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Commissioner: Michel Florio

ALJ: David Gamson

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (DMG) (Filed March 22, 2012)

EXCERPT OF CAISO 2007 LOCAL CAPACITY TECHNICAL ANALYSIS REPORT & STUDY RESULTS

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

October 28, 2013

California ISO

2007
LOCAL CAPACITY TECHNICAL ANALYSIS

REPORT
AND STUDY RESULTS

Corrected Version July 18, 2006

Local Capacity Technical Analysis Overview and Study Results

I. Executive Summary

At the February 3, 2006 prehearing conference in Docket R.05-12-013 (*Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program*), the California Independent System Operator Corporation ("CAISO") advised the California Public Utilities Commission ("CPUC") that the Local Capacity Requirement ("LCR") results of its 2007 local capacity technical analysis could be made available within eight weeks after the development of the input assumptions for the study. Following a meet and confer process, Administrative Law Judge Wetzell adopted proposed study assumptions. These assumptions have been incorporated into this "Local Capacity Technical Analysis Study ("2007 LCR Study"), as discussed below. The CAISO has now completed its analysis and therefore provides this 2007 LCR Study to describe the final LCR results and the methodology and criteria used to obtain those results.

This Report provides a description of the 2007 LCR Study objectives, inputs, methodologies and assumptions, and the important policy considerations that are presented by the study results. Specifically, as requested by the Stakeholders and approved by the CPUC, the CAISO has conducted the study to produce local area capacity requirements necessary to achieve three levels of service reliability. These levels of service reliability, which are driven by the transmission grid operating standards to which the CAISO must comply, are set forth on the following table[1]:

[1] This comparison table is explained in detail at Section IV. below. The reader should be aware that the deficiencies identified for certain local areas are driven by capacity requirements in sub-area load pockets discussed at IV.B.

Local Requirements Comparison

	Qualifying Capacity			2007 LCR Requirement Based on Category B Option 1			2007 LCR Requirement Based on Category C with operating procedure Option 2			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	582**	0	**582****	582**	0	**582****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	432	0	**432**	536	53	**589**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	4771**	0	**4771****	6009
Greater Fresno	575	2337	2912	2115	0	**2115**	2151	68	**2219**	2837 *
Kern	978	31	1009	554	0	**554**	769	17	**786**	797*
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**	2620
Total	**8185**	**19379**	**27564**	**22113**	**205**	**22318**	**22468**	**466**	**22934**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay and Greater Bay Area requirements would have been higher by 80 and 570 MW respectively, however two new operating procedures have been received, validated and implemented by PG&E and the CAISO.

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 stored at:

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

The difference between the terms "Qualifying Capacity" and "Net Qualifying Capacity" is that certain units have associated plant load and thus, the "Net Qualifying Capacity" represents the output from the unit after the plant load has been subtracted. However, the LCR Study incorporates the plant load from these units into the "total load" calculation.

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 and nuclear units). The second set is "market" generation. The second column, "2007 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 (Option 1, discussed in Section II.C of this Report). The third column, "2007 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 (Option 2).

The highest service reliability level, based on Performance Criteria-Category C without non-generational solutions to address operating deficiencies (Option 3), can be determined from the table by adding 80 MW to the local capacity requirements for the North Coast/North Bay area (thus raising total 2007 LCR requirements by 80 MW). This exercise removes the new operating procedure provided by PG&E from the analysis in compliance with the Category C reliability standard that relies solely on generation to address identified capacity deficiencies.

As shown on the table above, the study results have important public policy implications. These study results indicate 3 levels of capacity that are necessary to have sufficient capacity in support of 3 levels of service reliability. The reader should appreciate that the differences in levels of capacity have direct implications to the costs and expected levels of reliability that are achieved for customers located within the local areas. Thus, option 1 (performance level B) has a lower level of capacity required and will therefore have an expected lower level of reliability because less capacity is available to the CAISO. Similarly, the operational solutions underlying option 2 (performance level C) provide for less procurement of capacity than option 3 by placing load in the mix of solutions that the CAISO will use to respond to contingencies. This approach may be appropriate where all outages are expected to have short-term affects on the transmission system. Yet, long duration outages would potentially subject load to extended outages. Option 3 also NERC performance level C, results provide the quantity of capacity that would give the CAISO a full set of capacity to respond to contingencies. This level effectively

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reserves the load based operational solutions for major emergencies or contingencies that are not considered in the study criteria and therefore results in an expected higher level of service reliability than the two alternate options.

