BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program	)))))	R.05-12-013

PROPOSAL OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION REGARDING LOCAL RESOURCE ADEQUACY REQUIREMENTS

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Dated: January 31, 2006

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The California Independent System Operator Corporation ("CAISO") respectfully submits its 2006 LCR Technical Study ("LCR Study") and supporting addendum as its local resource adequacy requirements ("RAR") proposal in accordance with D.05-10-042, the *Order Instituting Rulemaking* (R.05-12-013), filed December 15, 2005 ("OIR"), and the ruling of Administrative Law Judge Wetzell pursuant to Rule 48 of the Commission's Rules of Practice and Procedure, dated January 31, 2006.

I. Introduction

The CAISO strongly supports the Commission's efforts to ensure reliable and cost-effective electricity supply in California through refinement and augmentation of its adopted RAR program. As we collaboratively address the centerpiece of this OIR, the development and refinement of local RAR, the CAISO emphasizes its shared values with the Commission regarding the long-term objectives of its RAR program, namely that (1) investment required for reliability actually occurs, (2) resources are available to the grid when and where needed, (3) capacity is available when the system is stressed, and (4) least cost principles are upheld. California's success in creating a viable and sustainable RAR program is tied to our ability to meet these critical objectives.

The goal of this filing is to clarify the underpinnings of the CAISO's LCR Study and urge the Commission to adopt the CAISO's LCR Study methodology. The CAISO's LCR Study addresses all of the Commission's objectives identified above and directly facilitates the realization of having capacity available when the system is stressed and making capacity available when and where needed. As such, this filing highlights these objectives and outlines:

- The benefits of adopting the reliability criteria used in the LCR Study
- The risks of relying on sub-optimal reliability standards
- The critical steps and timing required to develop the 2007 LCR Study

II. Discussion

A. CAISO LCR Study is Based on Proven Reliability Criteria

The CAISO's LCR Study relies on prudent reliability criteria and planning standards that reflect the day-to-day realities of operating the CAISO Controlled Grid and adhere to the widely understood and proven deterministic approach to grid planning sanctioned by the Western Electricity Coordinating Council ("WECC") and the North American Electric Reliability Council ("NERC").

To maintain today's level of reliability, the CAISO's LCR Study is appropriately based on the CAISO's ability to recover from overlapping contingencies while staying within the existing equipment and path ratings, and it uses a one-in-ten year peak summer load forecast, which is standard practice for local area grid planning in California.

The results reflected in the CAISO's LCR Study are closely aligned with the minimum planning and operating requirements that determine the resource commitments made under both the CAISO's Reliability Must Run ("RMR") and, notably, the FERC Must-Offer Waiver Process. An important clarification about the CAISO's LCR Study is that it does not apply criteria beyond existing grid planning standards; rather it reflects the operational reality that RMR alone cannot achieve the Commission's objective that generation be available when and where needed.[1] The existing RMR criteria constitute a subset of the applicable CAISO Grid Planning Standards and are insufficient in identifying the necessary quantity of capacity that is required to maintain the minimum reliability standards currently used for day-to-day operations.

1. Complies with Defined and Accepted Planning Standards

The technical analysis conducted by the CAISO for determining LCR for 2006 conform to the CAISO's Grid Planning Process and Standards, which have been developed

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[1] It is important to use similar assumptions for the amount of generation committed when comparing the local capacity requirement in the LCR Study to current RMR designations. The local capacity requirements in the LCR Study also include the operational requirements that are currently being met through the FERC Must-Offer Obligation.

in consultation with Participating Transmission Owners, Utility Distribution Companies and other market participants.[2] The CAISO's Planning Standards consistently rely on national and regional grid planning standards, in particular the NERC and WECC Planning Standards. The CAISO's Planning Standards build from, rather than duplicate, standards that were developed by WECC and NERC. The CAISO's Planning Standards have the added benefit that they:

- Address specifics not covered in the NERC/WECC Planning Standards.
- Provide interpretations of the NERC/WECC Planning Standards specific to the CAISO Grid.
- Clearly identify where specific criteria should be adopted that are more stringent than the NERC and, or WECC planning standards.

2. Allows for Recovery from Overlapping Contingencies

Transmission system reliability studies evaluate system impacts due to the loss of one or two elements in the transmission system under peak generation and load conditions. As was done in this LCR Study, the CAISO determined if its system could withstand single or multiple contingency events under realistically stressed conditions without pre-contingency interruptible or firm load shedding in the local pockets.

The CAISO's LCR Study incorporates specific requirements that allow for recovery from simultaneous or overlapping contingencies that require generators inside the load pocket be used to prevent violating existing industry standards and criteria. In other words, the CAISO is planning for contingencies where the system suffers the loss of a single element, the system is readjusted without pre-contingency interruptible or firm load shedding, and then the loss of the next credible transmission contingency occurs.

Any adopted standard different than this must meet the Commission's objective of having capacity available when the system is stressed. When translated to load pockets, this means there are sufficient MWs, whether generation or permissible and accepted load dropping capability or schemes, within the load pocket to keep the system within emergency thermal limits and acceptable voltage limits and prevent the possibility of voltage collapse and, or transient instability.

[2] CAISO Tariff § 3.2.1.2.

3. Incorporates Critical 500 kV Path Mitigation Criteria

Under WECC/NERC standards, the CAISO must account for contingencies on the entire CAISO Controlled Grid, including maintaining flow levels below all established path ratings, including 500 kV.

The CAISO's previous RMR Studies, in conjunction with Local Area Reliability Service ("LARS") designations, never considered 500kV path mitigation. The assumption was that all 500 kV path flows would be met through available market mechanisms; however, this was not fully realized and the CAISO had to rely on generation from the FERC Must-Offer process to satisfy the 500 kV limits. The RMR study only evaluated single contingencies on the 500 kV system and below, and as such, the RMR study was too narrow in scope to account for the replacement of both RMR and Must-Offer generation. For the CAISO's LCR Study, it would be imprudent for the CAISO to overlook this critical detail. Accordingly, the CAISO has incorporated this criterion into the CAISO's LCR Study and recommends the Commission do so as well in order to meet the Commission's objectives that investment for reliability occurs and capacity is available when and where needed.

4. Uses the Most Appropriate Load Forecast

The CAISO appropriately uses a one-in-ten year peak summer load forecast as a benchmark for local reliability. Parties have expressed concern that this criterion is overly stringent. However, the CAISO believes it is appropriate and should be the Commission's adopted standard for the following reasons:

- A one-in-ten year peak forecast has been used as an established standard practice for transmission planning studies within California for local areas for determining if and what reinforcement of the transmission system is needed.
- A one-in-ten year peak summer load forecast is superior to a one-in-five year forecast since it better accommodates the absence of load and temperature diversity in small load pockets.
- Use of a lower one-in-five year forecast does not provide a determination of local area generation resources that would be comparable to a transmission reinforcement project and, thus, would lead to a continuing gap in having sufficient generation resources available during real-time operation.
- It would put the generation and demand side at a disadvantage during the

resource procurement process because transmission projects are routinely approved using a one-in-ten year load forecast for local areas.

- Using anything less than this load forecast for local areas would create a gap that the CAISO would likely need to fill with its backstop authority

If a load forecasting methodology change is contemplated or a different standard adopted, such a change should be coordinated through the CAISO Grid Planning Standards Committee as any such change could have impacts beyond this proceeding.[3]

In summary, the CAISO's believes the use of a one-in-ten year peak summer load forecast for the LCR Study is appropriate and would better estimate the local capacity requirements in the load pockets and is more consistent with prior CPUC directives intended to diminish reliance on CAISO procurement authority and reestablish load-serving entities ("LSEs") as primarily responsible for procuring the resources necessary to meet the needs of their customers.[4]

5. Incorporates the Contribution from Non-Generation Alternatives

The 2006 CAISO's LCR Study incorporates all approved transmission projects, operating procedures and special protection systems ("SPS") into its analysis, and thus the local capacity requirements presented are net of the benefits provided by these non-generation alternatives. Any future transmission projects, operating procedures or SPS alternatives would be identified and evaluated through the annual expansion plans. Future preferred non-generation alternatives would be included in the CAISO transmission expansion plan, which would also be included in future resource adequacy proceedings at the CPUC.

B. Risks of Relying on Sub-optimal Reliability Standards

Reliability is often a political and social issue that has very real and significant consequences if managed imprudently. As California has experienced, loss of load results in both financial and political fallout that is increasingly unacceptable to California consumers, especially given ever-increasing expectations of assured reliability. The CAISO urges the Commission to adopt the CAISO's input assumptions and the criteria set forth in the

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3 See, *California ISO Planning Standards*, February 7, 2002, p. 8.

4 See, *Interim Opinion Regarding Electricity Issues,* D.04-07-028 (July 7, 2004).

CAISO's LCR Study by supporting:

- The ability to recover from overlapping contingencies
- The need to maintain flow levels below all established path ratings, including 500 kV
- A one-in-ten year peak summer load forecast for determining local capacity requirements

The CAISO cautions the Commission against readily adopting single contingency only outcomes. If it does, the CAISO will likely need contingency plans, including pre-contingency load shedding, given that in many load pockets, any scheduled or unscheduled outage of a transmission or generation facility will result in immediate classification as an N-1 condition. In addition, significant market price volatility could result if the CAISO is chronically short in the load pockets and must dispatch energy resources to meet its operational requirements in these areas. Adopting a standard that complies with both the single and double contingencies would better ensure sufficient capacity exists in the load pockets and should help minimize reliance on high spot market prices to encourage availability.

In summary, the CAISO believes accepting any lower standards for the possibility of achieving minimal upside benefits is not worth the potentially costly downside risks.

