.92		Western	Not modeled	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.17		Western	Not modeled	QF/Selfgen
MIRLOM_2_CORONA				1.94		Eastern	Not modeled	QF/Selfgen
MIRLOM_2_TEMESC				2.18		Eastern	Not modeled	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	39.68	1	Eastern		QF/Selfgen
MIRLOM_6_PEAKE	28307	MRLPKGEN	13.8	43.18	1	Eastern		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.30		Eastern	Not modeled	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	1	Eastern		Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	2	Eastern		Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	3	Eastern		Market
MTWIND_1_UNIT 1				5.35		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 2				2.36		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 3				2.64		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	3.39	1	Western		QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.90		Western	Not modeled	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	1.04		Eastern	Not modeled	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	5.70		Eastern	Not modeled	MUNI
PADUA_6_QF	24111	PADUA	66	4.46		Eastern	Not modeled	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern	Not modeled Monthly NQC - used August for LCR	QF/Selfgen

PWEST_1_UNIT				0.27		Western	Not modeled	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	493.24	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	1.27		Western	Not modeled	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	4.00		Western	Not modeled	Market
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	9.99	1	Western, Ellis		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	0.16		Eastern	Not modeled	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.73		Eastern	Not modeled	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	2.23		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
TIFFNY_1_DILLON				7.72		Western	Not modeled	Wind
VALLEY_2_QF	24160	VALLEYSC	115	4.71		Eastern	Not modeled	QF/Selfgen
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern	Not modeled	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	3.00		Eastern	Not modeled	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	1.30		Eastern	Not modeled	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	3.74		Eastern	Not modeled	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	3.90		Western	Not modeled	MUNI
VISTA_6_QF	24902	VSTA	66	0.13	1	Eastern		QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.00	1	Western		QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	1.96		Western	Not modeled	Market
WALNUT_7_WCOVST	24157	WALNUT	66	3.19		Western	Not modeled	Market
WHTWTR_1_WINDA1	28061	WHITEWTR	33	7.06	1	Eastern	Monthly NQC - used August for LCR	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	35.00	1	Western	No NQC - historical data	Market
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
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	45.00	1	Western, El Nido	No NQC - historical data	QF/Selfgen
NA	24325	ORCOGEN	13.8	12.00	1	Western, Ellis	No NQC - Pmax	QF/Selfgen
NA	24327	THUMSGEN	13.8	49.00	1	Western	No NQC - Pmax	QF/Selfgen
NA	24330	OUTFALL1	13.8	17.00	1	Western, El Nido	No NQC - Pmax	QF/Selfgen
NA	24331	OUTFALL2	13.8	17.00	1	Western, El Nido	No NQC - Pmax	QF/Selfgen
NA	24337	VENICE	13.8	10.10	1	Western, El Nido	No NQC - Pmax	QF/Selfgen

NA	24341	COYGEN	13.8	20.00	1	Western, Ellis	No NQC - Pmax	QF/Selfgen
NA	24342	FEDGEN	13.8	24.70	1	Western	No NQC - Pmax	QF/Selfgen
NA	25303	CLTNAGUA	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	28020	WINTEC6	115	0.00	1	Eastern	No NQC - historical data	Wind
NA	28023	WINTEC4	12	0.00	1	Eastern	No NQC - historical data	Wind
NA	28260	ALTAMSA4	115	0.00	1	Eastern	No NQC - historical data	Wind
NA	28951	REFUSE	13.8	12.00	1	Western	No NQC - Pmax	QF/Selfgen
NA	28953	SIGGEN	13.8	29.00	1	Western	No NQC - Pmax	QF/Selfgen
NA	29338	CLEARGEN	13.8	32.00	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	29339	DELGEN	13.8	42.00	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	24324	SANIGEN	13.8	8.00	D1	Eastern	No NQC - Pmax	QF/Selfgen
NA	24332	PALOGEN	13.8	13.00	D1	Western, El Nido	No NQC - Pmax	QF/Selfgen
NA	28060	SEAWEST	115	0.00	S1	Eastern	No NQC - historical data	Wind
NA	28060	SEAWEST	115	0.00	S2	Eastern	No NQC - historical data	Wind
NA	28060	SEAWEST	115	0.00	S3	Eastern	No NQC - historical data	Wind
INLDEM_5_UNIT 2	28042	IEEC-G2	19.5	336.70	1	Eastern	No NQC - Pmax	Market

