California ISO
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California Independent
System Operator

2008
LOCAL CAPACITY TECHNICAL ANALYSIS

REPORT
AND STUDY RESULTS

~~March~~ Updated April ~~9~~3, 2007

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

This Report documents the results and recommendations of the 2008 Local Capacity Requirements (LCR) Study. The LCR ~~s~~Study assumptions, processes, and criteria ~~for this study~~ were discussed and recommended through the LCR Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing the 2008 LCR Study (see December 6, 2006 LSAG meeting notes at http://www.caiso.com/1b64/1b648dea14820.pdf). On balance, the assumptions, processes, and criteria used for the 2008 LCR Study mirror those used in the 2007 LCR Study which were adopted by CPUC in the 2007 Resource Adequacy Requirements program.

These 2008 LCR study results are provided to the CPUC for consideration in its 2008 resource adequacy requirements program. These results will also be used by the CAISO for establishing the scope of local capacity needs and for allocating appropriate costs of any necessary CAISO procurement of local capacity following implementation of its Market Redesign and Technology Upgrade ("MRTU") project in accordance with the CAISO's FERC-approved MRTU Tariff.[2] In this regard, the 2008 LCR Study also provides additional information like sub-area needs and effectiveness factors (where applicable) in order to allow LSEs to engage in more informed procurement.

Overall, the LCR need trended upward due to load growth. The ~~two~~ three exceptions are (1) the Greater Bay Area, where the LCR was reduced due to the

[1] The Local capacity requirements Study Advisory Group (LSAG) is formed from a representative cross-section of stakeholders, technically qualified to assess the issues related to the study assumptions, process and criteria of the existing LCR methodology and to recommend changes, where needed that could be implemented into the 2008 LCR study.

[2] The CAISO, under Section 40.3 of the CAISO MRTU Tariff, has the authority to procure generation capacity to backstop LSE procurement for two basic reasons: 1) an LSE did not procure sufficient resources to meet its individual local area resource obligation and that failure results in a collective deficiency of capacity that prevents compliance with Applicable Reliability Criteria or 2) LSEs collectively satisfied their local area resource obligations, but their procurement in aggregate did not permit the CAISO to meet Applicable Reliability Criteria.

installation of the new Vaca-Dixon 500/230 kV transformer, ~~and~~ (2) the LA Basin, where the LCR increased, and (3) creation of a Big Creek/Ventura local area.

➢ **Increase in LA Basin**

The increase in LA Basin LCR arises from the fact that the 2007 LCR Study did not have the benefit of results from a then-pending SCE study evaluating the effect on the South of Lugo operational path rating of transmission upgrades that were still under construction at the time of the 2007 LCR Study. The 2008 LCR study incorporates the outcome of the SCE study and therefore reflects the current, accurate South of Lugo operational path rating. Thus, the increase in capacity needs in the LA Basin is based on differences between the manner in which the CAISO attempt to account for the unavailability and uncertainty of the study results in the 2007 LCR Study and the use of actual final results of the SCE study in the 2008 LCR Study.

At the time the 2007 LCR Study was performed, South of Lugo had a formal operational path rating of 5600 MW. However, the CAISO understood that the South of Lugo operational path rating would increase during the following year when CAISO-approved transmission upgrades were completed or finally implemented by SCE. The extent of the increase was unknown because the new South of Lugo operational path rating was under development by SCE. The new formal South of Lugo operational path rating is 6100 MW as a result of the completed upgrades.

Accordingly, at the time the 2007 LCR study was performed, the CAISO identified two potential means of addressing the uncertainty surrounding the South of Lugo operational path rating. The first option was to use the approved South of Lugo operational rating of 5600 MW. This option would have resulted in a 2007 LCR need driven by the loss of Devers-Valley 500 kV line with SONGS #3 unit out of service, while maintaining the 5600 MW South of Lugo operational path rating. Such an outcome would have been equal to last year's projected need plus the SONGS #3 units output and additional generation to keep the path bellow the 5600 MW limit (see footnote 24 in page 65 under the 2007 LCR Report) (e.g., 8843 + 1080 + 900 = 10823 MW). The second option ignored the existing 5600 MW operational path rating as obsolete and, instead, utilized the next worst contingency in the area based on the same criteria published in page 15 of the 2007 LCR report.

The CAISO selected the second option, which resulted in a 2007 LA Basin LCR need of 8843 MW. It decided that the first option was unfair to LSEs and ratepayers not to take advantage of the upgrades simply because SCE had not yet completed its study of, and the CAISO could not validate, the new operating rating for the South of Lugo path. Thus, had the accurate data been used, the real need for 2007 should have been equal with last year's projected need plus the SONGS #3 units output (e.g., 8843 + 1080 = 9923 MW). It should be noted that the South of Lugo upgrades lowered the LCR needs by 900 MW (e.g., 10823 – 9923 = 900 MW). Finally, after SCE completed, and the CAISO approved, the new 6100 MW South of Lugo operational path rating, the CAISO reassessed LSE procurement in the LA Basin and confirmed that the combined LSE procurement exceeded the actual 9923 MW requirement for 2007.

Thus, from 2007 to 2008, there was no change in study methodology or inconsistent application of study protocols across the CAISO controlled system. In retrospect, the CAISO could have assumed or estimated an operational path rating on South of Lugo or any path for which studies are incomplete. This approach can be taken in the future if stakeholders agree that it represents a better alternative.

- **Big Creek/Ventura Local Area**

Additionally, there is a new local area in southern California designated as the Big Creek/Ventura area which has been previously described in the SCE Transmission Plan as well as in the CAISO's 2009-2011 Long-Term LCR technical analysis study (http://www.caiso.com/18d8/18d8ce1118390.pdf) and in the CAISO's 2007 Transmission Plan (http://www.caiso.com/1b6b/1b6bb4d51db0.pdf).

Below is a comparison of the 2007 vs. 2008 total LCR need:

2007 Local Capacity Needs

	Qualifying Capacity			2007 LCR Need Based on Category B			2007 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**
North Coast / North Bay	158	861	1019	582	0	**582**	582	0	**582**
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**
Stockton	314	257	571	432	0	**432**	536	53	**589**
Greater Bay	1314	5231	6545	4771	0	**4771**	4771	0	**4771**
Greater Fresno	575	2337	2912	2115	0	**2115**	2151	68	**2219**
Kern	978	31	1009	554	0	**554**	769	17	**786**
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**
Big Creek/ Ventura	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	**N/A**
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**
Total	**8185**	**19379**	**27564**	**22113**	**205**	**22318**	**22468**	**466**	**22934**

2008 Local Capacity Needs

	Qualifying Capacity			2008 LCR Need Based on Category B			2008 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**
Humboldt	45	135	180	175	0	**175**	175	0	**175**
North Coast / North Bay	262	621	883	676	0	**676**	676	0	**676**
Sierra	1014	766	1780	1780	89	**1869**	1780	312	**2092**
Stockton	272	264	536	460	15	**475**	536	250	**786**
Greater Bay	1116	5098	6214	4688	0	**4688**	4688	0	**4688**
Greater Fresno	496	2495	2991	2212	0	**2212**	2274	108	**2382**
Kern	615	31	646	259	0	**259**	463	23	**486**
LA Basin	3545	8545	12093	10~~50~~130*	0	**10~~50~~130***	10~~50~~130*	0	**10~~50~~130***
Big Creek/ Ventura	1463	3933	5396	3562	0	**3562**	3658	0	**3658**
San Diego	201	2758	2959	2957	0	**2957**	2957	0	**2957**

Total	**9029**	**24646**	**33678**	~~27269~~26899	**104**	~~27373~~27003	~~27707~~27337	**693**	~~28400~~28030

~~* - Potentially higher requirements combined with another area (see detail description).~~

Regarding the 2007 data the term “Qualifying Capacity” used in this report represents the “Gross Qualifying Capacity” (as of 1/12/2006) and it may be slightly higher, for certain generators, then the “Net Qualifying Capacity” as presented in the official list posted on the CAISO web site at:

http://www.caiso.com/1796/179694f65b9f0.xls

The difference between the terms “Qualifying Capacity” and “Net Qualifying Capacity” is that certain generators have associated plant load (pumps, lighting, controls, etc.) and thus, the “Net Qualifying Capacity” represents the output from the generator after the plant load has been netted out. This LCR study, however, incorporates the plant load into the “total load” calculation from these generators.

Regarding the 2008 data the term “Qualifying Capacity” used in this report is the same as the latest “Net Qualifying Capacity” list posted on the CAISO web site at:

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

Along with this report a Local Area Resource list is provided with all units that qualify to meet the 2008 LCR needs.

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, “2008 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, “2008 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.

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II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the 2006 and the 2007 LCR technical analysis studies, the intent of the 2008 LCR Study is to identify specific areas within the CAISO Controlled Grid that have limited import capability into those areas and determine the 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 2008 LCR study the same criteria, input assumptions and methodology that were incorporated into its 2007 LCR Study. Several new methodologies were briefly discussed in the LSAG. The group concluded that there was no time to introduce a new methodology change in time to complete the 2008 studies. The discussion of new methodologies is continuing in LSAG. The original 2007 LCR study criteria, input assumptions and methodology were majority agreed to by interested parties at the CPUC directed meet and confer session held at the CAISO on February 17, 2006. These same input assumptions and methodology align with the criteria that was subsequently discussed and agreed to by the LCR Study Advisory Group ("LSAG") (see December 6, 2006 LSAG meeting notes found at http://www.caiso.com/1b64/1b648dea14820.pdf).

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous 2007 LCR Study as well as this 2008 LCR Study:

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

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

Further details regarding the 2008 LCR Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one control area does can affect the reliability of other control 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. For instance, certain categories require that the grid operator not only ensure grid integrity is maintained under certain adverse system conditions, e.g., security, but also that all customers continue to receive electric supply

[3] Pub. Utilities Code § 345

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

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

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

Upon the completion of the 2006 and 2007 LCR studies, the CAISO came under considerable scrutiny on how the N-1, N-1-1, and N-2 criteria were applied in these studies. Some argued that the CAISO had not applied these criteria correctly, and as a result, erroneous results had been presented. The CAISO has always, as it did then and as it does now, argued that its application of these criteria were correct, and as such, the results presented in the 2006 and 2007 LCR reports correctly represented the LCR need in the identified load pockets.

However, as a result of recommendations from stakeholders, the CAISO formed the LCR Study Advisory Group to assist the CAISO in its preparation for performing the 2008 LCR Study. The LSAG was formed in late 2006 and immediately undertook a review of several key LCR issues, where the clarification of the N-1, N-1-1, and N-2 criteria was considered. While LSAG is still completing the documentation of its work, of significant importance to the CAISO is the unanimous agreement among LSAG members that its application of the N-1, N-1-1, and N-2 criteria in the 2007 LCR study was done correctly. Given this conclusion, the application of these criteria in the 2008 LCR Study will be consistent with the 2007 LCR Study. The criteria used in both the 2007 and 2008 studies conform in nearly all respects to NERC reliability standards that will become mandatory by July 1, 2007 with penalty sanctions as approved by FERC. LSAG members and stakeholders noted that the terminology N-1-1 is not included in NERC reliability standards and can create confusion. 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.

LSAG discussion on these criteria clearly illustrated that a detailed discussion/explanation of these criteria and how they should be applied in all “going forward” LCR Studies was needed. LSAG is currently preparing this discussion/explanation in the documentation of their work. Once completed, this documentation will be distributed to the Stakeholders.

E. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCR Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads however the CAISO will also test 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 and criteria.

b. <u>Performance Criteria- Category C</u>

The NERC 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 (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

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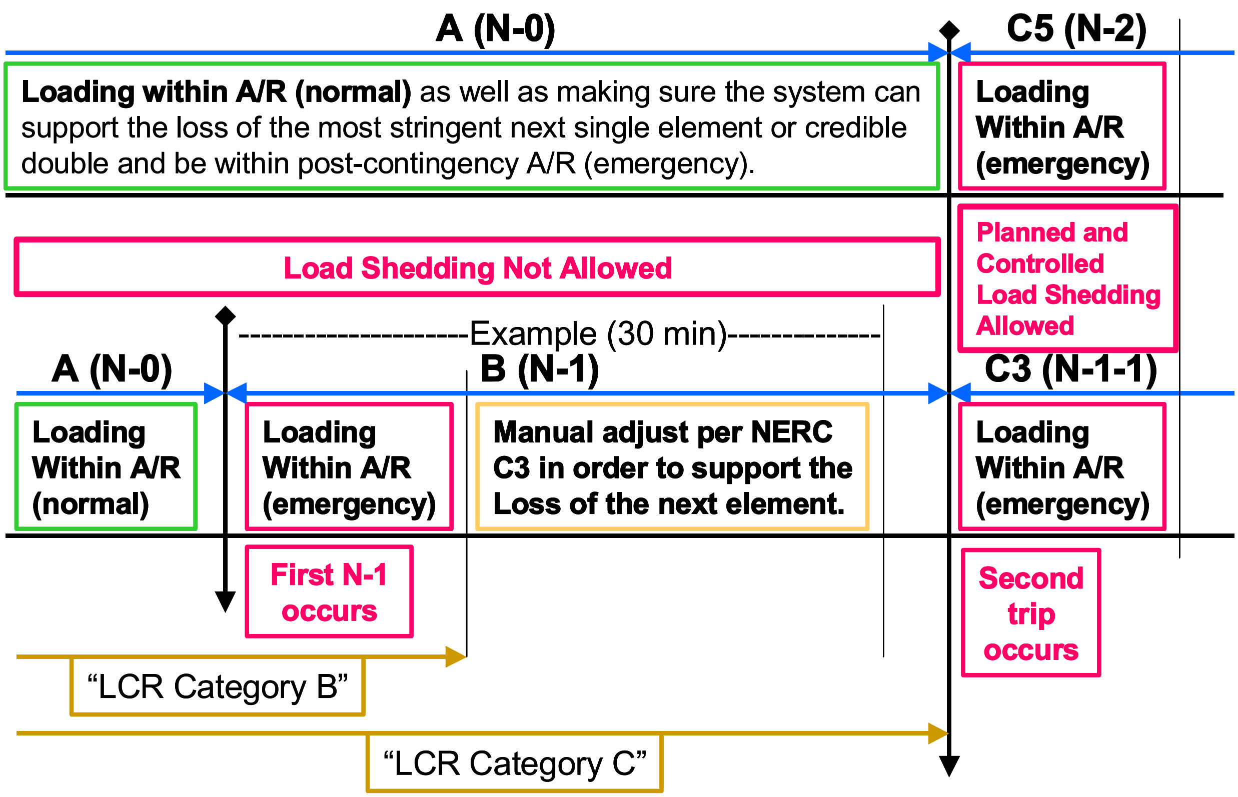
[4] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit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

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 Applicable 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).**



Definition of Terms

Applicable Rating:

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

Normal rating is to be used under normal conditions.

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

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

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

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

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

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

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

System Readjustment:

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

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

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

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

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

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

A robust California transmission system should be 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 should be used first (and included in the LCR requirement) before resorting to involuntary load curtailment. The footnote can be used as a last resort for criteria compliance issues only if there are no resources available in the area.

This interpretation tends to guarantee that dropping of load is done only as a last resort for Category B conditions, if no other resource measures are available and it is in line with existing operating practices. Doing otherwise could institutionalize the dropping of load as the preferred way of planning the transmission system under Category B conditions and, as a consequence, it may seriously increase the exposure to outages by changing the manner in which the system is operated.

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 the CAISO Grid Planning criteria.

This is a somewhat controversial aspect of the interpretation of existing criteria. This item is very specific in the CAISO grid planning criteria. 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 needs to be dispatched in the field to do switching and 30 minutes does not allow sufficient time. If approved, an exemption from the existing time requirements may be given for small local areas with very limited exposure and impact, clearly described in operating procedures, and only until remote controlled switching equipment can be installed.

Planned load drop:

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

Controlled load drop:

Is achieved with the use of a Special Protection Scheme.

Special Protection Scheme:

All known SPS shall all be used. New SPS needs to be verified and approved by the CAISO and needs to comply with the new SPS guideline described in the CAISO Grid Planning Standards.

F. The Two Options Presented In This LCR Study

This LCR study sets forth different solution "options" with varying ranges of potential service reliability consistent with CAISO's Applicable Reliability Criteria:

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 Applicable Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Applicable 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 including load interruptions prior to the actual occurrence of the second contingency.[5]

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

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.

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 (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 will be interrupted in the event the second contingency occurs.

This Option 2 is the local capacity level that the CAISO needs in order to reliably operate the grid per NERC, WECC and CAISO standards. As such the CAISO is proposing that the CPUC adopt it through its RA proceedings.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

Table 4: Criteria Comparison

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

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

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

1. Power Flow Assessment:

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

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

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

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

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

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

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

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1

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

2. Post Transient Load Flow Assessment:

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

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

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

3. Stability Assessment:

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

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

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

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

a. PTO Loads in Base Case

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

i. Determination of division loads

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

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed would need to be allocated to those buses. The allocation process is different depending on the load types. For the most part each PTO's 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 would be allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads usually is higher then the load forecast because some load like self-generation and generation-plant are load behind the meter and they need to be modeled in the base cases, however for the most part metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCR analysis

The LCR technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 15.2. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

To complete the local area component of this study, 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 area as provided to the ISO by the Participating Transmission Owners ("PTOs").

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR needs. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Locational Capacity Requirement Study Results

A. Summary of Study Results

The LCR results reflect 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 and nuclear units). The second set is "market" generation. Within this overview, 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: 2007 Local Capacity Needs vs. Peak Load and Local Area Generation

	2007 Total LCR (MW)	**Peak Load (1 in10) (MW)**	**2007 LCR as % of Peak Load**	**Total Dependable Local Area Generation (MW)**	**2007 LCR as % of Total Area Generation**
Humboldt	202	197	103%	206	98%
North Coast/North Bay	582	1,513	38%	1,019	57%
Sierra	2,161	1,841	117%	1,848	117%**
Stockton	589	1,267	46%	571	103%**
Greater Bay	4,771	9,633	50%	6,545	73%
Greater Fresno	2,219	3,154	70%	2,912	76%**
Kern	786	1,209	65%	1,009	78%**
LA Basin	8,843	19,325	46%	10,522	84%
Big Creek/Ventura	N/A	N/A	N/A	N/A	N/A
San Diego	2,781	4,742	59%	2,932	95%
Total	**22,934**	**42,881***	**53%***	**27,471**	**83%**

Table 6: 2008 Local Capacity Needs vs. Peak Load and Local Area Generation

	2008 Total LCR (MW)	Peak Load (1 in10) (MW)	2008 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2008 LCR as % of Total Area Generation
Humboldt	175	199	88%	180	97%
North Coast/North Bay	676	1495	45%	883	77%
Sierra	2092	2091	100%	1780	118%**
Stockton	786	1333	59%	536	147%**
Greater Bay	4688	9870	47%	6214	75%
Greater Fresno	2382	3260	73%	2991	80%**
Kern	486	1324	37%	646	75%**
LA Basin	~~10500~~10130	19648	~~53~~52%	12093	~~87~~84%
Big Creek/Ventura	3658	4911	74%	5396	68%
San Diego	2957	4916	60%	2959	100%
Total	**28,~~400~~030**	**49,047***	**~~58~~57%***	**33,678**	**~~84~~83%**

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

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

Tables 5 and 6 shows how much of the local area load is dependent on local generation and how much local generation needs to be available in order to reliably (see LCR criteria) serve the load in those Local Capacity Areas. 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.

B. Summary of Zonal Needs

The CAISO, PG&E, SDG&E, SCE and TURN ~~is~~ are proposing an alternative method for determining zonal needs that is currently under discussion at the CPUC as part of the RA Phase 2, Track 1 issues. Based on the existing import allocation methodology, the only major 500 kV constraint not accounted for is path 26 (Midway-Vincent). ***The recently proposed method under review could allocate capacity on path 26 similar to the way imports are proposed to be allocated to LSEs.*** Thus as a consequence from a high level, and without further refinement at this juncture, the total ~~minimum~~ resources needeeds~~s~~ (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)	(-)~~Maximum~~ Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	28,778	4,318	-8,598	-~~3,750~~3,430	**~~20,758~~21,078**
NP26=NP15+ZP26	26,220	3,933	-4,101	-~~3,250~~2,583	**~~22,802~~23,469**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2008.

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

Allocated Imports are the actual 2007 numbers that are not expected to change much by 2008 because there are no additional transmission additions to the grid between now and summer of 2008.

Allocated ~~Maximum~~ 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 control area[6] and (2) loop flow[7] from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North). ~~represents the path rating (N to S for SP 26 transfers and S to N for NP 26 transfers) adjusted for the inherent loop flow across WECC interconnected system (estimated here at 250 MW). An additional derate of P26 transfer capability may be necessary to accommodate legacy transmission contracts.~~

The SP 26 load forecast, import allocation and zonal results refer to the CAISO control area only. The NP 26 load forecast, import allocation and zonal results include the load associated with embedded control areas within the CAISO footprint. This is

[6] 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 control area. These particular ETCs represent physical transmission capacity that cannot be allocated to LSEs within the CAISO control area.

[7] "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.

done in order to be consistent with the import allocation methodology which also considers that same load embedded in other control areas within the CAISO footprint.

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.

C. Summary of Results by Local Area

Each local 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 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

<u>Area Definition</u>

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 2008 busload within the defined area: 194 MW with 5 MW of losses resulting in total load + losses of 199 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	NQC Comments	CAISO Tag
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	12.58	1		QF/Selfgen
HUMBPP_1_MOBLE2	31154	HUMBOLDT	13.2	15.00	2		Market

HUMBPP_1_MOBLE3	31154	HUMBOLDT	13.2	15.00	1		Market
HUMBPP_7_UNIT 1	31170	HMBOLDT1	13.8	52.00	1		Market
HUMBPP_7_UNIT 2	31172	HMBOLDT2	13.8	53.00	1		Market
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1		QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	12.00	1	No NQC - historical data	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	10.33	1		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	10.33	2		QF/Selfgen
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	No NQC - historical data	Market

Critical Contingency Analysis Summary

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV line over-lapping with an outage of one Humboldt Bay Power Plant. The local area limitation is low voltage and reactive power margin. This contingency establishes a Local Capacity ~~Requirement~~ Need of 175 MW in 2008 (includes 45 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Humboldt Overall Requirements:

2008	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	45	0	135	180

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[8]	175	0	175
Category C (Multiple)[9]	175	0	175

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

2. 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 2008 busload within the defined area: 1437 MW with 58 MW of losses resulting in total load + losses of 1495 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_UNIT 1	31435	GEO.ENGY	9.1	6.80	1	Eagle Rock, Eagle Rock-Fulton, Lakeville		QF/Selfgen
ADLIN_1_UNIT 2	31435	GEO.ENGY	9.1	7.01	2	Eagle Rock, Eagle Rock-Fulton, Lakeville		QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	60.00	1	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	36.00	1	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	36.00	2	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market