C. Critical Steps and Timing Required to Develop a New LCR Study

The CAISO is confident in the results of its 2006 LCR Study and believes that it incorporates all of the appropriate reliability criteria and planning standards that ensure capacity is available when and where needed. The CAISO intends to deliver to the Commission a new LCR Study for 2007; however, it is important the Commission understand the process necessary to develop a new study.

The most important component of the LCR Study is the underlying assumptions that are input into the planning model. The CAISO is hopeful the Commission will adopt the criteria used in the CAISO's 2006 LCR Study which will help ensure consistency between the 2006 and 2007 LCR Studies and will best meet the Commission's RAR program objectives.[5] Thus, it is imperative this Commission promptly establish a durable set of study inputs that the CAISO can use as the basis for this and future LCR Studies and allow the CAISO to effectively manage and deliver a timely LCR Study for 2007.[6]

Once the Commission adopts a set of input study assumptions, the CAISO will require a minimum of two (2) weeks to build the base cases for the local areas and six (6) weeks to run simulations, retrieve and interpret data, and write the final report. This minimum required time does not reflect an important period for stakeholder review and comment, which should be incorporated into the overall process.

Finally, if the resulting studies require further revision, the time to reprocess the base cases can take anywhere from two (2) weeks, if changing only contingency assumptions, to six (6) weeks if load data or other, more fundamental base case assumptions are changed. All of these estimated times are based on the assumption that the study will be for year 2007 only and not a multi-year study.

III. Conclusion

For the foregoing reasons, the CAISO respectfully requests that the Commission adopt the CAISO's LCR Study, including the methodology and reliability criteria contained therein. The reliability benefits of doing so are clear and strongly support the agreed to long-term objectives for creating a sustainable and viable RAR program.

January 31, 2006

Respectfully Submitted:

By: ____________________
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5 Substantively, the ability to recover from overlapping contingencies, the need to maintain flow levels below all established path ratings, including 500 kV, and a one-in-ten year peak summer load forecast for determining local capacity requirements.

6 The Commission should be aware, however, that to the extent the study assumptions result in LCR results that do not permit the CAISO to meet its Applicable Reliability Criteria, the CAISO will utilize available procurement authority.

ATTACHMENT 1

California ISO

LOCAL CAPACITY TECHNICAL ANALYSIS

OVERVIEW OF STUDY REPORT AND FINAL RESULTS

September 23, 2005

Table of Contents

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

As part of the Phase 2 Resource Adequacy workshops, the California Public Utilities Commission ("CPUC") requested the California Independent System Operator Corporation ("CAISO") to perform a technical analysis to determine the amount of generation capacity (MW) required to reliably serve load within transmission constrained areas of the grid. [1] This final overview documents the technical basis for a Local Capacity Requirement ("LCR") that meets this objective of ensuring reliable service by applying consistent criteria across the CAISO Control Area. The methodology and criteria used by the CAISO and the final LCR results are described below.[2]

Application of the LCR criteria to the CAISO Controlled Grid for 2006 resulted in an aggregate requirement for all Local Capacity Areas of 23,420 MW. (See Table 2 below). This total LCR consists of 16,230 MW of market only generation and 7,190 MW of Municipal and Regulatory Must-take (State, Federal, QFs and nuclear units) generation that already are part of some LSE portfolio and have an assured revenue stream. By comparison, the CAISO's Local Area Reliability Service ("LARS") technical analysis used to procure Reliability Must Run ("RMR") contracts results in 10,415 MW of market only generation and 7,190 MW of Municipal and Regulatory Must-Take generation, which in the study is assumed to be on-line. Thus, the difference for the entire CAISO Controlled Grid is 5,815 MW.

It is important to understand why the results of the LCR study exceed the quantity of capacity procured through the LARS technical analysis. There are three primary factors contributing to this differential:

1. **The LCR criteria reflect the standards under which the CAISO must operate the CAISO Controlled Grid. The LARS criteria do not, and are not intended to, achieve this objective**. The LCR allow the CAISO to operate the grid with an ability to recover from overlapping contingencies in which a major facility is lost from service (N-1), the system is then readjusted, and then another major facility (N-1 or common mode N-2) is lost from service. (See Table 1 below). *These are the actual conditions under which the CAISO currently must operate the CAISO Controlled grid*. The LARS study criteria simply look at a single or N-1 contingency. Therefore, the

[1] *Interim Opinion Regarding Resource Adequacy,* D.04-10-035 (Oct. 28, 2004) at p. 47.
[2] This report was originally issued in draft form on June 23, 2005: http://www.caiso.com/docs/2005/06/24/2005062408465116859.pdf. A revised report was issued on July 26, 2005: http://www.caiso.com/docs/09003a6080/36/b0/09003a608036b0c1.pdf

current RMR or LARS criteria constitute a small subset of the applicable CAISO Grid Planning Standards.

2. **The LCR, but not LARS, considers 500kV path mitigation.** The CAISO must account for contingencies on the entire CAISO Controlled Grid, including established 500 kV path ratings. However, given the narrow focus of LARS, the RMR technical analysis only evaluates single contingencies on the 500 kV system and below; 500 path mitigation was realized through markets only. As such, a significant portion of the discrepancy arises from the fact that the LARS analysis and the resulting MW amount of RMR contracts fail to account for generation committed, pursuant to the existing Federal Energy Regulatory Commission-imposed Must Offer Obligations ("MOO"), to satisfy the operational requirements the CAISO must follow, in order to stay within all 500 kV path ratings, and which are reflected in the LCR.

3. **Change of load forecast from one-in-five peak load to a one-in-ten peak load.** The LARS technical process was, in part, developed as a compromise among the CAISO and market participants. An element of this compromise was the use of a one-in-five year peak load forecast. However, for local load pockets, the CAISO believes a one-in-ten year load forecast is more appropriate because of the absence of load and temperature diversity in small load pockets.[3] As such, generation procurement, transmission expansion and load demand side management are all using the same criteria.

The use of different load forecast levels explains much of the change between RMR and LCR for the SDG&E service territory. Moreover, it is important to use similar assumptions for the amount of generation being committed when comparing the LCR to the 2006 RMR designations. As noted, the LCR requirements include operational requirements now met, in significant part, but not wholly, through generation dispatched under the existing MOO. The published 2006 RMR designations do not include generation dispatched under MOO for such purposes. Therefore, the amount of generation that would have been committed under MOO should be added to the RMR designation total to produce a fair comparison. In this regard, the LCR is consistent with prior CPUC directives intended to diminish reliance on CAISO procurement authority and reestablish load-serving entities ("LSEs") as primarily responsible for procuring the resources necessary to meet the needs of their costumers.[4]

[3] For example, the SDG&E transmission system has been consistently studied in the transmission expansion plans with a 1-in-10 load forecast to address these issues.
[4] See, *Interim Opinion Regarding Electricity Issues,* D.04-07-028 (July 7, 2004).

For 2006, this RMR/MOO total is approximately 15,145 MW. (See, Table 2.) Thus, the amount of market generation capacity required for the 2006 LCR will exceed the RMR/MOO total by approximately 7% [(16,230 – 15,145)/15,145].[5]

The CAISO believes this study reflects the necessary and appropriate levels of resources for an effective local capacity obligation.

II. Stakeholder Process and General Background

The parameters of this study were initially presented and discussed with stakeholders at a CPUC workshop conducted in Folsom on January 25, 2005. The proposed methodology and criteria for this Local Capacity Area technical study were published as part of a "Straw Proposal" document that was distributed to the CPUC R.04-04-003 service list of workshop participants. This document has since been posted on the CAISO website at:

http://www.caiso.com/docs/2005/06/22/2005062214371421107.pdf

The preliminary results of this study were presented to stakeholders at a meeting on June 29, 2005. These preliminary results are posted on the CAISO website at:

http://www.caiso.com/docs/2005/06/24/2005062408465116859.pdf

The CAISO also reviewed revisions to this preliminary report with stakeholders during conference calls on July 20 and August 1, 2005. A number of suggestions from these stakeholder discussions are incorporated within this improved overview. This overview also identifies the transmission lines into these Local Capacity Areas and the substation facilities that encircle or are included within each Local Capacity Area. The CAISO believes this information can be used to geographically define each Local Capacity Area and to assign specific local capacity obligations to the LSEs that serve load within these geographic boundaries. The CAISO anticipates that the CPUC will establish such an allocation mechanism through the CPUC's upcoming orders on Resource Adequacy.

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[5] The estimated MOO numbers for 2005 and 2006 in Table 2 below, represent the capacity (in MWs) actually committed for MOO during year 2004 from generating units (other then RMR) in the Eastern and Western sub-area of the Los Angeles ("LA") Basin, less the units retired or expected to retire and with the addition of reasonably anticipated new units that would be subject to the current MOO process. FERC-MOO capacity is not included for other Local Capacity Areas because of the historic absence of significant MOO waiver denials in those areas to address local reliability concerns. Further, changes to the transmission system in 2005, i.e., South of Lugo upgrades, Path 26 upgrades and the addition of Miguel-Mission #2, have greatly reduced the daily quantity of capacity and overall costs of MOO in the LA Basin. This daily reduction may or may not change the data included in Table 2 because the same units may be committed in 2005, but simply at a more infrequent rate. Thus, while 7% may somewhat underestimate the overall procurement difference, any comparison of the generation actually required under present system operation and under LCR must account for MOO capacity.

The final results of the study are expressed in MWs that are meant to define the minimum amount of capacity that is needed in each Local Capacity Area for reliable operation of the CAISO Controlled Grid.   The CAISO is providing an attachment that lists the generating units that would be eligible for meeting the MW amounts that must be procured within each Local Capacity Area. The CAISO envisions a process where it provides the aforementioned list of substations and the appropriate generators to LSEs on an annual basis to guide them in meeting the LCR.

III. Description of Local Area Requirements under Resource Adequacy

The regulatory framework adopted by the CPUC in the October 28th 2004 decision on resource adequacy, D.04-10-035, includes three distinct categories by which generators would be assessed for their ability to deliver the output of electricity, and thereby count toward meeting an LSE's resource adequacy obligation. These three categories are briefly described below.