Public policy decision-makers must choose the appropriate level of service reliability. The information provided in the 2007 LCR Study, including the CAISO's recommendations found at Section II.E. below, can assist with this choice.

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

A. Objectives

Similar to the 2006 Local Capacity Technical Analysis ("2006 LCR Study")[2], the purpose of the2007 LCR Study is to identify specific areas within the CAISO Controlled Grid that have local reliability problems and to determine the generation capacity (MW) that would be required to mitigate these local reliability problems. However, based on input from market participants and at the direction of the CPUC, the 2007 LCR Study identifies different levels of local capacity that correspond to separate performance/reliability criteria related to grid robustness under which the CAISO must plan and operate the grid. This additional information is intended to allow the CPUC to affect the expected level of service reliability that customers of jurisdictional LSEs will receive by dictating the appropriate amount of local capacity that must be procured. In so doing, the CPUC should endeavor to make a decision that seeks to find the appropriate balance between a desired level of service reliability and the cost of installed capacity. The details of the 2007 LCR study, set forth in the following sections, will facilitate the CPUC's ability to make this important decision.

[2] The 2006 LCR Study (Locational Capacity Technical Analysis: Overview of Study Report and Final Results) dated September 23, 2005 was submitted to the CPUC as part of the CAISO's Motion to Augment the Record Regarding Resource Adequacy Phase 2 in R.04-04-003. An Addendum to the 2006 LCR Study was submitted on January 31, 2006. These documents can be found on the CAISO website at: http://www.caiso.com/1788/178883551f690.html and http://www.caiso.com/docs/2004/10/04/2004100410354511659.html

B. Key Study Assumptions

1. Inputs and Methodology

The CPUC directed the CAISO, respondents, and other interested parties to meet and confer with the objective of identifying not more than three alternative sets of input assumptions the CAISO would incorporate into the 2007 LCR Study. The meet and confer session was held on February 17, 2006 and, as noted above, the agreed-upon input scenarios were submitted by the CAISO on February 22, 2006. An errata to the February 22 filing was submitted on March 10, 2006. The following table sets forth a summary of the approved inputs and methodology that have been used in the 2007 LCR Study:

Summary Table of Inputs and Methodology Used in 2007 LCR Study:

Issue:	HOW INCORPORATED INTO THE 2007 LCR STUDY:
Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, 2007 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, 2007
• Load Forecast	Uses a 1-in-10 year summer peak load forecast

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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 historical output values for purposes of the 2007 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 the 2007 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**	The 2007 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, 2007. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCR Study and the resulting LCR published for this third scenario.
Load Pocket:	
• **Fixed Boundary, including limited reference to published effectiveness factors**	The 2007 LCR Study has been produced based on load pockets defined by a fixed boundary. The CAISO was initially planning to publish the effectiveness factors of the generating resources within the defined load pocket as well as the effectiveness factors of the generating resources residing outside the load pocket that had a relative effectiveness factor of no less than 5% or affect the flow on the limiting equipment by more than 5% of the equipment's applicable rating. . However, after subsequent discussions with the Commission and stakeholders, and given the comments in the CPUC Staff Report regarding the limited usefulness of effectiveness factors, the CAISO plans to only publish effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket. If stakeholders want additional effectiveness factor published, the CAISO will defer to the Commission as to what further effectiveness factor data it would like the CAISO to publish.

Further details regarding the 2007 LCR Study methodology and assumptions are provided in Section III, below.