GYS7X8_7_UNITS	31408	GEYSER78	13.8	31.00	1	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	31.00	2	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market
INDVLY_1_UNITS	31436	INDIAN V	9.1	1.79	1	Eagle Rock, Eagle Rock-Fulton, Lakeville		QF/Selfgen
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Eagle Rock-Fulton, Lakeville		Market
BEARCN_2_UNIT 1	31402	BEAR CAN	13.8	7.41	1	Fulton, Eagle Rock-Fulton, Lakeville		QF/Selfgen
BEARCN_2_UNIT 2	31402	BEAR CAN	13.8	7.37	2	Fulton, Eagle Rock-Fulton, Lakeville		QF/Selfgen
GEYS12_7_UNIT12	31414	GEYSER12	13.8	41.00	1	Fulton, Eagle Rock-Fulton, Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	63.00	1	Fulton, Eagle Rock-Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	75.00	1	Fulton, Eagle Rock-Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	51.00	1	Fulton, Eagle Rock-Fulton, Lakeville		Market
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.50	1	Fulton, Eagle Rock-Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.50	2	Fulton, Eagle Rock-Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.59	3	Fulton, Eagle Rock-Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	31.00	1	Fulton, Eagle Rock-Fulton, Lakeville		MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	30.00	1	Fulton, Eagle Rock-Fulton, Lakeville		MUNI
SNMALF_6_UNITS	31446	SONMA LF	9.1	7.70	1	Fulton, Eagle Rock-Fulton, Lakeville		QF/Selfgen
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.07	1	Fulton, Eagle Rock-Fulton, Lakeville		QF/Selfgen
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.07	2	Fulton, Eagle Rock-Fulton, Lakeville		QF/Selfgen
	31421	BOTTLERK	13.8	0.00	1	Fulton, Eagle Rock-Fulton, Lakeville	No NQC - historical data	Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	70.00	1	Lakeville		Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	40.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	34.25	1	Lakeville		MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	32.25	1	Lakeville		MUNI
SANTFG_7_UNITS	31400	SANTA FE	13.8	33.21	1	Lakeville		QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	33.20	2	Lakeville		QF/Selfgen
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	38.00	1	Lakeville		Market

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 Local Capacity ~~Requirement~~ Need of 215 MW in 2008 (includes 16 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Sonoma-Pueblo 115 kV line #1. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 366 MW (includes 68 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the units required to meet the Eagle Rock pocket count towards the Fulton total requirement.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
38112	NCPA2GY2	1	25
38110	NCPA2GY1	1	25
31422	GEYSER17	1	25
31421	BOTTLERK	1	25
31420	GEYSER16	1	25
31418	GEYSER14	1	25

31414	GEYSER12	1	25
31404	WEST FOR	2	25
31404	WEST FOR	1	25
31402	BEAR CAN	1	25
31402	BEAR CAN	2	25
31435	GEO.ENGY	1	15
31435	GEO.ENGY	2	15
31412	GEYSER11	1	15
31408	GEYSER78	1	15
31408	GEYSER78	2	15
31406	GEYSR5-6	1	15
31406	GEYSR5-6	2	15

Lakeville Sub-area

The 2008 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 Local Capacity ~~Requirement~~ Need of 676 MW (includes 134 MW of QF generation). The LCR requirement for Eagle Rock and Fulton sub-area can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	37
31430	SMUDGEO1	1	37
31400	SANTA FE	1	37
31416	GEYSER13	1	37
31424	GEYSER18	1	37
31426	GEYSER20	1	37
38106	NCPA1GY1	1	37
38108	NCPA1GY2	1	37
31421	BOTTLERK	1	35
31404	WEST FOR	2	35
31402	BEAR CAN	1	35
31402	BEAR CAN	2	35
31404	WEST FOR	1	35
31414	GEYSER12	1	35
31418	GEYSER14	1	35
31420	GEYSER16	1	35

31422	GEYSER17	1	35
38110	NCPA2GY1	1	35
38112	NCPA2GY2	1	35
31406	GEYSR5-6	1	19
31406	GEYSR5-6	2	19
31408	GEYSER78	1	19
31408	GEYSER78	2	19
31412	GEYSER11	1	19
31435	GEO.ENGY	1	19
31435	GEO.ENGY	2	19

North Coast/North Bay Overall Requirements:

2008	QF/Seflgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	134	128	621	883

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[10]	676	0	676
Category C (Multiple)[11]	676	0	676

3. Sierra Area

<u>Area Definition</u>

The transmission tie lines into the Sierra Area are:

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

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

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) Gold Hill is in Lodi Stig is out
12) Gold Hill is in Lake is out

Total 2008 busload within the defined area: 1983 MW with 108 MW of losses resulting in total load + losses of 2091 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
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	7.54	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	38.52	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	6.50	1	South of Table Mountain	No NQC - historical data	MUNI
NAROW2_2_UNIT	32468	NARROWS2	9.1	34.88	1	South of Table Mountain	Monthly NQC - used August for LCR	MUNI
BIOMAS_1_UNIT 1	32156	WOODLAND	9.1	18.53	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
BOWMN_6_UNIT	32480	BOWMAN	9.1	1.15	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	5.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market

DRUM_7_PL3X4	32506	DRUM 3-4	6.6	14.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	14.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.68	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.68	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
NA	32162	RIV.DLTA	9.11	3.10	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	5.80	3	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.78	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.78	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
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/Self gen
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	39.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
NA	31862	DEADWOOD	9.1	2.00	1	Drum-Rio Oso, South of Table Mountain	No NQC - historical data	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	13.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
GRNLF1_1_UNIT 1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	45.79	1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Self gen
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	49.50	1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Self gen
HALSEY_6_UNIT	32478	HALSEY F	9.1	11.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
WISE_1_UNIT 1	32512	WISE	12	9.20	1	Placer, Drum-Rio Oso,	Monthly NQC -	Market

						South of Rio Oso, South of Palermo, South of Table Mountain	used August for LCR	
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
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	1.30	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	7.00	1	Placerville, South of Rio Oso, South of Table Mountain		Market
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain		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
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
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
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
HELLHL_6_UNIT	32486	HELLHOLE	9.1	0.50	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - historical data	MUNI
MIDFRK_7_UNIT 1	32456	MIDLFORK	13.8	63.40	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - historical data	MUNI
MIDFRK_7_UNIT 2	32456	MIDLFORK	13.8	63.40	2	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - historical data	MUNI
RALSTN_7_UNIT 1	32458	RALSTON	13.8	86.00	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - historical data	MUNI
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	4.19	1	Drum-Rio Oso, South of Palermo, South of Rio Oso, South of Table		QF/Self gen

						Mountain		
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	19.64	1	Drum-Rio Oso, South of Palermo, South of Rio Oso, South of Table Mountain		QF/Self gen
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	165.80	1	South of Table Mountain		MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Monthly NQC - used August for LCR	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	0.01	1	South of Table Mountain	Monthly NQC - used August for LCR	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	6.08	1	Drum-Rio Oso, South of Table Mountain		QF/Self gen
PACORO_6_UNIT	31890	PO POWER	9.1	8.20	1	Drum-Rio Oso, South of Table Mountain		QF/Self gen
PACORO_6_UNIT	31890	PO POWER	9.1	8.20	2	Drum-Rio Oso, South of Table Mountain		QF/Self gen

<u>Critical Contingency Analysis Summary</u>

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV line with one of the Colgate Units out of service. The area limitation is thermal overloading of the Table Mt-Palermo 230 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ <u>Need</u> of 1780 MW (includes 214 MW of QF and 800 MW of Muni generation) in 2008 as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

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

<u>No sub-area analysis is required. It is done here for planning purposes only.</u>

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV upgrade project.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Yuba City Cogen unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 145 MW (includes 96 MW of QF generation and 3 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this pocket. It is assumed that Oliverhurst is normally served from Palermo-Bogue 115 kV line and not from Pease-Rio Oso 115 kV line.

Effectiveness factors:

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

Bogue Sub-area

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

South of Palermo Sub-area

The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 1275 MW (includes 475 MW of QF and Muni generation as well as 75 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this pocket. It is assumed that Oliverhurst is normally served from Palermo-Bogue 115 kV line and not from Pease-Rio Oso 115 kV line.

The single most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 1140 MW (includes 475 MW of QF and Muni generation) in 2008.

It is assumed that Oliverhurst is normally served from Palermo-Bogue 115 kV line and not from Pease-Rio Oso 115 kV line.

Effectiveness factors:

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

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 95 MW (includes 0 MW of QF and Muni generation as well as 66 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line with one of the El Dorado units out of service. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 21 MW (includes 0 MW of QF and Muni generation) in 2008.

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 Local Capacity ~~Requirement~~ Need of 148 MW (includes 0 MW of QF and Muni generation as well as 124 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Drum-Higgins 115 kV line with the Halsey unit out of service. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 51 MW (includes 0 MW of QF and Muni generation as well as 27 MW of deficiency) in 2008.

Effectiveness factors:

All units within this area (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 a Local Capacity ~~Requirement~~ Need of 831 MW (includes 411 MW of QF and Muni generation as well as 177 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this pocket.

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 a Local Capacity ~~Requirement~~ Need of 651 MW in 2008 (includes 411 MW of QF and Muni generation).

Effectiveness factors:

All units within this area are needed for the most limiting contingency 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 Gold Hill-Ralston 230 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 584 MW (includes 310 MW of QF and Muni generation as well as 197 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 441 MW (includes 310 MW of QF and Muni generation as well as 72 MW of deficiency) in 2008.

Effectiveness factors:

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

Sierra Overall Requirements:

2008	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	214	800	766	1780

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[12]	1780	89	1869
Category C (Multiple)[13]	1780	312	2092

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

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

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

5) Tesla-Salado-Manteca 115 kV line
6) Tesla-Shulte 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 Shulte is in
7) Tesla is out Kasson and Manteca are in

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

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

The substations that delineate the Lockeford Sub-area are:

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

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

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

The substations that delineate the Stagg Sub-area is:

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

Total 2008 busload within the defined area: 1306 MW with 27 MW of losses resulting in total load + losses of 1333 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
LODI25_2_UNIT 1	38120	LODI25CT	9.11	25.00	1	Lockeford	No NQC - historical data	MUNI

NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - historical data	QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	Stagg		MUNI
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	TeslaBellota	Monthly NQC - used August for LCR	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	1	TeslaBellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	2	TeslaBellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	3	TeslaBellota	No NQC - historical data	MUNI
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	TeslaBellota	Monthly NQC - used August for LCR	MUNI
SCHLTE_1_UNITA1	33805	GWFTRCY1	13.8	83.56	1	TeslaBellota		Market
SCHLTE_1_UNITA2	33807	GWFTRCY2	13.8	82.88	1	TeslaBellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	8.54	1	TeslaBellota		MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	3.20	1	TeslaBellota	No NQC - historical data	QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	6.70	1	TeslaBellota		Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	TeslaBellota		Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	16.33	1	TeslaBellota		QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	45.33	1	TeslaBellota		QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	TeslaBellota	Monthly NQC - used August for LCR	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	TeslaBellota	Monthly NQC - used August for LCR	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	14.62	1	TeslaBellota		QF/Selfgen

Critical Contingency Analysis Summary

Stockton overall

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

Tesla-Bellota Sub-area

The 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 overloading of the Manteca-Ingram Creek section of Tesla-Salado-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 565 MW (includes 195 MW of QF and Muni generation as well as 105 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Kasson-Manteca 115 kV line and the loss of the Stanislaus unit #1. The area limitation is thermal overloading of the Manteca-Ingram Creek section of Tesla-Salado-Manteca 115 kV line above its emergency rating. This single contingency establishes a Local

Capacity ~~Requirement~~ Need of 475 MW (includes 195 MW of QF and Muni generation as well as 15 MW of deficiency) in 2008.