Deliverability of generation to the aggregate of load
This category measures the ability of generators to provide energy to the CAISO transmission system at peak load while not being limited by the transmission system or dispatch of other resources in the vicinity. The CAISO conducted a baseline study assessing the deliverability of existing generators and presented the preliminary results to stakeholders on May 9, 2005. An additional phase of this baseline study will be conducted soon to account for new generation projects with approved interconnection studies. Thereafter the deliverability of new resources will be assessed incrementally as part of the CAISO's technical studies to ensure the safe and reliable interconnection of new generators.

Deliverability of imports
This category identifies the generation capacity (MW) amounts that should be considered deliverable from outside the CAISO Controlled Grid through import paths. For this initial assessment, the CAISO analyzed data that reflected the historical use of intertie points between the CAISO's system and neighboring systems. The preliminary results for the deliverability of imports category also were presented to stakeholders on May 9, 2005.

Deliverability to load within transmission constrained areas
This category of deliverability is the focus of the study documented by this overview report. It identifies the generation capacity (MW) that must be procured within the LCA to reliably serve the load located LCAs within the CAISO Controlled Grid.

All three categories of deliverability are assumed to be part of the resource adequacy rules that will be implemented in June 2006. It is expected the CPUC will require that specific resources must be deliverable to the aggregate of load in order to count as qualified capacity meeting an LSE's overall resource adequacy obligation. Generating units within load sub-area that qualify as deliverable to load within a transmission constrained Local Area could count both toward the Local Capacity Area obligation and the overall RA obligation for an LSE.

As indicated in documents reviewed at previous CPUC workshops,[6] the CAISO's study for determining capacity requirements in transmission constrained areas includes analysis of the 500 kV system between three major zones: NP15, NP15+ZP26, and SP26. The determination of these zonal requirements is intended to ensure that sufficient capacity exists within each large zone so that transmission constraints between zones do not threaten reliability.

Finally, the CAISO intends to perform this Local Capacity Area technical analysis annually. However, the transmission constraints that give rise to the Local Capacity Requirement may be relieved with the identification and construction of additional transmission infrastructure through the CAISO's transmission planning process. While this is certainly feasible, the CAISO anticipates that the boundaries of Local Capacity Areas will be fairly static over a 3-5 year time horizon and the minimum amount of capacity procured within each Local Capacity Area should remain reasonably stable. In short, the Local Capacity requirement for each Local Capacity Area may decline as transmission improvements relieve constraints, or increase proportionally as load grows; however, LSEs should be able to anticipate these changes over the long-term in order to strategically plan how to reach their procurement targets.

IV. The Study

A. Objectives

The purpose of the CAISO's Local Capacity Technical Analysis was 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. The results of this overview show:

A. The minimum generation capacity (in MWs) that must be available within each Local Capacity Area;

B. Transmission lines and substations that encircle each Local Capacity Area, from which a geographical description can be drawn to identify which load is encompassed within each sub-area;

C. Generating units that are located within each Local Capacity Area that would be eligible to count toward meeting the LCR for that area.

[6] http://www.caiso.com/docs/2005/06/22/2005062214371421107.pdf.

In some of the Local Capacity Areas, there are insufficient generation resources to mitigate the reliability criteria violations that occur. These Local Capacity Areas are highlighted in the Overview to provide guidance on where new transmission infrastructure or new generation resources could be added.

B. Key Study Assumptions

Many of the assumptions related to generation adopted for this study are similar to the assumptions made for RMR studies, including the availability of “Must Take” resources at their contract ratings, the dispatch of hydro generation and the explicit representation of municipal, state, federal and QF generating units in the power flow base cases.

The CAISO utilized the “2006 CAISO Controlled Grid – Summer Peak” as the starting base case for the local area power flows. To complete the local area component of this study, this base case was adjusted to reflect a one-in-ten-year peak load forecast for each local area as provided to the ISO by the Participating Transmission Owners (“PTOs”). To complete the zonal component of this study, the base case was adjusted to reflect a one-in-five-year peak load forecast for each zone. The lower forecast is acceptable on a zonal level due to higher diversity of load and temperature at peak time and consistent with the transmission expansion plans provided by the 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 2006.

C. Methodology and Criteria

The CAISO’s study followed the proposed methodology and criteria that were published as part of a “Straw Proposal” document that was distributed to the CPUC R.04-04-003 service list of workshop participants. A comparison of the proposed LCR criteria to the existing RMR and WECC/NERC criteria is shown in Table 1. As can be seen from this table, the proposed LCR criteria, while more extensive than the existing RMR criteria, is consistent with the CAISO Grid Planning criteria. A brief description of how the CAISO applied the criteria in its study is provided below.

<u>Performance Level A</u>
This a normal operating condition with no overloads and all voltages within their normal operating limits.

<u>Performance Level B</u>
This performance level incorporates N-1 contingencies that could include the loss of a single generator, a single transmission line or a single transformer bank. This standard requires enough generation so that the system avoids voltage collapse or transient instability as a result of these potential N-1

scenarios. The transmission system also should remain within emergency thermal limits and acceptable voltage limits. Following this N-1 contingency the generation must be sufficient to allow for operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC.

Performance Level C

This performance level requires sufficient generation for the system to absorb the loss of a generating unit or transmission facility, readjust to a normal operating state, and then suffer the loss of another transmission facility. This standard requires a MW amount within that Local Capacity Area sufficient to keep the system within emergency thermal limits and acceptable voltage limits, as well as avoiding voltage collapse and transient instability.

Performance Level C also incorporates common mode failure N-2 contingencies that could include the simultaneous loss of two transmission lines or two generating units. This standard requires enough generation so that the system avoids voltage collapse or transient instability as a result of these potential N-2 scenarios. The transmission system also should remain within emergency thermal limits and acceptable voltage limits.

Operating Requirements

This study also incorporated specific operating requirements, needed in order to prevent voltage collapse or transient instability for "N-1, followed by N-2" contingencies. This would include contingencies where the system suffers the loss of a single generating unit or transmission line, the system is readjusted and then the simultaneous loss (common mode failure)[7] of two transmission lines occurs.

Consistent with NERC standards, after the second N-1 or immediately after the common mode N-2 load shedding is allowed as long as all criteria (thermal, voltage, transient, reactive margin) are respected. However, while the CAISO criteria generally allows for load shedding for the N-1, N-2 contingencies, the CAISO has also maintained the level of reliability that existed prior to its formation. 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.

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

D. Table 1: Criteria Comparison

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	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		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		
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 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.

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.

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.

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.

Loss of Load Probability:

Loss of Load Probability ("LOLP") is a study methodology that can be used to establish the level of capacity required in each local area by performing a probabilistic analysis to achieve a specified probability for loss of load. In the established Eastern markets, a one-event in ten years LOLP methodology is used to determine LSE capacity obligations. The LOLP approach provides a potentially more uniform reliability result than the proposed deterministic approach. In the future, if the LOLP approach is determined to be a more desirable approach, then the LOLP analysis will be incorporated into the criteria if and when a criteria and methodology for applying it has been developed. Any LOLP criteria and methodology will need to be reviewed by stakeholders and approved by the CPUC. Until such time, the LOLP approach will not be used to establish LSE capacity requirements, and the deterministic approach defined above will be used.

V. Summary of Final Locational Capacity Requirement Study Results

The LCR results reflect two sets of generation. The first set is “market only” generation. The second 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 CAISO’s technical analyses for both RMR and LCR studies have assumed this second set of generation to be available and on-line. However, the CAISO’s previous RMR documentation did not specifically identify the amount of this generation in its documentation primarily because, by definition, RMR is only the amount of market only generation that is needed to address local reliability issues. As such, the total LCR cannot be compared to the RMR/Must Offer total unless the set of Municipal/Regulatory Must-take generation is appropriately accounted for in the comparison.

Within this overview, LCR is defined as the amount of generating capacity that is required within a Local Capacity Area to reliably serve the load located within this area. Therefore, the “Total LCR” for any given Local Capacity Area includes both the market only generation identified for RAR procurement and the Municipal and Regulatory Must-take generation that is assumed to be on-line.

The results of the CAISO’s analysis are summarized in the following two tables.

A. Table 2: Local Requirements Comparison

Table 2
Local Requirements Comparison: RMR vs. LCR

Local Area Name	2005 RMR (MW)	2006 RMR (MW)	2006 market only LCR (MW)	2006 Total LCR (MW)
Humboldt	124	125	126	162
North Coast / North Bay	517	273	518	658
Sierra	384	468	808	1770*
Stockton	57	100	244	440*
Greater Bay	4000	4000	4600	6009
Greater Fresno	1558	1691	2529	2837 *
Kern	N/A	N/A	171	797*
LA Basin	1390 4700 (MOO)	1389 4730 (MOO)	4800	8127

San Diego	2019	2369	2434	2620
Total	**14749**	**15145**	**16230**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR

The "2005 RMR" and "2006 RMR" columns represent the total market generation requirements, based on the RMR criteria, with the assumption that all Muni, State, Federal, QFs and nuclear units are on-line and available to serve load. For the LA Basin (total between the east and west sub-areas), those columns also include capacity committed historically by the CAISO under the existing FERC-MOO to satisfy planning and operational criteria. The estimated MOO numbers for 2005 and 2006, represents the capacity (in MWs) actually committed for MOO during year 2004, from generating units (other then RMR) in the Eastern and Western sub-area of the LA Basin, less the units retired or expected to retire and with the addition of reasonably anticipated new units that would be subject to the current MOO process. FERC-MOO capacity is not included for other Local Capacity Areas because of the historic absence of significant MOO waiver denials in those areas to address local reliability concerns.[8]

The "2006 market only LCR" column represents the total market generation requirements, based on the LCR criteria, with the assumption that all Muni, State, Federal, QFs and nuclear units are on-line and available to serve load. This column compares the MW requirements under the RMR versus the LCR criterion using the same generation assumptions. The CAISO believes these results compared with those in the previous column are the most important to view when considering the overall impact of transitioning to LCR from the existing RMR process. It should be noted that for the LA Basin the total of 4800 MW represents the minimum generation requirement prescribed by technical studies and assumes the most effective generation facilities are on-line. In contrast, the MOO historical data (2004) underlying the 2006 RMR/MOO column reflects waiver denials across the entire year, not at a specific point in time. As such, there is a great chance that different sets of units were used at different times to address similar reliability concerns because of unit availability. This accounts, in part, for the higher MW quantity in the 2006 RMR column than in the 2006 market only LCR column.