Major new projects modeled:

1. 15 small existing resources have been modeled
2. As a part of TRTP project the existing Antelope-Mesa Cal 230 kV line will be permanently removed from service in 2011, to make room for a new 500 kV line

Critical Contingency Analysis Summary

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one Songs unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,589 MW in 2011 (includes 1127 MW of QF, 36 MW of Wind, 797 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff. Fact (%)
24052	MTNVIST3	3	34
24053	MTNVIST4	4	34
24071	INLAND	1	33
25422	ETI MWDG	1	33
29305	ETWPKGEN	1	33
24905	RVCANAL1	R1	26
24906	RVCANAL2	R2	26
24907	RVCANAL3	R3	26
24908	RVCANAL4	R4	26
24921	MNTV-CT1	1	26
24922	MNTV-CT2	1	26
24923	MNTV-ST1	1	26
24924	MNTV-CT3	1	26
24925	MNTV-CT4	1	26
24926	MNTV-ST2	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24244	SPRINGEN	1	26
25301	CLTNDREW	1	26
25302	CLTNCTRY	1	26
25303	CLTNAGUA	1	26
25603	DVLCYN3G	3	25
25604	DVLCYN4G	4	25
25648	DVLCYN1G	1	24
25649	DVLCYN2G	2	24
29041	IIEEC-G1	1	24
29042	IIEEC-G2	2	24
25203	ANAHEIMG	1	22
25632	TERAWND	QF	22
25634	BUCKWND	QF	22
25635	ALTWIND	Q1	22
25635	ALTWIND	Q2	22
25637	TRANWND	QF	22
25639	SEAWIND	QF	22
25640	PANAERO	QF	22
25645	VENWIND	EU	22
25645	VENWIND	Q2	22
25645	VENWIND	Q1	22
25646	SANWIND	Q2	22
29190	WINTECX2	1	22
29191	WINTECX1	1	22
29180	WINTEC8	1	22

24815	GARNET	QF	22
24815	GARNET	W3	22
24815	GARNET	W2	22
29023	WINTEC4	1	22
29060	SEAWEST	S1	22
29060	SEAWEST	S3	22
29060	SEAWEST	S2	22
29260	ALTAMSA4	1	22
29290	CABAZON	1	22
29021	WINTEC6	1	22
25657	MJVSPHN1	1	22
25658	MJVSPHN2	2	22
25659	MJVSPHN3	3	22
24030	DELGEN	1	21
25633	CAPWIND	QF	21
29061	WHITEWTR	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29309	BARPKGEN	1	20
29307	MRLPKGEN	1	19
29338	CLEARGEN	1	19
29339	DELGEN	1	19
24066	HUNT1 G	1	18
24067	HUNT2 G	2	18
24167	HUNT3 G	3	18
24168	HUNT4 G	4	18
24129	S.ONOFR2	2	18
24130	S.ONOFR3	3	18
24133	SANTIAGO	1	18
24325	ORCOGEN	1	18
24341	COYGEN	1	18
24001	ALAMT1 G	1	17
24002	ALAMT2 G	2	17
24003	ALAMT3 G	3	17
24004	ALAMT4 G	4	17
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	16
29209	BLY1ST1	1	15
29207	BLY1CT1	1	15
29208	BLY1CT2	1	15
29953	SIGGEN	D1	15