Effectiveness factors:

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

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 72 MW (including 28 MW of QF and Muni as well as a deficiency of 45 MW) in 2008 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

The outage of the Tesla-Stagg 230 kV line and Tesla-Eight Mile 230 kV line causes low voltages at Stagg, Eight Mile Road and Lodi Stig 230 kV busses. Post-contingency steady-state voltages at these three busses are less than 0.90 pu. Lodi Stig generating unit is needed to support voltage at these three 230 kV busses. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 150 MW (includes 50 MW of Muni generation as well as 100 MW of deficiency) in 2008 as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Stockton Overall Requirements:

2008	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	82	190	264	536

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[14]	460	15	475
Category C (Multiple)[15]	536	250	786

5. Greater Bay Area

Area Definition

The transmission tie lines into the Greater Bay Area are:

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

The substations that delineate the Greater Bay Area are:

1) Lakeville is out Sobrante is in
2) Ignacio is out Sobrante is in

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

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

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

Total 2008 busload within the defined area: 9601 MW with 268 MW of losses resulting in total load + losses of 9870 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
GILROY_1_UNIT	35850	GLRY COG	13.8	66.00	1	Llagas		Market
GILROY_1_UNIT	35850	GLRY COG	13.8	34.00	2	Llagas		Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.00	1	Llagas		Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.00	1	Llagas		Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	45.00	1	Llagas		Market
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	78.64	1	None	Monthly NQC - used August for LCR	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	16.41	1	None	Monthly NQC - used August for LCR	Wind
CARDCG_1_UNITS	33463	CARDINAL	12.47	26.91	1	None		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.47	26.91	2	None		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
FLOWD2_2_UNIT 1	35318	FLOWDPTR	9.11	5.52	1	None	Monthly NQC - used August for LCR	Wind
GAYCRZ_1_UNIT 1	33145	CROWN.Z.	13.8	40.00	1	None	No NQC - historical data	QF/Selfgen
GAYCRZ_1_UNIT 1	33145	CROWN.Z.	13.8	5.40	2	None	No NQC - historical data	QF/Selfgen
GRZZLY_1_BERKLY	32740	HILLSIDE	115	26.73	1	None		QF/Selfgen
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	4.93	1	None	Monthly NQC - used August for LCR	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	None		Market

LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	None		Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	None		Market
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	None		Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	1.83	1	None	Monthly NQC - used August for LCR	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	1.07	1	None		QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.06	1	None		QF/Selfgen
USWND1_2_UNITS	33838	USWP_#3	9.11	9.52	1	None	Monthly NQC - used August for LCR	Wind
USWNDR_2_SMUD	32169	SOLANOWP	21	12.40	1	None	No NQC - historical data	Wind
USWNDR_2_UNITS	32168	USWINDPW	9.11	13.13	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.92	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.93	2	None	Monthly NQC - used August for LCR	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	2.10	1	None	Monthly NQC - used August for LCR	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	3.75	1	None	Monthly NQC - used August for LCR	Wind
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.00	1	Oakland		MUNI
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
CROKET_7_UNIT	32900	CRCKTCOG	18	240.00	1	Pittsburg		QF/Selfgen
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg		Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg		Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg		Market
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg		Market
DOWCHM_1_UNITS	33161	DOWCHEM 1	13.8	10.30	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33162	DOWCHEM 2	13.8	13.63	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33163	DOWCHEM 3	13.8	13.63	1	Pittsburg		QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	19.00	1	Pittsburg		QF/Selfgen

GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.81	1	Pittsburg		QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	19.16	1	Pittsburg		QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	19.19	1	Pittsburg		QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	18.83	1	Pittsburg		QF/Selfgen
IMHOFF_1_UNIT 1	33136	CCCSD	12.47	4.40	1	Pittsburg	No NQC - historical data	QF/Selfgen
LMEC_1_PL1X3	33112	LMECCT1	18	164.37	1	Pittsburg		Market
LMEC_1_PL1X3	33111	LMECCT2	18	164.37	1	Pittsburg		Market
LMEC_1_PL1X3	33113	LMECST1	18	231.26	1	Pittsburg		Market
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
SHELRF_1_UNITS	33141	SHELL 1	12.47	20.00	1	Pittsburg	No NQC - historical data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.47	40.00	1	Pittsburg	No NQC - historical data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.47	40.00	1	Pittsburg	No NQC - historical data	QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.42	1	Pittsburg		QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.41	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	6.30	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	6.29	2	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	6.29	3	Pittsburg		QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	20.00	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.70	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.69	2	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.69	3	Pittsburg		QF/Selfgen
POTRPP_7_UNIT 3	33252	POTRERO3	20	206.00	1	San Francisco		Market
POTRPP_7_UNIT 4	33253	POTRERO4	13.8	52.00	1	San Francisco		Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	52.00	1	San Francisco		Market
POTRPP_7_UNIT 6	33255	POTRERO6	13.8	52.00	1	San Francisco		Market
UNTDQF_7_UNITS	33466	UNTED CO	9.11	26.93	1	San Francisco		QF/Selfgen
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	27.94	1	San Jose		QF/Selfgen
CONTAN_1_UNIT	36856	CSC_CCA	13.8	16.15	1	San Jose		QF/Selfgen

CSCCOG_1_UNIT 1	36854	CSC COG.	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	CSC COG.	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	CSC_GNR1	13.8	21.30	1	San Jose	Monthly NQC - used August for LCR	MUNI
CSCGNR_1_UNIT 2	36895	CSC_GNR2	13.8	21.30	2	San Jose	Monthly NQC - used August for LCR	MUNI
DUANE_1_PL1X3	36863	DVRPPCT1	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36864	DVRPPCT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRPPSTA	13.8	49.26	1	San Jose		MUNI
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - historical data	Market
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose		Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose		Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose		Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose		Market
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	185.68	1	San Jose		Market
METEC_2_PL1X3	35882	MEC CTG2	18	185.68	1	San Jose		Market
METEC_2_PL1X3	35883	MEC STG1	18	221.79	1	San Jose		Market
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	2.50	1	San Jose	No NQC - historical data	QF/Selfgen
ZANKER_1_UNIT 2	35861	SJ-SCL W	9.11	2.50	2	San Jose	No NQC - historical data	QF/Selfgen
NA	33469	P0527	4.16	1.90	1	None	No NQC - Pmax	Market
NA	33469	P0527	4.16	1.90	2	None	No NQC - Pmax	Market
NA	33469	P0527	4.16	1.90	3	None	No NQC - Pmax	Market
NA	33469	P0527	4.16	1.90	4	None	No NQC - Pmax	Market
NA	33469	P0527	4.16	1.90	5	None	No NQC - Pmax	Market
NA	33469	P0527	4.16	1.90	6	None	No NQC - Pmax	Market
NA	33469	P0527	4.16	1.90	7	None	No NQC - Pmax	Market

Critical Contingency Analysis Summary

San Francisco Sub-area

Per the CAISO Revised Action Plan for SF, Potrero units #3 and all three CTs (360 MW) will continue to be required until completion of the plan as it is presently described.

The most critical contingency is an outage of H-P #1 and H-P #3. The area limitation is thermal overloading of A-H-W #2 115kV Cable. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 360 MW (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area in 2008.

Effectiveness factors:

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

Oakland Sub-area

For 2008 the most critical contingency is an outage of the D-L 115 kV cable (with one of the Oakland CT's off-line). The area limitation is thermal overloading of the C-X #2 115 kV cable. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 105 MW in 2008 (includes 48 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area have the same effectiveness factor. 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 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 Local Capacity ~~Requirement~~ Need of 112 MW in 2008 (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

San Jose Sub-area

Due to existing SPS and future reconductoring this area has no requirements.

Pittsburg Sub-area

The most critical contingency is an outage of the Pittsburg-Tesla #1 or #2 230 kV line (with Delta Energy Center off-line). The sub-area area limitation is thermal overloading of the parallel Pittsburg-Tesla 230 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 2123 MW in 2008 (including 519 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this 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 (%)
33840	FLOWD3-6	1	86
33840	FLOWD3-6	2	86
33840	FLOWD3-6	3	86
33840	FLOWD3-6	4	86
33171	TRSVQ+NW	2	26
33171	TRSVQ+NW	1	26
33105	PTSB 5	1	26
33106	PTSB 6	1	26
30000	PTSB 7	1	26
33110	DEC CTG3	1	25
33109	DEC CTG2	1	25
33108	DEC CTG1	1	25
33107	DEC STG1	1	25
33113	LMECST1	1	24
33112	LMECCT1	1	24
33111	LMECCT2	1	24
33132	GWF #2	1	24
33161	DOWCHEM1	1	24
33162	DOWCHEM2	1	24
33163	DOWCHEM3	1	24
33151	FOSTER W	1	23
33151	FOSTER W	2	23
33151	FOSTER W	3	23
33141	SHELL 1	1	21
33143	SHELL 3	1	21
33142	SHELL 2	1	21
32900	CRCKTCOG	1	19
32910	UNOCAL	1	19

32910	UNOCAL	2	19
32910	UNOCAL	3	19
32920	UNION CH	1	19
32922	ChevGen2	1	18
32921	ChevGen1	1	18
32740	HILLSIDE	1	18
33135	GWF #5	1	18
38119	ALMDACT2	1	16
32903	OAKLND 3	1	16
32902	OAKLND 2	1	16
32901	OAKLND 1	1	16
38118	ALMDACT1	1	16
30464	EXXON_BH	1	9
33252	POTRERO3	1	7
33253	POTRERO4	1	7
33254	POTRERO5	1	7
33255	POTRERO6	1	7
33466	UNTED CO	1	7
35312	SEAWESTF	1	7
35316	ZOND SYS	1	7
35320	USW FRIC	1	7
32176	SHILOH	1	5
36865	DVRPPSTA	1	5
36864	DVRPPCT2	1	5
36863	DVRPPCT1	1	5
33178	RVEC_GEN	1	5
32175	CREEDGT1	3	5
32174	GOOSEHGT	2	5
32173	LAMBGT1	1	5
32172	HIGHWNDS	1	5
33134	GWF #4	1	5
33116	C.COS 6	1	5
33117	C.COS 7	1	5
33133	GWF #3	1	5
33145	CROWN.Z.	1	5
33145	CROWN.Z.	2	5
33131	GWF #1	1	5
36856	CSC_CCA	1	5
33463	CARDINAL	1	5
33463	CARDINAL	2	5
32168	USWINDPW	1	5
32168	USWINDPW	2	5
33838	USWP_#3	1	5

Bay Area overall

The most critical contingency is the loss of the Tesla-Metcalf 500 kV followed by Delta Energy Center or vice versa. The area limitation is reactive margin within the Bay Area as well as thermal overload of the Tesla #6 500/230 transformer. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 4688 MW in 2008 (includes 722 MW of QF, 150 MW of Wind and 244 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area. (The transformer bank requirement only includes units in the Greater Bay Area, assuming all effective units in Stockton are at their historical output levels and not included in the requirement total.)