The last column represents the "2006 Total LCR requirement" that all LSEs have to procure in local areas under the CPUC Locational Capacity Requirements. This last column includes all units needed to maintain system reliability. The difference between the "2006 market only LCR" and the "2006 Total LCR" is all the Muni, State, Federal, QFs and nuclear units that were considered on-line and available to serve load in all previous RMR studies.

[8] See footnote 4 above for further details.

B. Table 3: Local Capacity Requirements vs. Peak Load and Local Area Generation

Table 3 Local Capacity Requirements vs. Peak Load and Local Area Generation that need to be served by all LSE in that local area					
Local Area Name	**2006 Total LCR (MW)**	**Peak Load (1 in10) (MW)**	**2006 LCR as % of Peak Load**	**Total Dependable Local Area Generation (MW)**	**2006 LCR as % of Total Area Generation**
Humboldt	162	195	83%	168	96%
North Coast/North Bay	658	1,494	44%	888	74%
Sierra	1,770	1,791	99%	1,713	103%**
Stockton	440	924	48%	458	96%**
Greater Bay	6,009	9,485	63%	7,591	79%
Greater Fresno	2,837	3,117	91%	2,651	107%**
Kern	797	1,209	66%	839	95%**
LA Basin	8,127	18,839	43%	10,309	79%
San Diego	2,620	4,578	57%	2,957	89%
Total	**23,420**	**41,632***	**56%***	**27,574**	**85%**

* 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 it implies that in order to comply with the criteria, at summer peak, load must be shed immediately after the first contingency.

Table 3 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. This table also indicates where new transmission projects, new generation additions or demand side management programs would be most useful in order to reduce the dependency on existing (mostly old and inefficient) local area generation.

VI. Summary of Results by Local Area

A. Humboldt Area

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 multiple contingency establishes a Local Capacity Requirement of 162 MW (includes 36 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

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 115 kV
2) Humboldt 115 kV
3) Kekawaka 60 kV
4) Ridge Cabin 60 kV

B. North Coast / North Bay Area

The North Coast/North Bay Area is composed of two sub-areas and the generation requirements within them. The most critical contingency for the Eagle Rock-Fulton Sub-area is described by 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 the Corona-Penngrove section of the Corona-Lakeville 115 kV line #1. This limiting contingency establishes a Local Capacity Requirement of 319 MW (includes 79 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The transmission tie facilities coming into this sub-area are:

1) Fulton-Lakeville 230 kV line #1
2) Fulton-Ignacio 230kV line #1
3) Cortina 230/115 kV Transformer #1
4) Lakeville-Sonoma 115 kV line #1
5) Corona-Lakeville 115 kV line #1
6) Willits-Garberville 60 kV line #1

The substations that delineate the Eagle Rock-Fulton sub-area are:

1) Fulton 230 kV
2) Corona 115 kV
3) Sonoma 115 kV
4) Cortina 115 kV
5) Laytonville 60 kV

The most critical contingency for the Lakeville Sub-area would be outages on Vaca-Dixon-Lakeville 230 kV line #1 and the Crockett-Sobrante 230 kV line #1. The sub-area area limitation is thermal overloading of the Tulucay-Vaca Dixon 230 kV line #1. This limiting contingency establishes a Local Capacity Requirement of 658 MW (includes 140 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR requirement for Eagle Rock/Fulton sub-area can be counted toward fulfilling the requirement of Lakeville sub-area
.

The transmission tie lines into this sub-area are:

1) Vaca Dixon-Lakeville 230 kV line #1
2) Tulucay-Vaca Dixon 230 kV line #1
3) Lakeville-Sobrante 230 kV line #1
4) Ignacio-Sobrante 230 kV line #1
5) Ignacio-Fulton 230 kV line #1
6) Lakeville-Fulton 230 kV line #1
7) Lakeville-Corona 115 kV line #1
8) Lakeville-Sonoma 115 kV line #1

The substations that delineate the Lakeville sub-area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Tulucay 230 kV
4) Lakeville 115 kV

C. Sierra Area

The most critical contingencies in the Sierra Area are 1) the loss of the Poe-Rio Oso 230 kV line #1 and the Colgate – Rio Oso 230 kV line #1, and 2) the loss of the Cresta-Rio Oso 230 kV line #1 and the Colgate – Rio Oso 230 kV line #1. The area limitation is thermal overloading of the Table Mt-Rio Oso 230 kV line #1.
This limiting contingency establishes a Local Capacity Requirement of 1770 MW (includes 962 MW of QF and Muni generation and an LCR Deficiency of 143 MW)

as the minimum capacity necessary for reliable load serving capability within this area.

This area has numerous sub-areas (minimum six – see RMR report), however since all units are needed to maintain the overall requirement, no additional detailed sub-area analysis is needed at this time.

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

1) Table Mountain 60 kV
2) Table Mountain 230 kV
3) Big Bend 115 kV
4) Drum 115 kV
5) Tamarack 60 kV
6) Brighton 230 kV
7) Rio Oso 230 kV
8) Gold Hill 230 kV

D. Stockton Area

The requirement for this area is driven by the requirement for the Tesla-Bellota Sub-area and Lockeford Sub-area.

The critical contingency for the Tesla-Bellota Sub-area is the loss of Tesla-Tracy 115 kV and Tesla-Schulte 115 kV #1. The capacity needed for this sub-area is 449 MWs. The area limitation is thermal overloading of the Tesla-AEC section of Tesla-Kasson-Manteca 115 kV line

.

This limiting contingency establishes a Local Capacity Requirement of 449 MW (includes 229 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

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

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

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

1) Tesla 115 kV
2) Bellota 115 kV

The critical contingency for the Lockeford Sub-area is the loss of Lockeford-Industrial 60 kV and Lockeford-Lodi #2 60 kV. The capacity needed for this sub-area is 92 MWs. The area limitation is thermal overloading of the Lockeford-Colony section of the Lockeford-Lodi #1 60 kV line
.
This limiting contingency establishes a Local Capacity Requirement of 92 MW (includes 2 MW of QF generation)
as the minimum capacity necessary for reliable load serving capability within this area.

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 is:

1) Lockeford 60 kV

E. Greater Bay Area

The most limiting contingencies within the Greater Bay Area are an over-lapping outage of the Tesla-Metcalf 500 kV line with the Tesla-Newark #1 230 kV line. The amount of generation required within the Greater Bay Area is predicated on staying within the emergency rating of the Tesla-Newark #2 230 kV line and specifically that portion of the line consisting of bundled 1113 AL conductor emanating from Newark Substation. This requires 6,009 MW of generation resources (includes 1409 MW of QF and Muni generation) within the Greater Bay area.

There are four sub-areas within this area where there is dependence on specific generation facilities to mitigate a reliability problem. These areas are:

San Francisco Sub-area - Per the CAISO Revised Action Plan for SF, all Potrero units (365 MW) will continued to be required until completion of the plan as it is presently described.

Oakland Sub-area - The most critical contingency is an outage of either the C-X 115 kV cable or the D-L 115 kV cable (with one of the Oakland CT's off-line)
. The sub-area area limitation is thermal overloading of either the C-X 115 kV cable or the D-L 115 kV cable
.
This limiting contingency establishes a Local Capacity Requirement of 100 MW (includes 50 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

San Jose Sub-area - The most critical contingency is an outage between Metcalf and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line).
The sub-area area limitation is thermal overloading of the Metcalf-Llagas 115 kV line. As documented within an 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 of 100 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

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 of 2363 MW (includes 763 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

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-Contra Costa Sub 230 kV

6) Peabody-Contra Costa P.P. 230 kV
7) Kelso-Brentwood 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-Tracy #1 230 kV
14) Tesla-Tracy #2 230 kV
15) Tesla-Ravenswood 230 kV
16) Tesla-Metcalf 500 kV
17) Moss Landing-Metcalf 500 kV
18) Moss Landing-Metcalf #1 230 kV
19) Moss Landing-Metcalf #2 230 kV
20) Green Valley-Morgan Hill #1 115 kV
21) Green Valley-Morgan Hill #2 115 kV
22) Oakdale TID-Newark #1 115 kV
23) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Moraga 230 kV
4) Lambie SW Sta 230 kV
5) Kelso 230 kV
6) Contra Costa P.P. 230 kV
7) Pittsburg 230 kV
8) Tesla 230 kV
9) Metcalf 500 kV
10) Moss Landing 500 kV
11) Morgan Hill 115 kV
12) Newark 115 kV

F. Greater Fresno Area

Wilson Sub-area: The most critical contingency for the Wilson sub-area is the loss of the Wilson - Melones 230 kV line, which would thermally overload the Wilson - Warnerville 230 kV line

.

This limiting contingency establishes a Local Capacity Requirement of 1560 MW (which includes 105 MW of muni generation and 203 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

At least 120 MWs of the 1560 MW must come from the Helms generating units.