2. Operating Requirements

As was done in the 2006 LCR Study, this study incorporates specific operating requirements, needed in order to prevent voltage collapse or transient instability for the loss of a single transmission element ("N-1") followed by system readjustment and the loss of two transmission lines (common mode failure)[3]. In addition, the LCR Study addresses contingencies where the system suffers the loss of a single transmission element ("N-1"), the system is readjusted and then the loss of an additional transmission element (N-1-1). As reflected in Table 2, the capacity in columns two (Category B) and three (Category C) are identical in at least four of the local areas. This occurs because the capacity necessary to prevent voltage collapse or transient instability for the loss of a single transmission element (N-1) is the same as that necessary for the N-1-1 scenario.

Consistent with NERC standards, after the second N-1 or immediately after the common mode failure load shedding is allowed as long as all criteria (thermal, voltage, transient, reactive margin) are respected. The CAISO planning criteria generally allows for load shedding for the double contingencies. However, the CAISO has, consistent with its Tariff, conducted planning studies that maintain the level of reliability that existed prior to its formation. This is referred in the CAISO Tariff as "Local Reliability Criteria," which, along with NERC Planning Standards discussed below, form the CAISO's "Applicable Reliability Criteria" The CAISO is under an obligation to implement Local Reliability Criteria, unless modified pursuant to agreement with the relevant Participating Transmission Owner ("PTO"). As such, to the extent a PTO's pre-CAISO standards did not allow for load shedding for common corridor and/or double circuit tower line outages, the CAISO has maintained that practice to assure that the level of reliability that prevailed before the CAISO was formed would be maintained and the CAISO remains in compliance with its obligations.

[3] These failures include a double circuit tower and the loss of two 500kv lines that are located in the same corridor.

C. Grid Reliability and Service Reliability

The 2007 LCR Study is intended to provide the CPUC with the "tools" needed to make the important threshold policy decision as to the desired level of service reliability within the CAISO Control Area, ultimately establishing the appropriate amount of local generation capacity CPUC jurisdictional LSEs must procure. The options produced by the study for consideration by the CPUC are discussed in further detail in this overview section of the report, and also in the technical discussion of the study itself. However, to assist the CPUC in analyzing the study results and the options that are being presented, it is important that the CPUC and other parties understand how the CAISO distinguishes "service reliability" from "grid reliability" and where the respective CAISO/CPUC responsibilities lie. Both service and grid reliability form the basis of the reliability standards consumers within the CAISO Control Area will receive.

1. 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 primarily apply to the bulk, interconnected electric system in the Western 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.[4] 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

[4] Pub. Utilities Code § 345

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the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected bulk electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The NERC Planning Standards are organized by Performance Categories. For instance, one category could require that the grid operator not only ensure grid integrity is maintained under certain adverse system conditions, e.g., security, but also that all customers continue to receive electric supply 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. Here, it would be up to the regulatory agency of service reliability, i.e. the CPUC, to determine the appropriate level of service reliability under the system conditions defined by the differing levels of NERC planning standards.

Given the foregoing, one of the ambiguities identified in the recent CPUC workshops is the fact that several performance categories make up the NERC Planning Standards and, therefore, Applicable Reliability Criteria. The various parties perceived this as potentially permitting the CAISO to procure generation, in its backstop role, to satisfy all performance categories. Rather, the CAISO believes it is the role of the CPUC to determine the level of service reliability it wishes to establish for the ratepayers. To further addresses this concern, it is important to again describe the Performance Categories, which are critical to understanding how the CPUC and CAISO can work together.

a. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, the 2007 LCR is based on NERC Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. These Performance Levels can be described as follows:

i. Performance Criteria- Category B

Category B describes the system performance that is expected 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 a certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met and that facilities are returned to normal ratings when either the element that was lost is returned to service or system adjustments are made within the appropriate time limits.

However, 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, pre-contingency load-shedding, 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.[5]

ii. Performance Criteria- Category C

Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the 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."

2. Service Reliability

The CAISO is responsible for grid reliability in accordance with the NERC performance criteria described above. However, grid reliability can be maintained at service reliability levels that may be unacceptable to the CPUC and end user customers. The 2007 LCR Study presents the CPUC with relevant information to select a level of service reliability that also fulfills grid reliability. Specifically, the study specifies varying generation capacity levels for each local capacity area based on Performance criteria- Categories B and C, with the inclusion of suitable non-generation solutions raised by the PTOs to address contingency conditions as described under Performance Criteria- Category C.