Effectiveness factors:

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

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

Bay Area Overall Requirements:

2008	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	150	722	244	5098	6214

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[16]	4688	0	4688
Category C (Multiple)[17]	4688	0	4688

6. Greater Fresno Area

<u>Area Definition</u>

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Henrietta Tap 1 230 kV Line

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

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

2) Gates-Henrietta Tap 2 230 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-Gates #1 230 kV Line
7) Panoche-Gates #2 230 kV Line
8) Panoche-Coburn 230 kV Line
9) Panoche-Moss Landing 230 kV Line
10) Panoche-Los Banos #1 230 kV Line
11) Panoche-Los Banos #2 230 kV Line
12) Panoche-Dos Amigos 230 kV Line
13) Warnerville-Wilson 230 kV Line
14) Wilson-Melones 230 kV Line
15) Midway-Semitropic-Smyrna 115kV Line
16) 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 in Gates is out
7) Panoche is in Gates is out
8) Panoche is in Coburn is out
9) Panoche is in Moss Landing is out
10) Panoche is in Los Banos is out
11) Panoche is in Los Banos is out
12) Panoche is in Dos Amigos is out
13) Warnerville is out Wilson is in
14) Wilson is in Melones is out
15) Midway and Semitropic are out Smyrna is in
16) Coalinga is in San Miguel is out

2008 total busload within the defined area is 3149 MW with 111 MW of losses resulting in a total (load plus losses) of 3260 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
PINFLT_7_UNITS	38720	PINEFLAT	13.8	75.00	3	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	75.00	2	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	75.00	1	Wilson, Herndon		MUNI
GWFPWR_6_UNIT	34650	GWF-PWR.	9.11	23.87	1	Wilson, Henrietta		QF/Selfgen
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson, Henrietta		Market

HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson, Henrietta		Market
AGRICO_6_PL3N5	34608	AGRICO	13.8	21.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	42.62	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.38	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00	1	Wilson, Herndon		Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon		Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon		Market
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	19.70	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	9.76	1	Wilson		QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.25	2	Wilson		QF/Selfgen
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNEAGN	9.11	35.44	1	Wilson		QF/Selfgen
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	9.89	1	Wilson, Herndon		Market
FRIANT_6_UNITS	34636	FRIANTDM	6.6	8.49	2	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	4.53	3	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.20	4	Wilson		QF/Selfgen
GATES_6_UNIT	34553	WHD_GAT2	13.8	49.00	1	Wilson	No NQC - historical data	Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	84.40	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	84.40	1	Wilson, Herndon		Market
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
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	28.81	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	96.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	96.00	1	Wilson, Herndon		Market
MENBIO_6_UNIT	34334	BIO PWR	9.11	19.69	1	Wilson		QF/Selfgen
NA	34485	FRESNOWW	12.5	9.00	1	Wilson	No NQC - historical data	QF/Selfgen
ONLLPP_6_UNITS	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - historical data	MUNI

PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	42.78	1	Wilson		Market
PNOCHE_1_UNITB1	34142	WHD_PAN2	13.8	49.00	1	Wilson, Herndon	No NQC - historical data	Market
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	20.26	1	Wilson, Herndon		QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.60	1	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.60	2	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.60	3	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.60	4	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	0.00	5	Wilson		Market
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
INTTRB_6_UNIT	34342	INT.TURB	9.11	3.99	1	Wilson	Monthly NQC - used August for LCR	QF/Selfgen
SGREGY_6_SANGER	34646	SANGERCO	9.11	31.03	1	Wilson		QF/Selfgen
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Monthly NQC - used August for LCR	MUNI
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	6.31	1	Wilson, Merced		QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	5.04	1	Wilson	Monthly NQC - used August for LCR	MUNI
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.20	1	Wilson	Monthly NQC - used August for LCR	Market

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 Wanerville-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 followed by the loss of the Gates-Gregg 230 kV line, which could thermally overload the Warnerville - Wilson 230 kV line and the Gates-McCall 230 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 1563 MW (which includes 292 MW of Muni generation and 204 MW of QF generation) in 2008 as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical single 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 and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 1505 MW (which includes 292 MW of Muni generation and 204 MW of QF generation) in 2008.

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	43
34322	MERCEDFL	1	36
34320	MCSWAIN	1	36
34301	CHOWCOGN	1	35
34306	EXCHQUER	1	34
34658	WISHON	1	32
34658	WISHON	2	32
34658	WISHON	3	32
34658	WISHON	4	32
34631	SJ2GEN	1	32
34633	SJ2GEN	1	32
34636	FRIANTDM	2	31
34636	FRIANTDM	3	31
34636	FRIANTDM	4	31
34600	HELMS 1	1	31
34602	HELMS 2	1	31
34604	HELMS 3	1	31
34344	KERCKHOF	1	29
34344	KERCKHOF	2	29
34344	KERCKHOF	3	29
34308	KERCKHOF	1	29
34485	FRESNOWW	1	27
34648	DINUBA E	1	26
34616	KINGSRIV	1	25
34624	BALCH 1	1	25
34671	KRCDPCT1	1	24
34672	KRCDPCT2	1	24
34640	ULTR.PWR	1	23
34646	SANGERCO	1	23
34179	MADERA_G	1	23
34642	KINGSBUR	1	21

38720	PINE FLT	1	21
38720	PINE FLT	2	21
38720	PINE FLT	3	21
34610	HAAS	1	21
34610	HAAS	2	21
34612	BLCH 2-2	1	20
34614	BLCH 2-3	1	20
34433	GWF_HEP2	1	19
34431	GWF_HEP1	1	19
34334	BIO PWR	1	15
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	14
34186	DG_PAN1	1	12
34142	WHD_PAN2	1	12
34652	CHV.COAL	1	9
34652	CHV.COAL	2	9
34553	WHD_GAT2	1	9
34654	COLNGAGN	1	9
34342	INT.TURB	1	7
34316	ONEILPMP	1	6

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34610	HAAS	1	34
34610	HAAS	2	34
34612	BLCH 2-2	1	34
34614	BLCH 2-3	1	34
38720	PINE FLT	1	34
38720	PINE FLT	2	34
38720	PINE FLT	3	34
34539	GWF_GT1	1	32
34541	GWF_GT2	1	32
34433	GWF_HEP2	1	32
34431	GWF_HEP1	1	32
34642	KINGSBUR	1	32
34650	GWF-PWR.	1	32
34640	ULTR.PWR	1	30
34671	KRCDPCT1	1	30
34672	KRCDPCT2	1	30
34648	DINUBA E	1	30
34616	KINGSRIV	1	29

34646	SANGERCO	1	28
34624	BALCH 1	1	28
34344	KERCKHOF	1	24
34344	KERCKHOF	2	24
34344	KERCKHOF	3	24
34308	KERCKHOF	1	24
34636	FRIANTDM	2	18
34636	FRIANTDM	3	18
34636	FRIANTDM	4	18
34658	WISHON	1	17
34658	WISHON	2	17
34658	WISHON	3	17
34658	WISHON	4	17
34631	SJ2GEN	1	16
34633	SJ2GEN	1	16
34301	CHOWCOGN	1	15
34485	FRESNOWW	1	13
34600	HELMS 1	1	13
34602	HELMS 2	1	13
34604	HELMS 3	1	13
34608	AGRICO	2	12
34608	AGRICO	3	12
34608	AGRICO	4	12
34332	JRWCOGEN	1	11
34322	MERCEDFL	1	10
34320	MCSWAIN	1	10
34306	EXCHQUER	1	10
34179	MADERA_G	1	8
34334	BIO PWR	1	7

Herndon Sub-area

The most critical contingency is the loss of the Herndon 230/115 kV bank 1 overlapped with Kerckhoff II generator out of service. This contingency could thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 847 MW (which includes 49 MW of QF generation and 225 MW of Muni generation) in 2008 as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical single contingency for the Herndon sub-area is the loss of the Herndon 230/115 kV bank 1, which could thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of

639 MW (which includes 49 MW of QF generation and 225 MW of Muni generation) in 2008.

Effectiveness factors:

The following table has units within Fresno area that are relatively effective to the above-mentioned constraint. All units in Fresno not listed or units outside of this area have smaller effectiveness factors.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34308	KERCKHOF	1	34
34344	KERCKHOF	1	33
34344	KERCKHOF	2	33
34344	KERCKHOF	3	33
34624	BALCH 1	1	31
34646	SANGERCO	1	29
34672	KRCDPCT2	1	29
34671	KRCDPCT1	1	29
34640	ULTR.PWR	1	29
34616	KINGSRIV	1	28
34648	DINUBA E	1	26
34642	KINGSBUR	1	23
38720	PINE FLT	1	21
38720	PINE FLT	2	21
38720	PINE FLT	3	21
34610	HAAS	1	21
34610	HAAS	2	21
34612	BLCH 2-2	1	20
34614	BLCH 2-3	1	20
34433	GWF_HEP2	1	12
34431	GWF_HEP1	1	12
34301	CHOWCOGN	1	9
34608	AGRICO	2	6
34608	AGRICO	3	6
34608	AGRICO	4	6
34332	JRWCOGEN	1	-8
34485	FRESNOWW	1	-15
34600	HELMS 1	1	-16
34602	HELMS 2	1	-16
34604	HELMS 3	1	-16

McCall Sub-area

No requirements because of the McCall 230/115kV #1 transformer bank replacement by May 2008.

Henrietta Sub-area

The most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 followed by the loss 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 Local Capacity ~~Requirement~~ Need of 141 MW in 2008 (which includes 24 MW of QF generation and 27 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this area.

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 Local Capacity ~~Requirement~~ Need of 32 MW in 2008 (which includes 24 MW of QF generation).

Effectiveness factors:

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

Merced Sub-area

The most critical contingencies is the double line outage of the Wilson – Atwater 115 kV #1 and #2 lines, which could thermally overload the Wilson – Merced 115 kV #1 and #2 lines. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 87 MW (which includes 6 MW of QF generation and 81 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

The only unit in this sub-area JRWCOGEN is needed therefore no effectiveness factor is required.

Fresno Area Overall Requirements:

2008	QF/Selfgen	Muni	Market	Max. Qualifying

	(MW)	(MW)	(MW)	Capacity (MW)
Available generation	204	292	2495	2991

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [18]	2212	0	2212
Category C (Multiple) [19]	2274	108	2382

7. Kern Area

Area Definition

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

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

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

1) Wheeler Ridge is out Lamont is in
2) Kern PP 230 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-Weedpach 60 kV line
3) Wheeler Ridge-San Bernard 60 kV line

The substations that delineate the Weedpatch sub-area are:

1) Wheeler Ridge is out Tejon is in

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

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

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

2008 total busload within the defined area: 1308 MW with 16 MW of losses resulting in a total (load plus losses) of 1324 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BDGRCK_1_UNITS	35029	BADGERCK	9.11	42.67	1	Kern PP		QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	39.91	1	Kern PP		QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	41.56	1	Kern PP		QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	0.73	1	Kern PP		QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	7.74	1	Kern PP		QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	29.32	1	Kern PP		QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	5.45	1	Kern PP		QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	46.81	1	Kern PP		QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.09	1	Kern PP		QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	45.00	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.47	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.48	2	Kern PP		QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	39.67	1	Kern PP		QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	33.75	1	Kern PP		QF/Selfgen
MIDSUN_1_UNITA1	35034	MIDSUN +	9.11	22.00	1	Kern PP		Market
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	42.99	1	Kern PP		QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	50.61	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	35.39	1	Kern PP		QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	45.58	1	Kern PP		QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	9.78	1	Kern PP		QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.00	1	Kern PP		QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.00	2	Kern PP		QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	30.87	1	Kern PP		QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	30.64	1	Kern PP		QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	20.46	1	Kern PP		QF/Selfgen

N/A	35056	TX-LOSTH	4.16	9.00	1	Kern PP	No NQC - historical data	QF/Selfgen
KRNCNY_6_UNIT	35018	KERNCNYN	9.11	9.22	1	Weedpatch	Monthly NQC - used August for LCR	Market
RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.11	6.15	1	Weedpatch		QF/Selfgen

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 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 448 MW in 2008 (includes 609 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of Kern PP #5 230/115 kV transformer bank, which could thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 259 MW in 2008 (includes 609 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35066	PSE-BEAR	1	21
35027	HISIERRA	1	21
35029	BADGERCK	1	21
35023	DOUBLE C	1	21
35058	PSE-LVOK	1	21
35026	KERNFRNT	1	21
35028	OILDALE	1	21
35046	SEKR	1	21
25062	DISCOVERY	1	21
35036	MT POSO	1	15
35035	ULTR PWR	1	14
35052	CHEV.USA	1	5

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 – Weedparch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 38 MW in 2008 (includes 6 MW of QF generation and 23 MW of area deficiency) as the minimum generation 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.