Herndon Sub-area: The most critical contingency for the Herndon sub-area is the loss of the Herndon 230/115 kV bank 1, which would thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity Requirement of 1,207 MW (which includes 153 MW of QF generation and 50 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

McCall Sub-area: The most critical contingency for the McCall sub-area is the loss of Kings River – Sanger – Reedley 115 kV line, which would thermally overload the McCall – Wahtoke 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 1,346 MW (which includes 60 MW of QF generation and 36 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Henrietta Sub-area: Within the Henrietta sub-area a minimum 40 MW generation capacity is needed to mitigate the Henrietta 230/70 kV bank overload.

Merced Sub-area: The most critical contingencies for the Merced sub-area is the double line outage of the Wilson – Atwater 115 kV #1 and #2 lines, which would thermally overload the Wilson – Merced 115 kV #1 and #2 lines. This limiting contingency establishes a Local Capacity Requirement of 172 MW (which includes 105 MW of muni generation, 4 MW of QF generation and 60 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

In conclusion for the Greater Fresno Area, the total accumulative Local Capacity Requirement for the five sub-areas is 4323 MW. Because of the overlapping LCR MWs requirements among the sub-areas, the total aggregate LCR requirement for the Greater Fresno Area is 2837 MW (includes 105 MW of muni generation, 203 MW of QF generation and 146 MW of total three sub-area deficiency).

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Henrietta Tap 1 230 kV
2) Gates-Henrietta Tap 2 230 kV
3) Gates #1 230/115 kV Transformer Bank
4) Los Banos #3 230/70 Transformer Bank
5) Los Banos #4 230/70 Transformer Bank
6) Panoche-Gates #1 230 kV
7) Panoche-Gates #2 230 kV
8) Panoche-Coburn 230 kV
9) Panoche-Moss Landing 230 kV
10) Panoche-Los Banos #1 230 kV
11) Panoche-Los Banos #2 230 kV

12) Panoche-Dos Amigos 230 kV
13) Warnerville-Wilson 230 kV
14) Wilson-Melones 230 kV
15) Corcoran – Alpaugh - Smyrna 115 kV
16) Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

1) Los Banos 230 kV
2) Gates 230 kV
3) Panoche 230 kV
4) Wilson 230 kV
5) Alpaugh 115 kV
6) Coalinga 70 kV

G. Kern Area

Kern PP Sub-area: The most critical contingency for the Kern PP sub-area is the outage of the Kern PP 230/115 kV transformer Bank 5 and the Kern PP – Kern Front 115 kV line, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity Requirement of 771 MW (which includes 618 MW of QF generation and 132 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Weedpatch Sub-area: The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line and the Wheeler Ridge – Tejon 70 kV line, which would 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 of 26 MW (which includes 8 MW of QF generation and 10 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

In conclusion, for the Kern Area, the total accumulative and aggregate Local Capacity Requirement for the two sub-areas is 797 MW (which includes 626 MW of QF generation and 142 MW of total two sub-area deficiency).

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) Temblor – San Luis Obispo 115 kV line

These sub-stations form the boundary surrounding the Kern PP sub-area:

1) Midway 115 kV
2) Kern PP 115 kV
3) Wheeler Ridge 115 kV
4) Temblor 115 kV

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

1) Wheeler Ridge 115/60 kV Bank
2) Wheeler Ridge 230/60 kV Bank

These sub-stations form the boundary surrounding the Weedpatch sub-area:

1) Wheeler Ridge 60 kV

H. LA Basin Area

The total market generation requirement for the LA Basin is 4,800 MW. This area's generation requirement is defined by two sub-areas (the Western and Eastern Sub-areas). The combined Local Area Requirement is 8127 MW of which 3327 MW includes the San Onofre Nuclear Power Plant and QF and Muni generation.

The critical contingency for the in the Western Sub-area is the loss of Vincent - Rio Hondo 230 kV line #2, followed by loss of Mesa - Vincent 230 kV line. The sub-area area limitation is thermal overloading of the Mesa-Antelope 230 kV line
.

The two critical contingencies in the Eastern Sub-area are: (1) Loss of Devers – Valley 500 kV line, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3, and (2) Loss of one San Onofre Nuclear Generator, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3. The sub-area area limitation is low area post-transient voltage associated with voltage collapse.

The Western and Eastern sub-area contingencies require 4800 MW as the minimum amount of generating capacity necessary for reliable load serving capability within these sub-areas. 1925 MW of this capacity is needed in the Eastern sub-area, and the rest (2875 MW) is needed in the Western sub-area.

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre - Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #1, #2 & #3 500 kV Lines
4) Sylmar LA - Sylmar S #1, #2 & #3 230/230 kV Transformers
5) Sylmar S - Pardee #1 & #2 230 kV Lines
6) Vincent - Mesa Cal #1 230 kV Line
7) Antelope - Mesa Cal #1 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee #1 230 kV Line
10) Devers - Valley #1 500 kV Line
11) Devers #1 & #2 500/230 kV Transformers
12) Devers - Coachelv # 1 230 kV Line
13) Mirage - Ramon # 1 230 kV Line
14) Julian Hinds-Eagle Mountain 230 kV

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

1) Devers 500 kV
2) Mirage 230 kV
3) Vincent 230 kV
4) San Onofre 230 kV
5) Sylmar 230 kV
6) Lugo 500 kV

I. *San Diego Area*

The most limiting contingency in the San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the new Palomar Combined-Cycle Power plant (542 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. Therefore the 2,620 MW (includes 186 MW of QF generation) of capacity required within this area is predicated on having sufficient generation in the San Diego Area to reduce Path 44 to its non-simultaneous rating of 2500 MW within 30 minutes.

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

The boundaries for the San Diego Area can be defined by the following sub-stations:

1) Miguel 230 kV
2) San Luis Rey 230 kV
3) Talega 230 kV

J. *Zonal Capacity Requirements*

The ISO performed a preliminary assessment of the Zonal Capacity needs and compared these needs to the aggregate amount of capacity already required within the zone due to proposed local area requirements within that zone. The additional requirement for 2006 in NP15, NP15+ZP26 and SP26 appears to be minimal, and is expected to be covered by overall resource procurement requirements.

VII. Next Steps and Future Annual Technical Analyses

The CAISO will transmit this final Local Capacity Technical Analysis to the CPUC, including the assigned Administrative Law Judge, and serve it electronically on the R.04-04-003 service list.

The CAISO believes that the information contained in this report can be used to geographically define each Local Capacity Area, and to assign specific local capacity obligations to LSEs that serve load within these geographic boundaries. The CAISO anticipates that the CPUC will establish such an allocation mechanism for CPUC jurisdictional entities through the CPUC's upcoming orders on Resource Adequacy.

The CAISO recognizes that additional generation, new transmission, or special protection schemes on existing facilities may impact the LCR requirement in certain Local Capacity Areas. While it is not envisioned that such projects, not already accounted for in this study, would be in-service before the 2006 summer peak period, the CAISO will support and work closely with all LSEs, TOs and other market participants in order to assure that new transmission projects, special protection schemes (where applicable and feasible), new generation as well as demand side management projects are reflected in the annual LCR technical analysis for the period when such projects are implemented.