24018	BRIGEN	1	14
24020	CARBGEN1	1	14
24064	HINSON	1	14
24070	ICEGEN	D1	14
24170	LBEACH12	2	14
24171	LBEACH34	3	14
24079	LBEACH7G	7	14
24080	LBEACH8G	8	14
24081	LBEACH9G	9	14
24062	HARBOR G	1	14
25510	HARBORG4	LP	14
24062	HARBOR G	HP	14
29308	CTRPGEN	1	14
24139	SERRFGEN	D1	14
24170	LBEACH12	1	14
24171	LBEACH34	4	14
24173	LBEACH5G	R5	14
24174	LBEACH6G	R6	14
24327	THUMSGEN	1	14
24328	CARBGEN2	1	14
24337	VENICE	1	14
24011	ARCO 1G	1	13
24012	ARCO 2G	2	13
24013	ARCO 3G	3	13
24014	ARCO 4G	4	13
24163	ARCO 5G	5	13
24164	ARCO 6G	6	13
24022	CHEVGEN1	1	13
24023	CHEVGEN2	2	13
24047	ELSEG3 G	3	13
24048	ELSEG4 G	4	13
24094	MOBGEN1	1	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
24329	MOBGEN2	1	13
24330	OUTFALL1	1	13
24331	OUTFALL2	1	13
24332	PALOGEN	D1	13
24333	REDON1 G	R1	13
24334	REDON2 G	R2	13
24335	REDON3 G	R3	13

24336	REDON4 G	R4	13
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29951	REFUSE	D1	11
24342	FEDGEN	1	11
29007	BRODWYSC	1	9
29005	PASADNA1	1	8
29006	PASADNA2	1	8

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park #1 or #2 230 kV line. This limiting contingency establishes a LCR of 5828 MW (which includes 828 MW of QF, 8 MW of Wind, 392 MW of Muni and 2246 MW of nuclear generation) in 2011 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

There are numerous (about 40) other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area and have slightly less LCR need. As such, anyone of them (combination of contingencies) could become binding for any given set of procured resources. As a result, effectiveness factors are not given since they would most likely not facilitate more informed procurement.

Ellis sub-area

The most critical contingency for the Ellis sub-area is the loss of the Barre to Ellis 230 kV line followed by the loss of the Santiago to S.Onofre #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 492 MW in 2011 (which includes 32 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

El Nido sub-area

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

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

These two limiting contingencies establish a LCR of 360 MW in 2011 (which includes 105 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

Changes compared to last year’s results:

Overall the load forecast went up by 165 MW resulting in an increase in LCR. 15 existing small resources (previously not modeled) have been added to the base case. The Ellis and El Nido sub-areas have been added. As a part of TRTP project the existing Antelope-Mesa Cal 230 kV line will be permanently removed from service in 2011, in order to make room for a new 500 kV line, which cause the LCR needs in Western sub-area and LA Basin overall to increase. The combination of these facts has resulted in a total LCR increase of 854 MW.

LA Basin Overall Requirements:

2011	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1163	797	2246	8103	12309

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ²³	10,589	0	10,589
Category C (Multiple) ²⁴	10,589	0	10,589

9. Big Creek/Ventura Area

Area Definition

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

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

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

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

Total 2011 busload within the defined area is 4,295 MW with 90 MW of losses and 263 MW of pumps resulting in total load + losses + pumps of 4648 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek		Market
ANTLPE_2_QF	24457	ARBWIND	66	3.13	1	Big Creek	Monthly NQC - used August for LCR	Wind

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

²⁴ Multiple contingencies means that the system will be able to 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.

ANTLPE_2_QF	24458	ENCANWND	66	16.20	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24459	FLOWIND	66	5.86	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	2.01	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24465	MORWIND	66	8.04	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24491	OAKWIND	66	2.58	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28501	MIDWIND	12	2.58	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	0.95	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28503	NORTHWND	12	2.78	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	1.89	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	1.84	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.65	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.15	1	Big Creek	Monthly NQC - used August for LCR	Wind
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal		Market

BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal		Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	10.57	1	Big Creek		MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	10.57	2	Big Creek		MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	10.57	3	Big Creek		MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	10.57	4	Big Creek		MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	10.57	5	Big Creek		MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	10.57	6	Big Creek		MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	10.57	7	Big Creek		MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	10.57	8	Big Creek		MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	10.57	9	Big Creek		MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	10.57	10	Big Creek		MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	10.57	11	Big Creek		MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	10.57	12	Big Creek		MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	10.57	13	Big Creek		MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	10.57	14	Big Creek		MUNI