Kern Area Overall Requirements:

2008	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	615	31	646

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [20]	259	0	259
Category C (Multiple) [21]	463	23	486

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

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

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

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

Total 2008 busload within the defined area is 19,409 MW with 226 MW of losses and 22.5MW pumps resulting in total load + losses + pumps of 19,648 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
CABZON_1_WINDA1	28280	CABAZON	33	10.86	1	Eastern	Monthly NQC - used August for LCR	Wind
CHINO_2_QF	24024	CHINO	66	12.09	1	Eastern		QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	40.06	1	Eastern		QF/Selfgen
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00	1	Eastern		MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00	2	Eastern		MUNI
DEVERS_1_QF	24815	GARNET	115	64.02	1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.74	1	Eastern		MUNI

DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.74	2	Eastern		MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.66	3	Eastern		MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.66	4	Eastern		MUNI
ETIWND_2_QF	24055	ETIWANDA	66	17.76	2	Eastern		QF/Selfgen
ETIWND_6_MWDETI	24055	ETIWANDA	66	18.55	1	Eastern		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	18.55	1	Eastern		Market
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	Eastern		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	Eastern		Market
INDIGO_1_UNIT 1	28190	WINTECX2	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 2	28191	WINTECX1	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 3	28180	WINTEC8	13.8	42.00	1	Eastern		Market
INLAND_6_UNIT	24071	INLAND	13.8	30.00	1	Eastern	No NQC - historical data	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	39.59	1	Eastern		QF/Selfgen
NA	24111	PADUA	66	0.00	1	Eastern		QF/Selfgen
NA	24214	SANBRDNO	66	0.00	1	Eastern		QF/Selfgen
NA	24214	SANBRDNO	66	0.00	2	Eastern		QF/Selfgen
NA	24826	INDIGO	115	0.00	1	Eastern		QF/Selfgen
NA	25632	TERAWND	115	0.00	1	Eastern		Wind
NA	25633	CAPWIND	115	0.00	1	Eastern		Wind
BUCKWD_Y_WINTCV	25634	BUCKWIND	115	0.00	1	Eastern		Wind
NA	25635	ALTWIND	115	0.00	1	Eastern		Wind
NA	25636	RENWIND	115	0.00	1	Eastern		Wind
NA	25637	TRANWIND	115	0.00	1	Eastern		Wind
NA	25639	SEAWIND	115	0.00	1	Eastern		Wind
NA	25640	PANAERO	115	0.00	1	Eastern		Wind
NA	25645	VENWIND	115	0.00	1	Eastern		Wind
NA	25646	SANWIND	115	0.00	1	Eastern		Wind
NA	28020	WINTEC6	115	0.00	1	Eastern		Wind
NA	28060	SEAWEST	115	0.00	1	Eastern		Wind
NA	28060	SEAWEST	115	0.00	2	Eastern		Wind
WHTWTR_1_WINDA1	28061	WHITEWTR	33	0.00	1	Eastern		Wind
NA	28260	ALTAMSA4	115	0.00	1	Eastern		Wind
PADUA_6_QF	24111	PADUA	66	7.25	2	Eastern		QF/Selfgen
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	225.07	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	225.07	1	Eastern		Market
VALLEY_2_QF	24160	VALLEYSC	115	6.73	1	Eastern		QF/Selfgen
VALLEY_7_UNITA1	24229	VALLEY-S	115	1.94	1	Eastern		QF/Selfgen
VISTA_6_QF	24902	VSTA	66	0.08	1	Eastern		QF/Selfgen
VISTA_6_QF	24902	VSTA	66	0.08	2	Eastern		QF/Selfgen
NA	24242	RERC1G	13.8	48.00	1	Eastern	No NQC - Pmax	Market
NA	24243	RERC2G	13.8	48.00	1	Eastern	No NQC - Pmax	Market
NA	24244	SPRINGEN	13.8	44.00	1	Eastern	No NQC - Pmax	Market
NA	28041	TOT037C1	19.5	405.00	1	Eastern	No NQC - Pmax	Market
NA	28042	TOT037C2	19.5	405.00	2	Eastern	No NQC - Pmax	Market
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	24018	BRIGEN	13.8	35.00	1	Western, Barre	No NQC - historical data	Market
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	62.63	1	Western, Barre		QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	62.63	2	Western, Barre		QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	62.63	3	Western, Barre		QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	62.63	4	Western, Barre		QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	31.31	5	Western, Barre		QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	31.31	6	Western, Barre		QF/Selfgen
BRDWAY_7_UNIT 3	28007	BRODWYSC	13.8	65.00	1	Western, Barre		MUNI
CENTER_2_QF	24203	CENTER S	66	25.27	1	Western		QF/Selfgen
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.91	1	Western, Barre		QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.92	2	Western, Barre		QF/Selfgen
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.65	1	Western		QF/Selfgen
ELLIS_2_QF	24197	ELLIS	66	0.13	1	Western		QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, Barre		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, Barre		Market
GLNARM_7_UNIT 1	28005	PASADNA1	13.8	22.30	1	Western, Barre		MUNI
GLNARM_7_UNIT 2	28006	PASADNA2	13.8	22.30	1	Western, Barre		MUNI
GLNARM_7_UNIT 3	28005	PASADNA1	13.8	44.83	1	Western, Barre		MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42	1	Western, Barre		MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.27	1	Western, Barre		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	2	Western, Barre		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	3	Western, Barre		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	29.00	1	Western, Barre		Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western, Barre	No NQC - historical data	QF/Selfgen
HINSON_6_SERRGN	24139	SERRFGEN	13.8	25.90	1	Western, Barre		QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.80	1	Western, Barre		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Barre		Market
HNTGBH_7_Unit 3	24167	HUNT3 G	13.8	225.00	3	Western, Barre		Market
HNTGBH_7_Unit 4	24168	HUNT4 G	13.8	227.00	4	Western, Barre		Market
LAFRES_6_QF	24073	LA FRESA	66	5.38	1	Western		QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.85	1	Western		QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	44.67	1	Western, Barre		QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.43	1	Western		QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.47	1	Western		QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	45.00	1	Western, Barre	No NQC - historical data	QF/Selfgen
NA	24027	COLDGEN	13.8	0.00	1	Western, Barre	No NQC - historical data	Market
NA	24028	DELAMO	66	0.00	1	Western		QF/Selfgen
NA	24060	GROWGEN	13.8	0.00	1	Western, Barre	No NQC - historical data	Market
NA	24208	LCIENEGA	66	0.00	1	Western		QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	4.75	1	Western		QF/Selfgen
PULPGN_6_UNIT	24120	PULPGEN	13.8	35.00	1	Western, Barre	No NQC - historical data	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western, Barre		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western, Barre		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	493.24	7	Western, Barre		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western, Barre		Market
RHONDO_2_QF	24213	RIOHONDO	66	1.50	1	Western		QF/Selfgen
SANTGO_6_COYOTE	24133	SANTIAGO	66	9.99	1	Western, Barre		Market
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1,122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1,124.00	3	Western		Nuclear
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	46.97	1	Western		QF/Selfgen
WALNUT_6_QF	24157	WALNUT	66	7.49	1	Western		QF/Selfgen
NA	24239	MALBRG1G	13.8	43.00	C1	Western, Barre	No NQC - Pmax	Market
NA	24240	MALBRG2G	13.8	43.00	C2	Western, Barre	No NQC - Pmax	Market
NA	24241	MALBRG3G	13.8	50.00	S3	Western, Barre	No NQC - Pmax	Market
NA	24078	LBEACH1G	13.8	63.00	1	Western, Barre	No NQC - Pmax	Market

NA	24170	LBEACH2G	13.8	56.50	2	Western, Barre	No NQC - Pmax	Market
NA	24171	LBEACH3G	13.8	56.50	3	Western, Barre	No NQC - Pmax	Market
NA	24172	LBEACH4G	13.8	56.50	4	Western, Barre	No NQC - Pmax	Market
NA	24173	LBEACH5G	13.8	56.50	5	Western, Barre	No NQC - Pmax	Market
NA	24174	LBEACH6G	13.8	56.50	6	Western, Barre	No NQC - Pmax	Market
NA	24079	LBEACH7G	13.8	63.00	7	Western, Barre	No NQC - Pmax	Market
NA	24080	LBEACH8G	13.8	82.50	8	Western, Barre	No NQC - Pmax	Market
NA	24081	LBEACH9G	13.8	63.00	9	Western, Barre	No NQC - Pmax	Market

Units in yellow can not be found on the base case provided by SCE.

Critical Contingency Analysis Summary

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one Songs unit followed by Paloverde-Devers 500 kV line, which could exceed the approved 6100 MW rating for the South of Lugo path. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 10,~~500~~ 130 MW in 2008 (includes 780 MW of QF, 11 MW of Wind, 508 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area. The extra 370 MW reduction versus the March 9 report was achieved by generation redispatch after the reduction in series compensation for the El Dorado-Lugo 500 kV line from 70% to 35% and also the insertion of the series capacitors on the Imperial Valley-Miguel 500 kV line both available as part of the system readjustment between the two contingencies.

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. Fctr. (%)
24052	MTNVIST3	3	21
24053	MTNVIST4	4	21
28041	TOT037C1	1	21
28042	TOT037C2	2	21
24905	RVCANAL1	1	20
24906	RVCANAL2	2	20
24907	RVCANAL3	3	20
24908	RVCANAL4	4	20

24071	INLAND	1	20
25422	ETI MWDG	1	20
24921	MNTV-CT1	1	20
24922	MNTV-CT2	1	20
24923	MNTV-ST1	1	20
24924	MNTV-CT3	1	20
24925	MNTV-CT4	1	20
24926	MNTV-ST2	1	20
25632	TERAWND	QF	20
28021	WINTEC6	1	20
25634	BUCKWND	QF	20
25635	ALTWIND	Q1	20
25635	ALTWIND	Q2	20
25637	TRANWND	QF	20
25639	SEAWIND	QF	20
25640	PANAERO	QF	20
25645	VENWIND	EU	20
25645	VENWIND	Q2	20
25645	VENWIND	Q1	20
25646	SANWIND	Q2	20
24815	GARNET	QF	20
24815	GARNET	W3	20
24815	GARNET	W2	20
28023	WINTEC4	1	20
28060	SEAWEST	S1	20
28060	SEAWEST	S3	20
28060	SEAWEST	S2	20
28061	WHITEWTR	1	20
28260	ALTAMSA4	1	20
28280	CABAZON	1	20
24242	RERC1G	1	20
24243	RERC2G	1	20
24244	SPRINGEN	1	20
24026	CIMGEN	1	19
24030	DELGEN	1	19
25648	DVLCYN1G	1	19
25649	DVLCYN2G	2	19
25603	DVLCYN3G	3	19
25604	DVLCYN4G	4	19
24140	SIMPSON	1	19
25633	CAPWIND	QF	19
28190	WINTECX2	1	19
28191	WINTECX1	1	19
28180	WINTEC8	1	19
25203	ANAHEIMG	1	18
24066	HUNT1 G	1	15
24067	HUNT2 G	2	15
24167	HUNT3 G	3	15
24168	HUNT4 G	4	15
24129	S.ONOFR2	2	15