PF bus #	PF bus name	kV	PF Unit #	Resource ID	Resource Name	LCR Area Name	Area #	LCR Sub-Area Name
31150	FAIRHAVN	13.8	1	FAIRHV_6_UNIT	FAIRHAVEN POWER CO.	Humboldt	1	
31152	PAC.LUMB	13.8	1	PACLUM_6_UNIT	PACIFIC LUMBER (HUMBOLDT)	Humboldt	1	
31152	PAC.LUMB	13.8	2	PACLUM_6_UNIT	PACIFIC LUMBER (HUMBOLDT)	Humboldt	1	
31154	HUMBOLDT	13.2	1	HUMBPP_6_MOBILES	Humboldt Mobile unit 3	Humboldt	1	
31154	HUMBOLDT	13.2	2	HUMBPP_6_MOBILES	Humboldt Mobile unit 2	Humboldt	1	
31156	ULTRAPWR	12.5	1	ULTPBL_6_UNIT 1	ULTRAPOWER (BLUE LAKE)	Humboldt	1	
31158	LP SAMOA	12.5	1	LAPAC_6_UNIT	LOUISIANA PACIFIC SAMOA	Humboldt	1	
31166	KEKAWAK	9.1	1	KEKAWK_6_UNIT	STS HYDROPOWER LTD. (KEKAWAK	Humboldt	1	
31170	HMBOLDT1	13.8	1	HUMBPP_7_UNIT 1	Humboldt Bay Unit 1	Humboldt	1	
31172	HMBOLDT2	13.8	1	HUMBPP_7_UNIT 2	HUMBOLDT BAY UNIT 2	Humboldt	1	
31400	SANTA FE	13.8	1	SANTFG_7_UNITS	GEYSERS POWER COMPANY, LLC. (	NCNB	2	Lakeville
31400	SANTA FE	13.8	2	SANTFG_7_UNITS	GEYSERS POWER COMPANY, LLC. (	NCNB	2	Lakeville
31402	BEAR CAN	13.8	1	BEARCN_2_UNIT 1	CALPINE GEYSERS CO. L. P. (KW#1)	NCNB	2	Fulton
31402	BEAR CAN	13.8	2	BEARCN_2_UNIT 2	CALPINE GEYSERS CO. L. P. (KW#2)	NCNB	2	Fulton
31404	WEST FOR	13.8	1	WDFRDF_2_UNITS	CALPINE GEYSERS CO. L. P. (West F	NCNB	2	Fulton
31404	WEST FOR	13.8	2	WDFRDF_2_UNITS	CALPINE GEYSERS CO. L. P. (West F	NCNB	2	Fulton
31406	GEYSR5-6	13.8	1	GYS5X6_7_UNIT 5	Geysers Unit 5	NCNB	2	Eagle Rock
31406	GEYSR5-6	13.8	2	GYS5X6_7_UNIT 6	Geysers Unit 6	NCNB	2	Eagle Rock
31408	GEYSER78	13.8	1	GYS7X8_7_UNIT 7	Geysers Unit 7	NCNB	2	Eagle Rock
31408	GEYSER78	13.8	2	GYS7X8_7_UNIT 8	Geysers Unit 8	NCNB	2	Eagle Rock
31412	GEYSER11	13.8	1	GEYS11_7_UNIT11	GEYSERS UNIT 11 (HEALDSBURG)	NCNB	2	Eagle Rock
31414	GEYSER12	13.8	1	GEYS12_7_UNIT12	GEYSERS UNIT 12 (HEALDSBURG)	NCNB	2	Fulton
31416	GEYSER13	13.8	1	GEYS13_7_UNIT13	GEYSERS UNIT 13 (HEALDSBURG)	NCNB	2	Lakeville
31418	GEYSER14	13.8	1	GEYS14_7_UNIT14	GEYSERS UNIT 14 (HEALDSBURG)	NCNB	2	Fulton
31420	GEYSER16	13.8	1	GEYS16_7_UNIT16	GEYSERS UNIT 16 (HEALDSBURG)	NCNB	2	Fulton
31422	GEYSER17	13.8	1	GEYS17_7_UNIT17	GEYSERS UNIT 17 (HEALDSBURG)	NCNB	2	Fulton
31424	GEYSER18	13.8	1	GEYS18_7_UNIT18	GEYSERS UNIT 18 (HEALDSBURG)	NCNB	2	Lakeville
31426	GEYSER20	13.8	1	GEYS20_7_UNIT20	GEYSERS UNIT 20 (HEALDSBURG)	NCNB	2	Lakeville
31430	SMUDGEO1	13.8	1	SMUDGO_7_UNIT 1	SONOMA POWER PLANT	NCNB	2	Lakeville
31433	POTTRVLY	2.4	1	POTTER_6_UNITS	Potter Valley	NCNB	2	Eagle Rock
31433	POTTRVLY	2.4	3	POTTER_6_UNITS	Potter Valley	NCNB	2	Eagle Rock
31433	POTTRVLY	2.4	4	POTTER_6_UNITS	Potter Valley	NCNB	2	Eagle Rock
31435	GEO.ENGY	9.1	1	ADLIN_1_UNIT 1	GEOTHERMAL ENERGY PARTNERS	NCNB	2	Eagle Rock
31435	GEO.ENGY	9.1	2	ADLIN_1_UNIT 2	GEOTHERMAL ENERGY PARTNERS	NCNB	2	Eagle Rock
31436	INDIAN V	9.1	1	INDVLY_1_UNITS	INDIAN VALLEY HYDRO	NCNB	2	Eagle Rock
31446	SONMA LF	9.1	1	SNMALF_6_UNITS	Sonoma County Landfill	NCNB	2	Fulton
32700	MONTICLO	9.1	1	MONTPH_7_UNIT 1	MONTICELLO Unit 1	NCNB	2	Fulton
32700	MONTICLO	9.1	2	MONTPH_7_UNIT 2	MONTICELLO Unit 2	NCNB	2	Fulton
32700	MONTICLO	9.1	3	MONTPH_7_UNIT 3	MONTICELLO Unit 3	NCNB	2	Fulton
38106	NCPA1GY1	13.8	1	NCPA_7_GP1UN1	NCPA GEO PLANT 1 UNIT 1	NCNB	2	Lakeville
38108	NCPA1GY2	13.8	1	NCPA_7_GP1UN2	NCPA GEO PLANT 1 UNIT 2	NCNB	2	Lakeville
38110	NCPA2GY1	13.8	1	NCPA_7_GP2UN3	NCPA GEO PLANT 2 UNIT 3	NCNB	2	Fulton
38112	NCPA2GY2	13.8	1	NCPA_7_GP2UN4	NCPA GEO PLANT 2 UNIT 4	NCNB	2	Fulton
31784	BELDEN	13.8	1	BELDEN_7_UNIT 1	BELDEN HYDRO	Sierra	3	
31786	ROCK CK1	13.8	1	RCKCRK_7_UNIT 1	ROCK CREEK HYDRO UNIT 1	Sierra	3	
31788	ROCK CK2	13.8	1	RCKCRK_7_UNIT 2	ROCK CREEK HYDRO UNIT 2	Sierra	3	
31790	POE 1	13.8	1	POEPH_7_UNIT 1	POE HYDRO UNIT 1	Sierra	3	
31792	POE 2	13.8	1	POEPH_7_UNIT 2	POE HYDRO UNIT 2	Sierra	3	
31794	WOODLEAF	13.8	1	WDLEAF_7_UNIT 1	WOODLEAF HYDRO	Sierra	3	
31812	CRESTA	11.5	1	CRESTA_7_UNIT 1	CRESTA UNIT #1	Sierra	3	
31812	CRESTA	11.5	2	CRESTA_7_UNIT 2	CRESTA UNIT #2	Sierra	3	
31814	FORBSTWN	11.5	1	FORBST_7_UNIT 1	FORBESTOWN HYDRO	Sierra	3	
31820	BCKS CRK	11	1	BUCKCK_7_PL1X2	BUCKS CREEK AGGREGATE	Sierra	3	
31820	BCKS CRK	11	2	BUCKCK_7_PL1X2	BUCKS CREEK AGGREGATE	Sierra	3	
31832	SLY.CR.	9.1	1	SLYCRK_1_UNIT 1	SLY CREEK HYDRO	Sierra	3	
31834	KELLYRDG	9.1	1	KELYRG_6_UNIT	KELLY RIDGE HYDRO	Sierra	3	
31862	DEADWOOD	9.1	1	DEADCK_1_DEADWD	YUBA COUNTY WATER (DEADWOOD	Sierra	3	
31888	OROVLLE	9.1	1	OROVIL_6_UNIT	OROVILLE COGEN	Sierra	3	
31890	PO POWER	9.1	1	PACORO_6_UNIT	OGDEN POWER PACIFIC,INC. (OROV	Sierra	3	
31890	PO POWER	9.1	2	PACORO_6_UNIT	OGDEN POWER PACIFIC,INC. (OROV	Sierra	3	
32156	WOODLAND	9.1	1	BIOMAS_1_UNIT 1	WOODLAND BIOMASS	Sierra	3	
32166	UC DAVIS	9.1	1	UCDAVS_1_UNIT	UC DAVIS CAMPUS GENERATION	Sierra	3	
32450	COLGATE1	13.8	1	COLGAT_7_UNIT 1	COLGATE HYDRO UNIT 1	Sierra	3	
32451	FREC	13.8	1	BOGUE_1_UNITA1	Feather River Energy Center	Sierra	3	
32452	COLGATE2	13.8	1	COLGAT_7_UNIT 2	COLGATE HYDRO UNIT 2	Sierra	3	