GOLETA_2_QF	24057	GOLETA	66	0.40		Ventura, S.Clara, Moorpark	Not modeled	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	0.65		Ventura, S.Clara, Moorpark	Not modeled	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	9.90		Ventura, S.Clara, Moorpark	Not modeled	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.80		Ventura, S.Clara, Moorpark	Not modeled	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	22.69	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	28054	PSTRIAG3	18	157.90	G3	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	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, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MONLTH_6_BOREL	24456	BOREL	66	9.05	1	Big Creek		QF/Selfgen
MOORPK_6_QF	24098	MOORPARK	66	27.52		Ventura, Moorpark	Not modeled	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	2.49		Ventura, Moorpark	Not modeled	QF/Selfgen
OMAR_2_UNITS	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	1	Big Creek		MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	2	Big Creek		MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	3	Big Creek		MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	4	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	5	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	6	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	7	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	8	Big Creek		MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	18.18	1	Big Creek,		QF/Selfgen

						Vestal		
PANDOL_6_UNIT	24113	PANDOL	13.8	14.82	2	Big Creek, Vestal		QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	0.78		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	1.41		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_QF	24212	RECTOR	66	10.23		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	1.60		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_6_MWDFTH	24135	SAUGUS	66	6.50		Big Creek	Not modeled	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	21.54	1	Big Creek		MUNI
SAUGUS_6_QF	24135	SAUGUS	66	2.72		Big Creek	Not modeled	QF/Selfgen
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.70		Big Creek	Not modeled	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	46.38	1	Ventura, S.Clara, Moorpark		QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	45.37	1	Ventura, S.Clara, Moorpark		Market
SNCLRA_6_QF	24127	S.CLARA	66	2.04	1	Ventura, S.Clara, Moorpark		QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	14.20	1	Ventura, S.Clara, Moorpark		QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.52		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	0.52		Big Creek, Rector, Vestal	Not modeled	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	69.73	1	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	69.73	2	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	69.73	3	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	69.74	4	Big Creek		QF/Selfgen
TENGEN_6_UNIT 1	24148	TENNGEN1	13.8	19.93	1	Big Creek		Market
TENGEN_6_UNIT 2	24149	TENNGEN2	13.8	17.50	2	Big Creek		Market
VESTAL_2_KERN	24152	VESTAL	66	4.17	1	Big Creek, Vestal		QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	1.97		Big Creek, Vestal	Not modeled	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.98	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	38.00	1	Big Creek		Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek		Market
MNDALY_6_MCGRTH	28306	MCGPKGEN	13.8	47.20	1	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market

NA	23370	KAWGEN	13.8	18.00	1	Big Creek, Rector, Vestal	No NQC - Pmax	QF/Selfgen
NA	24340	CHARMIN	13.8	20.40	1	Ventura, S. Clara, Moorpark	No NQC - Pmax	QF/Selfgen
NA	24372	KR 3-1	13.8	22.80	1	Big Creek, Vestal	No NQC - Pmax	QF/Selfgen
NA	24373	KR 3-2	13.8	21.50	1	Big Creek, Vestal	No NQC - Pmax	QF/Selfgen
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, S. Clara, Moorpark	No NQC - Pmax	QF/Selfgen
NA	24362	Exgen2	13.8	29.00	G1	Ventura, S. Clara, Moorpark	No NQC - Pmax	QF/Selfgen
NA	24326	Exgen1	13.8	20.00	S1	Ventura, S. Clara, Moorpark	No NQC - Pmax	QF/Selfgen

Major new projects modeled:

1. Antelope Transmission Project (Segments 1, 2 and 3)
2. 6 small existing resources have been modeled

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The most critical contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee #1 or #2 230 kV line. This limiting contingency establishes a LCR of 2786 MW in 2011 (includes 962 MW of QF, 184 MW of Muni and 50 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The second most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee #1 or #2 230 kV line. This limiting contingency establishes a LCR of 2727 MW in 2011 (includes 962 MW of QF, 184 MW of Muni and 50 MW of Wind generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff. Fctr. (%)
24009	APPGEN1G	1	29
24010	APPGEN2G	2	29
24107	ORMOND1G	1	29
24108	ORMOND2G	2	29
24118	PITCHGEN	1	28
24148	TENNGEN1	1	28
24149	TENNGEN2	2	28
24089	MANDLY1G	1	27
24090	MANDLY2G	2	27
24110	OXGEN	1	27
24119	PROCGEN	1	27
24159	WILLAMET	1	27
25651	WARNE1	1	27
25652	WARNE2	1	27
28004	ELLWOOD	1	27
24361	EXGEN1	1	27
24362	EXGEN2	2	27
28051	PSTRIAG1	G1	26
25606	EDMON2AP	2	26
25607	EDMON3AP	3	26
25607	EDMON3AP	4	26
25608	EDMON4AP	5	26
25608	EDMON4AP	6	26
25609	EDMON5AP	7	26
25609	EDMON5AP	8	26
25610	EDMON6AP	9	26
25610	EDMON6AP	10	26
25611	EDMON7AP	11	26
25611	EDMON7AP	12	26
25612	EDMON8AP	13	26
25612	EDMON8AP	14	26
28054	PSTRIAG3	G3	25
25615	OSO B P	7	25
25615	OSO B P	8	25
28952	CAMGEN	13.8	25
24127	S.CLARA	1	25
24340	CHARMIN	1	25
28055	PSTRIAS2	S2	24
28053	PSTRIAS1	S1	24
28052	PSTRIAG2	G2	24
25605	EDMON1AP	1	24
24143	SYCCYN1G	1	24

24144	SYCCYN2G	2	24
24145	SYCCYN3G	3	24
24146	SYCCYN4G	4	24
24102	OMAR 1G	1	23
24103	OMAR 2G	2	23
24104	OMAR 3G	3	23
24105	OMAR 4G	4	23
25614	OSO A P	1	23
25614	OSO A P	2	23
25653	ALAMO SC	1	23
24222	MANDLY3G	3	20
28008	LAKEGEN	1	20
24150	ULTRAGEN	1	20
24152	VESTAL	1	20
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	20
24306	B CRK1-1	1	20
24306	B CRK1-1	2	20
24307	B CRK1-2	3	20
24307	B CRK1-2	4	20
24308	B CRK2-1	1	20
24308	B CRK2-1	2	20
24309	B CRK2-2	3	20
24309	B CRK2-2	4	20
24310	B CRK2-3	5	20
24310	B CRK2-3	6	20
24311	B CRK3-1	1	20
24311	B CRK3-1	2	20
24312	B CRK3-2	3	20
24312	B CRK3-2	4	20
24313	B CRK3-3	5	20
24314	B CRK 4	41	20
24314	B CRK 4	42	20
24315	B CRK 8	81	20
24315	B CRK 8	82	20
24317	MAMOTH1G	1	20
24318	MAMOTH2G	2	20
24113	PANDOL	1	19
24113	PANDOL	2	19
24437	KERNRVR	1	18
24459	FLOWIND	1	14
24436	GOLDTOWN	1	14
28501	MIDWIND	1	14
24457	ARBWIND	1	13
24456	BOREL	1	12
24458	ENCANWND	1	12
24460	DUTCHWND	1	12
24465	MORWIND	1	12

28503	NORTHWND	1	12
28504	ZONDWND1	1	12
28505	ZONDWND2	1	12
25618	PEARBMBP	5	6
25618	PEARBMBP	6	6
25619	PEARBMCP	7	6
25619	PEARBMCP	8	6
25617	PEARBMAP	1	5
25617	PEARBMAP	2	5
25620	PEARBMDP	9	5
24136	SEAWEST	1	5

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 641 MW (includes 30 MW of QF generation) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
24370	KAWGEN	1	45
24319	EASTWOOD	1	41
24306	B CRK1-1	1	41
24306	B CRK1-1	2	41
24307	B CRK1-2	3	41
24307	B CRK1-2	4	41
24323	PORTAL	1	41
24308	B CRK2-1	1	40
24308	B CRK2-1	2	40
24309	B CRK2-2	3	40
24309	B CRK2-2	4	40
24315	B CRK 8	81	40
24315	B CRK 8	82	40
24310	B CRK2-3	5	39
24310	B CRK2-3	6	39
24311	B CRK3-1	1	39
24311	B CRK3-1	2	39
24312	B CRK3-2	3	39
24312	B CRK3-2	4	39
24313	B CRK3-3	5	39
24317	MAMOTH1G	1	39
24318	MAMOTH2G	2	39