24130	S.ONOFR3	3	15
24133	SANTIAGO	1	15
24001	ALAMT1 G	1	14
24002	ALAMT2 G	2	14
24003	ALAMT3 G	3	14
24004	ALAMT4 G	4	14
24005	ALAMT5 G	5	14
24161	ALAMT6 G	6	14
24162	ALAMT7 G	7	14
24063	HILLGEN	1	14
24018	BRIGEN	1	12
24011	ARCO 1G	1	11
24012	ARCO 2G	2	11
24013	ARCO 3G	3	11
24014	ARCO 4G	4	11
24163	ARCO 5G	5	11
24164	ARCO 6G	6	11
24020	CARBOGEN	1	11
24064	HINSON	1	11
24070	ICEGEN	1	11
24078	LBEACH1G	1	11
24170	LBEACH2G	2	11
24171	LBEACH3G	3	11
24172	LBEACH4G	4	11
24173	LBEACH5G	5	11
24174	LBEACH6G	6	11
24079	LBEACH7G	7	11
24080	LBEACH8G	8	11
24081	LBEACH9G	9	11
24139	SERRFGEN	1	11
24062	HARBOR G	1	11
25510	HARBORG4	LP	11
24062	HARBOR G	HP	11
24022	CHEVGEN1	1	10
24023	CHEVGEN2	2	10
24047	ELSEG3 G	3	10
24048	ELSEG4 G	4	10
24094	MOBGEN	1	10
24121	REDON5 G	5	10
24122	REDON6 G	6	10
24123	REDON7 G	7	10
24124	REDON8 G	8	10
24241	MALBRG3G	S3	9
24240	MALBRG2G	C2	9
24239	MALBRG1G	C1	9
24027	COLDGEN	1	9
24060	GROWGEN	1	9
24120	PULPGEN	1	9
28005	PASADNA1	1	7
28006	PASADNA2	1	7

28007	BRODWYSC	1	7

Barre Sub-Area:

The most critical contingency for Barre sub-area within the LA Basin is the loss of the one of Huntington units followed by double line outage of Songs-Santiago 230kV lines, which ~~would thermally overload the Ellis-Barre 230kV line~~could result in voltage collapse. This limiting contingency establishes a ~~local~~ Local ~~c~~Capacity ~~requirement~~ Need of 3,~~220~~100 MW (including 431 MW of QF and 197 MW of Muni generation) in 2008.

Also another critical contingency for the Barre sub-area is the double line outage of Songs-Santiago 230kV lines, which could thermally overload the Ellis-Barre 230 kV line.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff. Fctr. (%)
24066	HUNT1 G	1	63
24067	HUNT2 G	2	63
24167	HUNT3 G	3	63
24168	HUNT4 G	4	63
24133	SANTIAGO	1	63
24018	BRIGEN	1	17
24241	MALBRG3G	S3	10
24240	MALBRG2G	C2	10
24239	MALBRG1G	C1	10
24027	COLDGEN	1	10
24060	GROWGEN	1	10
24120	PULPGEN	1	10
24020	CARBOGEN	1	9
24064	HINSON	1	9
24078	LBEACH1G	1	9
24170	LBEACH2G	2	9
24171	LBEACH3G	3	9
24172	LBEACH4G	4	9
24080	LBEACH8G	8	9
24081	LBEACH9G	9	9
24139	SERRFGEN	1	9
24011	ARCO 1G	1	8
24012	ARCO 2G	2	8
24013	ARCO 3G	3	8
24014	ARCO 4G	4	8
24163	ARCO 5G	5	8

24164	ARCO 6G	6	8
24022	CHEVGEN1	1	8
24023	CHEVGEN2	2	8
24173	LBEACH5G	5	8
24174	LBEACH6G	6	8
24079	LBEACH7G	7	8
24094	MOBGEN	1	8
24062	HARBOR G	1	8
25510	HARBORG4	LP	8
24062	HARBOR G	HP	8
28005	PASADNA1	1	8
28006	PASADNA2	1	8
28007	BRODWYSC	1	8
24047	ELSEG3 G	3	7
24048	ELSEG4 G	4	7
24121	REDON5 G	5	7
24122	REDON6 G	6	7
24123	REDON7 G	7	7
24124	REDON8 G	8	7
24070	ICEGEN	1	5

LA Basin Available Capacity:

2008	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	791	508	2246	8548	12093

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Needed
Category B (Single)[22]	10,~~500~~130	0	10,~~500~~130
Category C (Multiple)[23]	10,~~500~~130	0	10,~~500~~130

LA Basin & North of Lugo Overall Requirements:

Total units and base case Pmax for units in the North of Lugo sub-area:

BUS-NO	NAME	ID	Pmax	Sub-area
28000	HIDEDST1	1	300	North of Lugo
28001	HIDEDCT3	1	170	North of Lugo
28002	HIDEDCT2	1	170	North of Lugo

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

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

28003	HIDEDCT1	1	170	North of Lugo
24703	BLM E7G	7	20	North of Lugo
24704	BLM E8G	8	20	North of Lugo
24705	BLM W9G	9	20	North of Lugo
24708	BORAX I	1	47	North of Lugo
24709	BSPHYD26	26	13	North of Lugo
24710	BSPHYD34	34	15	North of Lugo
24711	CALGEN1G	1	30	North of Lugo
24712	CALGEN2G	2	25	North of Lugo
24713	CALGEN3G	3	25	North of Lugo
24714	ALTA 1G	1	60	North of Lugo
24715	ALTA 2G	2	80	North of Lugo
24718	ALTA31GT	31	65	North of Lugo
24719	ALTA 3ST	3	105	North of Lugo
24720	ALTA41GT	41	65	North of Lugo
24721	ALTA 4ST	4	105	North of Lugo
24726	CSA DIAB	1	30	North of Lugo
24732	KERRGEN	1	3	North of Lugo
24733	KERRMGEE	1	55	North of Lugo
24734	ALTA32GT	32	65	North of Lugo
24735	ALTA42GT	42	65	North of Lugo
24737	LUZ8 G	8	80	North of Lugo
24738	LUZ9 G	9	80	North of Lugo
24740	MC GEN	1	105	North of Lugo
24742	MOGEN G	1	60	North of Lugo
24744	NAVYII4G	4	25	North of Lugo
24745	NAVYII5G	5	25	North of Lugo
24746	NAVYII6G	6	25	North of Lugo
24747	OXBOW G1	1	50	North of Lugo
24751	SEGS 1G	1	20	North of Lugo
24752	SEGS 2G	2	30	North of Lugo
24754	SUNGEN3G	3	34	North of Lugo
24755	SUNGEN4G	4	34	North of Lugo
24756	SUNGEN5G	5	34	North of Lugo
24757	SUNGEN6G	6	35	North of Lugo
24758	SUNGEN7G	7	35	North of Lugo
24783	RUSH	1	30	North of Lugo
24784	POOLUWD	1	30	North of Lugo
	Total 2008		**2455**	

Critical Contingency Analysis Summary

LA Basin & North of Lugo overall:

The most critical contingency within the LA Basin & North of Lugo area is the loss of the Paloverde-Devers 500 kV line followed by the loss of the Eldorado-Lugo 500kV line, which could thermally overload the Victorville-Lugo 500 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 11,750 MW combines capacity in the LA Basin & North of Lugo in 2008 as the minimum generation capacity necessary for reliable load serving capability within this combined area.

The most critical single contingency within the LA Basin & North of Lugo is the loss of the Eldorado-Lugo 500kV line, followed by the loss of Songs unit #3, which could thermally overload the Victorville-Lugo 500 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 10,330 MW combines capacity in the LA Basin & North of Lugo in 2008.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff. Fctr. (%)
28000	HIDEDST1	1	31
28001	HIDEDCT3	1	31
28002	HIDEDCT2	1	31
28003	HIDEDCT1	1	31
24737	LUZ8 G	8	30
24738	LUZ9 G	9	30
24721	ALTA 4ST	4	30
24703	BLM E7G	7	29
24704	BLM E8G	8	29
24705	BLM W9G	9	29
24708	BORAX I	1	29
24742	MOGEN G	1	29
24744	NAVYII4G	4	29
24745	NAVYII5G	5	29
24746	NAVYII6G	6	29
24718	ALTA31GT	31	29
24734	ALTA32GT	32	29
24719	ALTA 3ST	3	29
24720	ALTA41GT	41	29
24735	ALTA42GT	42	29
24754	SUNGEN3G	3	28
24755	SUNGEN4G	4	28
24756	SUNGEN5G	5	28
24757	SUNGEN6G	6	28
24758	SUNGEN7G	7	28
24714	ALTA 1G	1	26
24715	ALTA 2G	2	26
24751	SEGS 1G	1	26

24752	SEGS 2G	2	26
28041	TOT037C1	1	26
28042	TOT037C2	2	26
24905	RVCANAL1	1	25
24906	RVCANAL2	2	25
24907	RVCANAL3	3	25
24908	RVCANAL4	4	25
24921	MNTV-CT1	1	25
24922	MNTV-CT2	1	25
24923	MNTV-ST1	1	25
24924	MNTV-CT3	1	25
24925	MNTV-CT4	1	25
24926	MNTV-ST2	1	25
24242	RERC1G	1	25
24243	RERC2G	1	25
24244	SPRINGEN	1	25
24026	CIMGEN	1	24
24030	DELGEN	1	24
25648	DVLCYN1G	1	24
25649	DVLCYN2G	2	24
25603	DVLCYN3G	3	24
25604	DVLCYN4G	4	24
24052	MTNVIST3	3	24
24053	MTNVIST4	4	24
24071	INLAND	1	24
24140	SIMPSON	1	24
25422	ETI MWDG	1	24
25632	TERAWND	QF	24
25633	CAPWIND	QF	24
28021	WINTEC6	1	24
25634	BUCKWND	QF	24
25635	ALTWIND	Q1	24
25635	ALTWIND	Q2	24
25637	TRANWND	QF	24
25639	SEAWIND	QF	24
25640	PANAERO	QF	24
25645	VENWIND	EU	24
25645	VENWIND	Q2	24
25645	VENWIND	Q1	24
25646	SANWIND	Q2	24
28190	WINTECX2	1	24
28191	WINTECX1	1	24
28180	WINTEC8	1	24
24815	GARNET	QF	24
24815	GARNET	W3	24
24815	GARNET	W2	24
28023	WINTEC4	1	24
28060	SEAWEST	S1	24
28060	SEAWEST	S3	24
28060	SEAWEST	S2	24

28061	WHITEWTR	1	24
28260	ALTAMSA4	1	24
28280	CABAZON	1	24
25203	ANAHEIMG	1	23
24711	CALGEN1G	1	20
24712	CALGEN2G	2	20
24713	CALGEN3G	3	20
24066	HUNT1 G	1	19
24067	HUNT2 G	2	19
24167	HUNT3 G	3	19
24168	HUNT4 G	4	19
24129	S.ONOFR2	2	19
24130	S.ONOFR3	3	19
24133	SANTIAGO	1	19
24001	ALAMT1 G	1	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24005	ALAMT5 G	5	18
24161	ALAMT6 G	6	18
24162	ALAMT7 G	7	18
24740	MC GEN	1	18
25618	PEARBMBP	5	18
25618	PEARBMBP	6	18
25619	PEARBMCP	7	18
25619	PEARBMCP	8	18
24136	SEAWEST	1	18
24733	KERRMGEE	1	18
24063	HILLGEN	1	17
25617	PEARBMAP	1	17
25617	PEARBMAP	2	17
25620	PEARBMDP	9	17
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15
24014	ARCO 4G	4	15
24163	ARCO 5G	5	15
24164	ARCO 6G	6	15
24018	BRIGEN	1	15
24070	ICEGEN	1	15
24173	LBEACH5G	5	15
24174	LBEACH6G	6	15
24079	LBEACH7G	7	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24710	BSPHYD34	34	14
24020	CARBOGEN	1	14
24022	CHEVGEN1	1	14
24023	CHEVGEN2	2	14