PF bus #	PF bus name	kV	PF Unit #	Resource ID	Resource Name	LCR Area Name	Area #	LCR Sub-Area Name
32454	DRUM 5	13.8	1	DRUM_7_UNIT 5	DRUM PH 2 UNIT 5	Sierra	3	
32456	MIDLFORK	13.8	1	MIDFRK_7_UNIT 1	MIDDLE FORK UNIT 1	Sierra	3	
32456	MIDLFORK	13.8	2	MIDFRK_7_UNIT 2	MIDDLE FORK UNIT 2	Sierra	3	
32458	RALSTON	13.8	1	RALSTN_7_UNIT 1	RALSTON UNIT 1	Sierra	3	
32460	NEWCSTLE	13.2	1	NWCSTL_7_UNIT 1	NEWCASTLE HYDRO	Sierra	3	
32462	CHI.PARK	11.5	1	CHICPK_7_UNIT 1	CHICAGO PARK 1, BEAR RIVER CA	Sierra	3	
32464	DTCHFLT1	11	1	DUTCH1_7_UNIT 1	DUTCH FLAT 1 PH	Sierra	3	
32466	NARROWS1	9.1	1	NAROW1_2_UNIT	NARROWS PH 1 UNIT	Sierra	3	
32468	NARROWS2	9.1	1	NAROW2_2_UNIT	NARROWS PH 2 UNIT	Sierra	3	
32470	CMP.FARW	9.1	1	CAMPFW_7_FARWST	CAMP FAR WEST HYDRO	Sierra	3	
32472	SPAULDG	9.1	1	SPAULD_6_UNIT 1	SPAULDING HYDRO PH 1 UNIT	Sierra	3	
32472	SPAULDG	9.1	2	SPAULD_6_UNIT 2	SPAULDING HYDRO PH 2 UNIT	Sierra	3	
32472	SPAULDG	9.1	3	SPAULD_6_UNIT 3	SPAULDING HYDRO PH 3 UNIT	Sierra	3	
32474	DEER CRK	9.1	1	DEERCR_6_UNIT 1	DEER CREEK	Sierra	3	
32476	ROLLINSF	9.1	1	ROLLIN_6_UNIT	ROLLINS HYDRO	Sierra	3	
32478	HALSEY F	9.1	1	HALSEY_6_UNIT	HALSEY HYDRO	Sierra	3	
32480	BOWMAN	9.1	1	BOWMN_6_UNIT	NEVADA POWER AUTHORITY	Sierra	3	
32484	OXBOW F	9.1	1	OXBOW_6_DRUM	OXBOW HYDRO	Sierra	3	
32486	HELLHOLE	9.1	1	HELLHL_6_UNIT	HELL HOLE HYDRO	Sierra	3	
32488	HAYPRES+	9.1	1	HAYPRS_6_UNIT 1	HAYPRESS HYDROELECTRIC,INC. (I	Sierra	3	
32488	HAYPRES+	9.1	2	HAYPRS_6_UNIT 2	HAYPRESS HYDROELECTRIC,INC. (I	Sierra	3	
32490	GRNLEAF1	13.8	1	GRNLF1_1_UNITS	GREENLEAF #1 COGEN AGGREGAT	Sierra	3	
32490	GRNLEAF1	13.8	2	GRNLF1_1_UNITS	GREENLEAF #1 COGEN AGGREGAT	Sierra	3	
32492	GRNLEAF2	13.8	1	GRNLF2_1_UNIT	GREENLEAF II COGEN	Sierra	3	
32494	YUBA CTY	9.1	1	YUBACT_1_SUNSWT	YUBA CITY COGEN	Sierra	3	
32496	YCEC	13.8	1	GRNLF1_1_UNIT 1	Yuba City Energy Center	Sierra	3	
32498	SPILINCF	12.5	1	SPI LI_2_UNIT 1	SIERRA PACIFIC IND. (LINCOLN)	Sierra	3	
32500	ULTR RCK	9.1	1	ULTRCK_2_UNIT	Rio Bravo Rocklin	Sierra	3	
32502	DTCHFLT2	6.9	1	DUTCH2_7_UNIT 1	DUTCH FLAT 2 PH	Sierra	3	
32504	DRUM 1-2	6.6	1	DRUM_7_UNIT 1	DRUM PH 1 UNIT 1	Sierra	3	
32504	DRUM 1-2	6.6	2	DRUM_7_UNIT 2	DRUM PH 1 UNIT 2	Sierra	3	
32506	DRUM 3-4	6.6	1	DRUM_7_UNIT 3	Drum PH 1 Unit 3	Sierra	3	
32506	DRUM 3-4	6.6	2	DRUM_7_UNIT 4	Drum PH 1 Unit 4	Sierra	3	
32508	FRNCH MD	4.2	1	FMEADO_7_UNIT	FRENCH MEADOWS HYDRO	Sierra	3	
32510	CHILIBAR	4.2	1	PLACVL_1_CHILIB	Chili Bar	Sierra	3	
32512	WISE	12	1	WISE_1_UNIT 1	Wise Hydro Unit 1	Sierra	3	
32513	ELDRADO1	21.6	1	ELDORO_7_UNIT 1	El Dorado Irrigation Dist. Unit 1	Sierra	3	
32514	ELDRADO2	21.6	1	ELDORO_7_UNIT 2	El Dorado Irrigation Dist. Unit 2	Sierra	3	
33805	GWFTRCY1	13.8	1	SCHLTE_1_UNITA1	Tracy Unit 1 Peaking Project	Stockton	4	TeslaBellota
33807	GWFTRCY2	13.8	1	SCHLTE_1_UNITA2	Tracy Unit 2 Peaking Project	Stockton	4	TeslaBellota
33814	CPC STCN	12.5	1	STOKCG_1_UNIT 1	STOCKTON COGEN CO.	Stockton	4	TeslaBellota
33850	CAMANCHE	4.2	1	CAMCHE_1_UNIT 1	Camanche 1	Stockton	4	TeslaBellota
33850	CAMANCHE	4.2	2	CAMCHE_1_UNIT 2	Camanche 2	Stockton	4	TeslaBellota
33850	CAMANCHE	4.2	3	CAMCHE_1_UNIT 3	Camanche 3	Stockton	4	TeslaBellota
33917	FBERBORD	115	1	SPIFBD_1_PL1X2	SIERRA PACIFIC IND. (SONORA)	Stockton	4	TeslaBellota
34050	CH.STN.	13.8	1	ULTPCH_1_UNIT 1	OGDEN POWER PACIFIC (CHINESE	Stockton	4	TeslaBellota
34056	STNSLSRP	13.8	1	STNRES_1_UNIT	STANISLAUS WASTE ENERGY CO.	Stockton	4	TeslaBellota
34058	DONNELLS	13.8	1	DONNLS_7_UNIT	DONNELLS HYDRO	Stockton	4	TeslaBellota
34060	SANDBAR	13.8	1	SNDBAR_7_UNIT 1	TRI DAM AUTHORITY	Stockton	4	TeslaBellota
34062	STANISLS	13.8	1	STANIS_7_UNIT 1	STANISLAUS HYDRO	Stockton	4	TeslaBellota
34074	BEARDSLY	6.9	1	BEARDS_7_UNIT 1	BEARDSLEY HYDRO	Stockton	4	TeslaBellota
34076	TULLOCH	6.9	1	TULLCK_7_UNITS	TULLOCH HYDRO AGGREGATE	Stockton	4	TeslaBellota
34076	TULLOCH	6.9	2	TULLCK_7_UNITS	TULLOCH HYDRO AGGREGATE	Stockton	4	TeslaBellota
34078	SPRNG GP	6	1	SPRGAP_1_UNIT 1	SPRING GAP HYDRO	Stockton	4	TeslaBellota
38120	LODI25CT	9.11	1	LODI25_2_UNIT 1	Lodi GT	Stockton	4	Lockeford
30000	PTSB 7	20	1	PITTSP_7_UNIT 7	PITTSBURG UNIT 7	Bay Area	5	Pittsburg
32173	LAMBGT1	13.8	1	LMBEPK_2_UNITA1	Lambie Energy Center, Unit #1	Bay Area	5	
32174	GOOSEHGT	13.8	2	LMBEPK_2_UNITA2	Creed Energy Center, Unit #1	Bay Area	5	
32175	CREEDGT1	13.8	3	LMBEPK_2_UNITA3	Goose Haven Energy Center, Unit #1	Bay Area	5	
32740	HILLSIDE	115	1	GRZZLY_1_BERKLY	PE - BERKELEY, INC.	Bay Area	5	Pittsburg
32900	CRCKTCOG	18	1	CROKET_7_UNIT	CROCKETT COGEN	Bay Area	5	Pittsburg
32901	OAKLND 1	13.8	1	OAK C_7_UNIT 1	OAKLAND STATION C GT UNIT 1	Bay Area	5	Oakland
32902	OAKLND 2	13.8	1	OAK C_7_UNIT 2	OAKLAND STATION C GT UNIT 2	Bay Area	5	Oakland
32903	OAKLND 3	13.8	1	OAK C_7_UNIT 3	OAKLAND STATION C GT UNIT 3	Bay Area	5	Oakland
32910	UNOCAL	12	1	UNOCAL_1_UNITS	TOSCO (RODEO PLANT)	Bay Area	5	Pittsburg