24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 854 MW in 2011 (which includes 156 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
28008	LAKEGEN	1	46
24113	PANDOL	1	45
24113	PANDOL	2	45
24150	ULTRAGEN	1	45
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24152	VESTAL	1	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	24
24306	B CRK1-1	1	24
24306	B CRK1-1	2	24
24307	B CRK1-2	3	24
24307	B CRK1-2	4	24
24308	B CRK2-1	1	24
24308	B CRK2-1	2	24
24309	B CRK2-2	3	24
24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24
24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23

24314	B CRK 4	41	22
24314	B CRK 4	42	22

S. Clara sub-areas

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 346 MW in 2011 (which includes 171 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

Moorpark sub-areas

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 606 MW in 2011 (which includes 201 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

Changes compared to last year's results:

Overall the load forecast went down by 385 MW. 6 existing small resources (previously not modeled) have been added to the base case. The Santa Clara and Moorpark sub-areas have been added. The transmission boundary has changed slightly due removal and addition of transmission projects required under TRTP; without impact to the amount of load or resources in this local area. The overall effect is that the LCR has decreased by 607 MW.

Big Creek Overall Requirements:

2011	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1012	184	4110	5306

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ²⁵	2786	0	2786
Category C (Multiple) ²⁶	2786	0	2786

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

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

Total 2011 busload within the defined area: 4920 MW with 116 MW of losses resulting in total load + losses of 5036 MW.

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

²⁶ Multiple contingencies means that the system will be able to 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	None		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.12	1	None		QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.92	1	None		QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.52	1	None		QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	2.00	2	None		QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	6.10	1	None		QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	6.33	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	1.00	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	16.00	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
ESCND0_6_PL1X2	22257	MMC_ES	13.8	35.50	1	None		Market
ESCND0_6_UNITB1	22153	CALPK_ES	13.8	45.50	1	None		Market
ESCO_6_GLMQF	22332	GOALLINE	69	47.39	1	Escondido		QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	16.00	1	None		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	1	None		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	15.02	1	None		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	2	None		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	13.95	2	None		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.98	1	None		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	1	None		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	16.05	2	None		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	2	None		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	None		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	None		Market
MRGT_6_MEF2	22487	MFE_MR2	13.8	47.90	1	None	No NQC - Pmax	Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	46.60	1	None		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	18.55	1	None		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.45	2	None		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.00	1	None		QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.90	1	None		QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	35.84	1	None		QF/Selfgen
OTAY_6_PL1X2	22617	MMC_OY	13.8	35.50	1	None		Market
OTAY_6_UNITB1	22604	OTAY	69	1.50	1	None		QF/Selfgen
OTAY_6_UNITB1	22604	OTAY	69	1.49	2	None		QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	3.75	3	None		QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1	None		Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1	None		Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1	None		Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.17	1	None		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.17	1	None		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.66	1	None		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.16	2	None		QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	22.28	1	None		QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	4.02	1	None		QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.75	1	None		QF/Selfgen

SOBAY_7_GT1	22776	SOUTHBGT	12.5	15.00	1	None		Market
SOBAY_7_SY1	22780	SOUTHBY1	15	146.00	1	None		Market
SOBAY_7_SY2	22784	SOUTHBY2	15	149.60	1	None		Market
KYCORA_7_UNIT 1	22384	KYOCERA	69	0.00	1	None	No NQC - historical data	QF/Selfgen
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	22760	SHADOWR	138	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
NA	22680	R.SNTAFE	69	0.30	2	None	No NQC - historical data	QF/Selfgen
ELCAJN_6_LM6K	23320	C509	13.8	49.90	1	El Cajon	No NQC - Pmax	Market
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	Bernardo	No NQC - Pmax	Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	Bernardo	No NQC - Pmax	Market
New unit	23120	BULLMOOS	13.8	27.00	1	None	No NQC - Pmax	Market
OGROVE_6_PL1X2	22628	PA99MWQ1	13.8	47.00	1	Pala	No NQC - Pmax	Market
OGROVE_6_PL1X2	22629	PA99MWQ2	13.8	47.00	2	Pala	No NQC - Pmax	Market