24726	CSA DIAB	1	14
24047	ELSEG3 G	3	14
24048	ELSEG4 G	4	14
24064	HINSON	1	14
24078	LBEACH1G	1	14
24170	LBEACH2G	2	14
24171	LBEACH3G	3	14
24172	LBEACH4G	4	14
24080	LBEACH8G	8	14
24081	LBEACH9G	9	14
24094	MOBGEN	1	14
24121	REDON5 G	5	14
24122	REDON6 G	6	14
24123	REDON7 G	7	14
24124	REDON8 G	8	14
24139	SERRFGEN	1	14
24784	POOLUWD	1	13
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
24027	COLDGEN	1	11
24060	GROWGEN	1	11
24120	PULPGEN	1	11

9. Big Creek/Ventura Area

<u>Area Definition</u>

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

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

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

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

7) Vincent is out Santa Clara is in

Total 2008 busload within the defined area is 4,435 MW with 156 MW of losses and 420 MW of pumps resulting in total load + losses + pumps of 4,911 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	18	1	Big Creek		Market
ANTLPE_2_QF	24457	ARBWIND	66	21.8	1	Big Creek		Wind
ANTLPE_2_QF	28506	BREEZE1	12	4.5	1	Big Creek		Wind
ANTLPE_2_QF	28507	BREEZE2	12	8	1	Big Creek		Wind
ANTLPE_2_QF	24460	DUTCHWND	66	14	1	Big Creek		Wind
ANTLPE_2_QF	24458	ENCANWND	66	112.9	1	Big Creek		Wind
ANTLPE_2_QF	24459	FLOWIND	66	40.8	1	Big Creek		Wind
ANTLPE_2_QF	28501	MIDWIND	12	18	1	Big Creek		Wind
ANTLPE_2_QF	24465	MORWIND	66	56	1	Big Creek		Wind
ANTLPE_2_QF	28503	NORTHWND	12	19.4	1	Big Creek		Wind
ANTLPE_2_QF	24491	OAKWIND	66	18	1	Big Creek		Wind
ANTLPE_2_QF	28502	SOUTHWND	12	6.6	1	Big Creek		Wind
ANTLPE_2_QF	28504	ZONDWND1	12	13.2	1	Big Creek		Wind
ANTLPE_2_QF	28505	ZONDWND2	12	12.8	1	Big Creek		Wind
APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	60.5	1	Big Creek		Market
APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	60.5	2	Big Creek		Market
BIGCRK_2_PROJCT	24314	B CRK 4	11.5	48.96	41	Big Creek		Market
BIGCRK_2_PROJCT	24314	B CRK 4	11.5	49.15	42	Big Creek		Market
BIGCRK_2_PROJCT	24315	B CRK 8	13.8	23.70	81	Big Creek		Market
BIGCRK_2_PROJCT	24315	B CRK 8	13.8	42.74	82	Big Creek		Market
BIGCRK_2_PROJCT	24306	B CRK1-1	7.2	19.33	1	Big Creek		Market
BIGCRK_2_PROJCT	24306	B CRK1-1	7.2	20.98	2	Big Creek		Market
BIGCRK_2_PROJCT	24307	B CRK1-2	13.8	20.98	3	Big Creek		Market
BIGCRK_2_PROJCT	24307	B CRK1-2	13.8	30.31	4	Big Creek		Market
BIGCRK_2_PROJCT	24308	B CRK2-1	13.8	49.35	1	Big Creek		Market
BIGCRK_2_PROJCT	24308	B CRK2-1	13.8	50.51	2	Big Creek		Market
BIGCRK_2_PROJCT	24309	B CRK2-2	7.2	18.17	3	Big Creek		Market
BIGCRK_2_PROJCT	24309	B CRK2-2	7.2	19.14	4	Big Creek		Market
BIGCRK_2_PROJCT	24310	B CRK2-3	7.2	16.51	5	Big Creek		Market
BIGCRK_2_PROJCT	24310	B CRK2-3	7.2	17.97	6	Big Creek		Market
BIGCRK_2_PROJCT	24311	B CRK3-1	13.8	34.00	1	Big Creek		Market
BIGCRK_2_PROJCT	24311	B CRK3-1	13.8	34.00	2	Big Creek		Market
BIGCRK_2_PROJCT	24312	B CRK3-2	13.8	34.00	3	Big Creek		Market
BIGCRK_2_PROJCT	24312	B CRK3-2	13.8	39.83	4	Big Creek		Market
BIGCRK_2_PROJCT	24313	B CRK3-3	13.8	37.89	5	Big Creek		Market
BIGCRK_2_PROJCT	24319	EASTWOOD	13.8	201.09	1	Big Creek		Market
BIGCRK_2_PROJCT	24317	MAMOTH1G	13.8	90.83	1	Big Creek		QF/Selfgen
BIGCRK_2_PROJCT	24318	MAMOTH2G	13.8	90.83	2	Big Creek		QF/Selfgen
BIGCRK_2_PROJCT	24323	PORTAL	4.8	9.33	1	Big Creek		Market
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54	1	Big Creek		Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	23.5	1	Big Creek		Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.6	G1	Big Creek		Market

LEBECS_2_UNITS	28052	PSTRIAG2	18	157.6	G2	Big Creek		Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.6	G3	Big Creek		Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.2	S1	Big Creek		Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.8	S2	Big Creek		Market
MONLTH_6_BOREL	24456	BOREL	66	9.24	1	Big Creek		QF/Selfgen
NA	24422	PALMDALE	66	1	1	Big Creek	No NQC - historical data	Market
OMAR_2_UNITS	24102	OMAR 1G	13.8	69.44	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	69.44	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	69.44	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	69.44	4	Big Creek		QF/Selfgen
PANDOL_6_UNIT 1	24113	PANDOL	13.8	27.5	1	Big Creek	No NQC - historical data	QF/Selfgen
PANDOL_6_UNIT 2	24113	PANDOL	13.8	22.4	2	Big Creek	No NQC - historical data	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	55.62	1	Big Creek	No NQC - historical data	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	76.5	1	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	76.3	2	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	76.3	3	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	76.3	4	Big Creek		QF/Selfgen
TENGEN_6_UNIT_1	24148	TENNGEN1	13.8	24.2	1	Big Creek	No NQC - historical data	QF/Selfgen
TENGEN_6_UNIT_2	24149	TENNGEN2	13.8	17.5	2	Big Creek	No NQC - historical data	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.92	1	Big Creek		QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	19.5	1	Big Creek		Market
WARNE_2_UNIT	25652	WARNE2	13.8	19.5	1	Big Creek		Market
NA	24436	GOLDTOWN	66	13	1	Big Creek		Market
NA	28008	LAKEGEN	13.8	11	1	Big Creek		QF/Selfgen
NA	24118	PITCHGEN	13.8	30	1	Big Creek		QF/Selfgen
NA	24152	VESTAL	66	50	1	Big Creek		QF/Selfgen
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215	1	Ventura		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130	3	Ventura		Market
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775	2	Ventura		Market
SNCLRA_6_OXGEN	24110	OXGEN	13.8	48.5	1	Ventura		QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	27.81	1	Ventura	No NQC - historical data	QF/Selfgen
NA	24127	S.CLARA	66	49	1	Ventura		QF/Selfgen

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The 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 Local Capacity ~~Requirement~~ Need of 3658 MW in 2008 (includes 1117 MW of QF and 346

MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit # 1 or #2, which could thermally overload the remaining Sylmar-Pardee #1 or #2 230 kV line. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 3562 MW in 2008 (includes 1117 MW of QF and 346 MW of Wind generation).

Effectiveness factors:

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

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
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
24127	S.CLARA	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
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

Big Creek Overall Requirements:

2008	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1117	346	3933	5396

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[24]	3562	0	3562
Category C (Multiple)[25]	3658	0	3658

10. San Diego Area

<u>Area Definition</u>

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

1) Imperial Valley – Miguel 500 kV Line
2) Miguel – 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

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

The substations that delineate the San Diego Area are:

1) Imperial Valley is out Miguel is in
2) Miguel 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 2008 busload within the defined area: 4799 MW with 117 MW of losses resulting in total load + losses of 4916 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	43.80	1		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	3.50	1		QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	1.00	1		QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	2.50	2		QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPISTRANO	138	4.10	1		QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	8.32	1	Monthly NQC - used August for LCR	Wind
DIVSON_6_NSQF	22172	DIVISION	69	47.00	1		QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	1.00	1		QF/Selfgen
ELCAJN_6_UNITA1	22150	CALPK_EC	13.8	42.20	1		Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	13.00	1		Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1		Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	103.00	1		Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	109.00	1		Market
ENCINA_7_EA4	22240	ENCINA 4	22	299.00	1		Market
ENCINA_7_EA5	22244	ENCINA 5	24	329.00	1		Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.00	1		Market
ESCNDO_6_PL1X2	22257	MMC_ES	13.8	35.50	1		Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	45.50	1		Market
ESCO_6_GLMQF	22332	GOALLINE	69	50.00	1		QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	15.00	1		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	14.00	2		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	14.00	1		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	14.00	1		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	13.00	2		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	15.00	2		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.00	1		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.00	1		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.00	2		Market
KYCORA_7_UNIT 1	22384	KYOCERA	69	0.00	1		QF/Selfgen
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1		Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	46.60	1		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.00	1		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	16.00	2		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	2.70	1		QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	35.10	1		QF/Selfgen
OTAY_6_PL1X2	22617	MMC_OY	13.8	35.50	1		Market
OTAY_6_UNITB1	22604	OTAY	69	2.90	1		QF/Selfgen

PALOMR_2_PL1X3	22262	PENCT1	18	155.42	1		Market
PALOMR_2_PL1X3	22263	PENCT2	18	155.42	1		Market
PALOMR_2_PL1X3	22265	PENST	18	230.63	1		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.40	2		QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	21.90	1		QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	14.10	1		QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	1.10	1		QF/Selfgen
SOBAY_7_GT1	22776	SOUTHBGT	12.5	13.00	1		Market
SOBAY_7_SY1	22780	SOUTHBY1	15	145.00	1		Market
SOBAY_7_SY2	22784	SOUTHBY2	15	149.00	1		Market
SOBAY_7_SY3	22788	SOUTHBY3	20	174.00	1		Market
SOBAY_7_SY4	22792	SOUTHBY4	20	221.00	1		Market
MSSION_2_QF	22532	MURRAY	69	0.20	1	No NQC - historical data	QF/Selfgen
MSSION_2_QF	22680	R.SNTAFE	69	0.80	1	No NQC - historical data	QF/Selfgen
MSSION_2_QF	22496	MISSION	69	2.10	1		QF/Selfgen
MSSION_2_QF	22760	SHADOWR	138	0.10	1	No NQC - historical data	QF/Selfgen
MSSION_2_QF	22008	ASH	69	0.90	1	No NQC - historical data	QF/Selfgen
NA	22625	LKHODG1	13.8	20.00	1	No NQC - Pmax	Market
NA	22626	LKHODG2	13.8	20.00	2	No NQC - Pmax	Market

Critical Contingency Analysis Summary

San Diego overall:

In 2008 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 Palomar Combined-Cycle Power plant (541 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This limiting contingency establishes a Local Capacity ~~Requirement~~ Need of 2957 MW in 2008 (includes 193 MW of QF generation and 8 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.

San Diego Overall Requirements:

2008	QF	Wind	Market	Max. Qualifying

	(MW)	(MW)	(MW)	Capacity (MW)
Available generation	193	8	2758	2959

2008	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[26]	2957	0	2957
Category C (Multiple)[27]	2957	0	2957

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