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[5] 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.

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As shown by the study results, where the NERC Planning Standards do not allow for load shedding, grid reliability and service reliability are the same and establish a minimum level of capacity needed to meet the CAISO's statutory obligation.[6] Where it is not possible to develop operating solutions to ensure "controlled" interruption of service, in these cases generation will also be required to meet Applicable Reliability Criteria to avoid the potential of load shedding in anticipation of a contingency. Where feasible operational solutions and/or generation procurement amounts affect the level of service to customers, service reliability is implicated and different levels of service reliability may be possible.

D. The Three Options Presented By The 2007 LCR Study

The 2007 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 for 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.[7]

[6] The NERC Planning Standards reflect a "deterministic" analysis that captures the "robustness" of the grid. In many NERC subregions, service reliability is understood as the probability of disconnecting firm load due to a resource deficiency. Control areas in the Western Electricity Coordinating Council, including the CAISO, do not currently have sufficient information to apply a probabilistic reliability analysis to transmission or planning studies. However, the CAISO has consistently recommended that the CPUC move to a loss of load probability approach as a means by which to consider alternative solutions while still planning to a desired level of service reliability.
7 This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

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

Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (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 as the CAISO operators prepare for the second contingency. However, the customer load will be interrupted in the event the second contingency occurs.

3. Option 3- Meet Performance Criteria Category C through Pure Procurement

Option 3 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 only. No load based operational solutions are incorporated into this scenario. Therefore, this results in a "pure capacity" procurement scenario.

E. The CPUC's Responsibilities and The CAISO's Recommendation

The CPUC is responsible for determination of the appropriate level of service reliability to end-use customers within each CAISO-identified local capacity area. The CPUC may meet this responsibility by exercising its jurisdiction over load serving entities to compel procurement of generation or demand resources to meet the option selected. The CPUC may also wish to allow the load serving entity to choose planned or controlled load interruption options.[8] The CPUC should impose appropriate penalties for LSEs that fail to comply with the procurement levels that are necessary to meet its established applicable reliability criteria standard. Finally, in its determination of an acceptable service reliability level, the CPUC should

[8] However, such automatic load shedding schemes or operating procedures implementing manual load shedding options must be acceptable to the CAISO, i.e., the load to be shed is demonstrable, verifiable, and appropriately dispatchable.

explicitly understand the implications associated with contingent events as well as the potential that customers will receive different levels of service reliability based on the service reliability level selected for each local capacity area.

As the grid operator, the CAISO recommends that Option 2 be selected as the service reliability standard. Option 2 identifies a potential service reliability that reflects generation capacity set forth in (2) above, adjusted for any feasible operating solution identified by a PTO prior to the study and approved by the CAISO. On a day-to-day basis the CAISO has traditionally operated the network based on the N-1-1 contingency, with operating solutions developed with the PTOs. Should the CPUC choose Option 2, and to the extent a load shedding solution proposed by a PTO is isolated solely in the service territory of a CPUC load serving entity, the CAISO has indicated the appropriateness of such operating procedure to the CPUC in this study.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

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Table 1: 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 normal limits.

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

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contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 1. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

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

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

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

3 Applicable Rating – Based on ISO Transmission Register or facility upgrade plans.

4 Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

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

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

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

2. Post Transient Load Flow Assessment:

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

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

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

3. Stability Assessment:

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

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

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

B. Methodology for Determining Zonal Requirements

A key part of the CAISO's study for determining capacity requirements in transmission-constrained areas includes **zonal requirements** to ensure that sufficient generation capacity (in MWs) exists within each large zone so that transmission constraints between zones do not threaten reliability. The analysis of zonal requirements was discussed in the CPUC workshops and the 2006 Local Capacity Technical Analysis (page 5), but the methodology for determining these zonal requirements was not explained in detail.