Major new projects modeled:

1. Otay Mesa Power Plant (603 MW)
2. New peaker at Miramar 69 kV substation (47.9 MW)
3. New biomass unit at Border 69 kV substation (27 MW) and its associated transmission upgrade, reconductor TL649A, Otay-Otay Lakes Tap 69kV
4. New peaker units at Pala 69 kV substation (94 MW)
5. New peaker unit at El Cajon 69kV substation (49 MW)
6. New generating units at Escondido 69kV (40 MW)
7. Transmission project to reconductor TL6927, Eastgate-Rose Canyon 69kV
8. New and/or upgrade of 69kV capacitors at Lilac, Rincon, Santa Ysabel and Warners 69kV substation
9. Advancement of Sunrise capacitors at South Bay 69kV and San Luis Rey 230kV substations
10. TL13802D, Encina-Calavera Tap 138 kV project: Upgrade and re-arrange Cannon-Calavera Tap (TL13802D) to create two new 138kV transmission lines: Encina-Calavera Tap-Shadow ridge (274mva) and Cannon-Calavera Tap-San Luis Rey (204mva); re-energize existing Escondido Bank 50

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 would thermally overload the Garfield-Murray 69 kV line. This limiting contingency establishes a LCR of 66 MW (including 0 MW of QF generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Rose Canyon Sub-area

This sub-area has been eliminated due to recently approved transmission project, TL6927, Eastgate-Rose Canyon 69 kV reconductor.

Bernardo Sub-area:

The most critical contingency for the Bernardo sub-area is the loss of Artesian - Sycamore 69 kV line followed by the loss of Poway-Rancho Carmel 69 kV line, which would thermally overload the Felicita Tap-Bernardo 69 kV line. This limiting contingency establishes a LCR of 66 MW (including 0 MW of QF generation and 26 MW of deficiency) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Border 69 kV Sub-area

Sub-area eliminated due to new generation project upgrade, reconductor TL649A, Otay-Otay Lakes Tap 69 kV.

If the project reconductoring is delayed beyond June 1, 2011, the most critical contingency for the Border sub area will be the loss of Border – Miguel 69 kV line (TL6910) followed by the loss of Imperial Beach-Otay-San Ysidro 69 kV line (TL623), which would thermally overload Otay-Otay Lake Tap (TL649). This limiting contingency would establish a local capacity need of 31 MW (includes 0 MW of QF generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:

If the reconductoring project is completed by June 1, 2011, no units will be needed. If the project is not completed, Border Cal Peak, Larkspur and Bullmoose all have the same effectiveness factor.

Escondido Sub-area

The most critical contingency for the Escondido sub-area is the loss of Poway-Pomerado 69 kV line followed by the loss of Bernardo-Rancho Carmel 69kV line which would thermally overload the Esco-Escondido 69 kV line. This limiting contingency establishes a LCR of 82 MW (including 47 MW of QF generation and 35 MW of deficiency) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Escondido sub-area is the loss of Poway-Pomerado 69 kV line which would thermally overload the Esco-Escondido 69 kV line. This limiting contingency establishes a LCR of 10 MW (including 47 MW of QF generation) in 2011 within this sub-area.

Effectiveness factors:

All units within this sub-area (Goal line) are needed so no effectiveness factor is required.

South Bay 69 kV Sub-area

This sub-area has been eliminated because South Bay Units 3 and 4 are retired.

San Diego overall:

The most limiting contingency in the San Diego area is described by the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This contingency establishes a LCR of 3146 MW in 2011 (includes 188 MW of QF generation and 6 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went down by 91 MW and that lead to a decrease in the LCR by same amount. Also the new Otay Mesa Power Plant's NQC was increased from 573 MW to 603 MW, increasing the LCR by 30 MW. In addition, losses increased by 7 MW post SWPL out contingency, causing LCR to increase by the same amount.

San Diego Overall Requirements:

2011	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	188	6	3227	3421

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) ²⁷	3146	0	3146
Category C (Multiple) ²⁸	3146	61	3207

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

²⁸ Multiple contingencies means that the system will be able to 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.