The CAISO's methodology for determining these zonal requirements is designed so the operating reserves within each zone meet the WECC Minimum Operating Reliability Criteria (MORC) for operating reserves.[9]

[9] *MORC states "Prudent operating judgment shall be exercised in distributing operating reserve, taking into account effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements."*

The determination of these zonal requirements is dependent upon key assumptions:

- **Forecasted Load:** Consistent with CAISO Planning Standards, the CAISO proposes a forecasted zonal load level that represents the 1-in-5-year peak conditions (more specifically the zonal area "coincident" peak.) For future studies the CAISO expects to use the CEC's 1-in-5 year peak load forecasts.

- **Import Capability:** the maximum MW amount that is assumed can be imported into a zone. This can be calculated based on the maximum historical imports into a zone, plus the anticipated increase in import capability due to transmission upgrades in effect for the time period being analyzed. This includes capacity from outside the CAISO Control Area and capacity between the zones, e.g. Path 26.

- **Outages**: the amount of generation that may be unavailable within a zone due to unforeseen circumstances that require immediate maintenance. Assuming a peak load, this assumption would encompass forced outages as well as a very small amount of planned outages.

- **Recovery from a Single Worst Contingency:** enough operating reserve to recover from the most severe single contingency without relying on firm load shedding. This total reserve capacity is based on the set of assumptions for peak load conditions. Existing industry standards do not permit shedding firm load to address a single contingency.

The zonal requirement (i.e., the amount of MWs needed within each region) is determined simply by calculating the sum of the operating reserves for recovery from a single worst contingency, the historical outage data, and the 1-in-5-year peak forecast, subtracted by the import capability:

1 in 5 zonal Load forecast + Historical outage data + Recovery from single worst contingency – Import Capability = Zonal Requirement

Zonal requirements define the amount of generation (in MWs) that should exist within a region to ensure the system's ability to withstand a single worst contingency. The CAISO should focus on the 500kV system only between three major zones: NP15, NP15+ZP26, and south of Path 26 (SP26.) These are historically defined regions of the CAISO Controlled Grid where inter-zonal transmission constraints have been prone to deficiencies. Generation within all the local areas within these zones would count toward meeting a zonal requirement.

C. Load Forecast

1. System Forecast

The load forecast at the system as well as PTO levels originates from California Energy Commission (CEC). This most recent 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 muni forecasts. The melding process consists of two parts. Part 1 deals with the PTO load. Part 2 deals with the muni 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

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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 muni forecasts provided to the PTOs for the purposes of their base cases were used for this study.

3. Comparison between the 1-in 5 and 1-in-10 local load forecast

As a rule of thumb, this difference translates into a corresponding one-for-one reduction in the LCR -- (the MWs of capacity needed in that local area) -- provided that the area constraint is driven by a thermal problem AND assuming that the load and generation have roughly the same effectiveness factors.

The exact reduction in LCR results (using a less stringent 1-in-5-year instead of the 1-in-10-year load forecast) could be different due to the load growth characteristics specific to each local area. If the local area constraints are non-linear, like voltage or dynamic problems, or if the effectiveness factors between the generators and load within the same area are significantly different relative to the worst thermal constraint, then the difference in LCR results will not mirror the difference in load forecast.

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Table 2: 2007 Local Area Load Forecast 1-in 5 vs 1-in-10

	Peak Load (1 in 10) (MW)	Peak Load (1 in 5) (MW)	Difference (MW)	Difference (%)
Humboldt	197	196	1	0.5
North Coast/North Bay	1,513	1,475	38	2.5
Sierra	1,841	1,805	36	2.0
Stockton	1,267	1,252	15	1.2
Greater Bay	9,633	9,509	124	1.3
Greater Fresno	3,154	3,004	150	4.8
Kern	1,209	1,174	35	2.9
LA Basin	19,325	18,809	516	2.7
San Diego	4,742	4,610	134	2.8
Total	**42,881***	**41,834***	**1,049**	**2.4**

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

The peak load forecast is one key variable in the determination of the LCR that meets the established criteria. In comparing the 1-in-5-year load analysis with the 1-in-10-year standard, a general conclusion that could be drawn is that the difference in required MWs for most of the local areas and sub-areas analyzed in this report would not be huge. An analysis of each local area and the unique contingencies within each area would be necessary to determine the exact difference in LCR's.