PF bus #	PF bus name	kV	PF Unit #	Resource ID	Resource Name	LCR Area Name	Area #	LCR Sub-Area Name
32910	UNOCAL	12	2	UNOCAL_1_UNITS	TOSCO (RODEO PLANT)	Bay Area	5	Pittsburg
32910	UNOCAL	12	3	UNOCAL_1_UNITS	TOSCO (RODEO PLANT)	Bay Area	5	Pittsburg
32920	UNION CH	9.11	1	UNCHEM_1_UNIT	CONTRA COSTA CARBON PLANT	Bay Area	5	Pittsburg
32921	CHEVGEN1	13.8	1	STOILS_1_UNITS	CHEVRON RICHMOND REFINERY	Bay Area	5	Pittsburg
32922	CHEVGEN2	13.8	1	STOILS_1_UNITS	CHEVRON RICHMOND REFINERY	Bay Area	5	Pittsburg
33105	PTSB 5	18	1	PITTSP_7_UNIT 5	PITTSBURG UNIT 5	Bay Area	5	Pittsburg
33106	PTSB 6	18	1	PITTSP_7_UNIT 6	PITTSBURG UNIT 6	Bay Area	5	Pittsburg
33107	DEC STG1	24	1	DELTA_2_STG	DELTA ENERGY CENTER STG UNIT	Bay Area	5	Pittsburg
33108	DEC CTG1	18	1	DELTA_2_CTG1	DELTA ENERGY CENTER CTG UNIT	Bay Area	5	Pittsburg
33109	DEC CTG2	18	1	DELTA_2_CTG2	DELTA ENERGY CENTER CTG UNIT	Bay Area	5	Pittsburg
33110	DEC CTG3	18	1	DELTA_2_CTG3	DELTA ENERGY CENTER CTG UNIT	Bay Area	5	Pittsburg
33111	LMECCT2	18	1	LMEC_1_CTG2	LOS MEDANOS CTG UNIT 2	Bay Area	5	Pittsburg
33112	LMECCT1	18	1	LMEC_1_CTG1	LOS MEDANOS CTG UNIT 1	Bay Area	5	Pittsburg
33113	LMECST1	18	1	LMEC_1_STG	LOS MEDANOS STG UNIT	Bay Area	5	Pittsburg
33116	C.COS 6	18	1	COCOPP_7_UNIT 6	CONTRA COSTA UNIT 6	Bay Area	5	
33117	C.COS 7	18	1	COCOPP_7_UNIT 7	CONTRA COSTA UNIT 7	Bay Area	5	
33131	GWF #1	9.11	1	GWFPW1_6_UNIT	GWF POWER SYSTEMS INC. #1	Bay Area	5	
33132	GWF #2	13.8	1	GWFPW2_1_UNIT 1	GWF POWER SYSTEMS INC. #2	Bay Area	5	Pittsburg
33133	GWF #3	13.8	1	GWFPW3_1_UNIT 1	GWF POWER SYSTEMS INC. #3	Bay Area	5	
33134	GWF #4	13.8	1	GWFPW4_6_UNIT 1	GWF POWER SYSTEMS INC. #4	Bay Area	5	
33135	GWF #5	13.8	1	GWFPW5_6_UNIT 1	GWF POWER SYSTEMS INC. #5	Bay Area	5	Pittsburg
33136	CCCSD	12.47	1	IMHOFF_1_UNIT 1	CONTRA COSTA SANITATION DISTR	Bay Area	5	Pittsburg
33139	STAUFER	9.11	1	STAUFF_1_UNIT	RHODIA INC. (RHONE-POULENC)	Bay Area	5	Pittsburg
33141	SHELL 1	12.47	1	SHELRF_1_UNITS	SHELL OIL REFINERY AGGREGATE	Bay Area	5	Pittsburg
33142	SHELL 2	12.47	1	SHELRF_1_UNITS	SHELL OIL REFINERY AGGREGATE	Bay Area	5	Pittsburg
33143	SHELL 3	12.47	1	SHELRF_1_UNITS	SHELL OIL REFINERY AGGREGATE	Bay Area	5	Pittsburg
33145	CROWN.Z.	13.8	1	GAYCRZ_1_UNIT 1	GAYLORD	Bay Area	5	
33145	CROWN.Z.	13.8	2	GAYCRZ_1_UNIT 1	GAYLORD	Bay Area	5	
33151	FOSTER W	12.47	1	TIDWTR_2_UNITS	MARTINEZ COGEN LIMITED PARTNE	Bay Area	5	Pittsburg
33151	FOSTER W	12.47	2	TIDWTR_2_UNITS	MARTINEZ COGEN LIMITED PARTNE	Bay Area	5	Pittsburg
33151	FOSTER W	12.47	3	TIDWTR_2_UNITS	MARTINEZ COGEN LIMITED PARTNE	Bay Area	5	Pittsburg
33161	DOWCHEM1	13.8	1	DOWCHM_1_UNITS	Calpine Pittsburg Power Plant 1	Bay Area	5	Pittsburg
33162	DOWCHEM2	13.8	1	DOWCHM_1_UNITS	Calpine Pittsburg Power Plant 2	Bay Area	5	Pittsburg
33163	DOWCHEM3	13.8	1	DOWCHM_1_UNITS	Calpine Pittsburg Power Plant 3	Bay Area	5	Pittsburg
33170	WINDMSTR	9.11	1	WNDMAS_2_UNIT 1	BUENA VISTA ENERGY,LLC	Bay Area	5	
33178	RVEC_GEN	13.8	1	RVRVEW_1_UNITA1	Riverview Energy Center (GP Antioch)	Bay Area	5	
33252	POTRERO3	20	1	POTRPP_7_UNIT 3	POTRERO UNIT 3	Bay Area	5	San Francisco
33253	POTRERO4	13.8	1	POTRPP_7_UNIT 4	POTRERO UNIT 4	Bay Area	5	San Francisco
33254	POTRERO5	13.8	1	POTRPP_7_UNIT 5	POTRERO UNIT 5	Bay Area	5	San Francisco
33255	POTRERO6	13.8	1	POTRPP_7_UNIT 6	POTRERO UNIT 6	Bay Area	5	San Francisco
33270	HNTRS P4	18	1	HUNTER_7_UNIT 4	HUNTERS POINT UNIT 4	Bay Area	5	San Francisco
33271	HNTRS P1	12	1	HUNTER_7_UNIT 1	HUNTERS POINT UNIT 1	Bay Area	5	San Francisco
33463	CARDINAL	12.47	1	CARDCG_1_UNITS	CARDINAL COGEN	Bay Area	5	
33463	CARDINAL	12.47	2	CARDCG_1_UNITS	CARDINAL COGEN	Bay Area	5	
33466	UNTED CO	9.11	1	UNTDQF_7_UNITS	UNITED AIRLINES (COGEN)	Bay Area	5	
33468	SRI INTL	9.11	1	SRINTL_6_UNIT	SRI INTERNATIONAL	Bay Area	5	
35637	IBM-CTLE	115	1	IBMCTL_1_UNIT 1	IBM Cottle	Bay Area	5	
35850	GLRY COG	13.8	1	GILROY_1_CT1	GILROY COGEN - UNIT 1	Bay Area	5	San Jose
35850	GLRY COG	13.8	2	GILROY_1_CT1	GILROY COGEN - UNIT 1	Bay Area	5	San Jose
35851	GROYPKR1	13.8	1	GILRPP_1_PL1X2	Gilroy Peaker - Unit 1	Bay Area	5	San Jose
35852	GROYPKR2	13.8	1	GILRPP_1_PL1X2	Gilroy Peaker - Unit 2	Bay Area	5	San Jose
35853	GROYPKR3	13.8	1	GILRPP_1_PL3X4	Gilroy Peaker - Unit 3	Bay Area	5	San Jose
35854	LECEFGT1	13.8	1	LECEF_1_UNITS	Los Esteros Critical Energy Center 1	Bay Area	5	
35855	LECEFGT2	13.8	1	LECEF_1_UNITS	Los Esteros Critical Energy Center 2	Bay Area	5	
35856	LECEFGT3	13.8	1	LECEF_1_UNITS	Los Esteros Critical Energy Center 3	Bay Area	5	
35857	LECEFGT4	13.8	1	LECEF_1_UNITS	Los Esteros Critical Energy Center 4	Bay Area	5	
35860	OLS-AGNE	9.11	1	CALPIN_1_AGNEW	GATX/CALPINE COGEN-AGNEWS IN	Bay Area	5	
35861	SJ-SCL W	9.11	1			Bay Area	5	
35863	CATALYST	9.11	1	MARKHM_1_CATLST	SAN JOSE COGEN	Bay Area	5	
35881	MEC CTG1	18	1	METEC_2_PL1X3	Metcalf Energy Center	Bay Area	5	
35882	MEC CTG2	18	1	METEC_2_PL1X3	Metcalf Energy Center	Bay Area	5	
35883	MEC STG1	18	1	METEC_2_PL1X3	Metcalf Energy Center	Bay Area	5	
36854	CSC COG.	12	1	CSCCOG_1_UNIT 1	SVP COGEN	Bay Area	5	
36854	CSC COG.	12	2	CSCCOG_1_UNIT 1	SVP COGEN	Bay Area	5	
36856	CSC_CCA	13.8	1	CONTAN_1_UNIT	SMURFIT STONE (CONTAINER CORI	Bay Area	5	

PF bus #	PF bus name	kV	PF Unit #	Resource ID	Resource Name	LCR Area Name	Area #	LCR Sub-Area Name
36858	CSC_GNR1	13.8	1	CSCGNR_1_UNIT 1	GIANERA PEAKER UNIT 1	Bay Area	5	
36863	DVRPPCT1	13.8	1	DUANE_1_PL1X3	DVR UNITS	Bay Area	5	
36864	DVRPPCT2	13.8	1	DUANE_1_PL1X3	DVR UNITS	Bay Area	5	
36865	DVRPPSTA	13.8	1	DUANE_1_PL1X3	DVR UNITS	Bay Area	5	
36895	CSC_GNR2	13.8	2	CSCGNR_1_UNIT 2	GIANERA PEAKER UNIT 2	Bay Area	5	
38118	ALMDACT1	13.8	1	ALMEGT_1_UNIT 1	ALAMEDA GT UNIT 1	Bay Area	5	Oakland
38119	ALMDACT2	13.8	1	ALMEGT_1_UNIT 2	ALAMEDA GT UNIT 2	Bay Area	5	Oakland
34142	WHD_PAN2	13.8	1	PNOCHE_1_UNITB1	Wellhead Power - Panoche	Fresno	6	Herndon, Wilson
34179	MADERA_G	13.8	1	CAPMAD_1_UNIT 1	CAPCO MADERA Power Plant	Fresno	6	Herndon, Wilson
34186	DG_PAN1	13.8	1	PNOCHE_1_UNITA1	CalPeak Power - Panoche LLC	Fresno	6	Herndon, Wilson
34301	CHOWCOGN	13.8	1	CHWCHL_1_UNIT	CHOW 2 PEAKER PLANT	Fresno	6	Herndon, Wilson
34306	EXCHQUER	13.8	1	EXCHEC_7_UNIT 1	EXCHEQUER HYDRO	Fresno	6	Wilson, Merced
34308	KERCKHOF	13.8	1	KERKH2_7_UNIT 1	KERKHOFF PH 2 UNIT #1	Fresno	6	Herndon, Wilson
34320	MCSWAIN	9.11	1	MCSWAN_6_UNITS	MC SWAIN HYDRO	Fresno	6	Wilson, Merced
34322	MERCEDFL	9.11	1	MERCFL_6_UNIT	MERCED FALLS	Fresno	6	Wilson, Merced
34332	JRWCOGEN	9.11	1	JRWOOD_1_UNIT 1	SAN JOAQUIN POWER COMPANY	Fresno	6	Wilson, Merced
34334	BIO PWR	9.11	1	MENBIO_6_UNIT	MENDOTA BIOMASS POWER	Fresno	6	Herndon, Wilson
34342	INT.TURB	9.11	1	INTTRB_6_UNIT	Intl Wind Turb Research (Dinosaur Poi	Fresno	6	Wilson
34344	KERCKHOF	6.6	1	KERKH1_7_UNIT 1	Kerchoff 1	Fresno	6	Herndon, Wilson
34344	KERCKHOF	6.6	2	KERKH1_7_UNIT 2	Kerchoff 2	Fresno	6	Herndon, Wilson
34344	KERCKHOF	6.6	3	KERKH1_7_UNIT 3	Kerchoff 3	Fresno	6	Herndon, Wilson
34431	GWF_HEP1	13.8	1	GWFPWR_1_UNITS	HEP PEAKER PLANT AGGREGATE	Fresno	6	Herndon, Wilson
34433	GWF_HEP2	13.8	1	GWFPWR_1_UNITS	HEP PEAKER PLANT AGGREGATE	Fresno	6	Herndon, Wilson
34539	GWF_GT1	13.8	1	HENRTA_6_UNITA1	GWF HENRIETTA PEAKER PLANT UI	Fresno	6	Wilson, Henrietta
34541	GWF_GT2	13.8	1	HENRTA_6_UNITA2	GWF HENRIETTA PEAKER PLANT UI	Fresno	6	Wilson, Henrietta
34553	WHD_GAT2	13.8	1	GATES_6_UNIT	Wellhead Power-Gates	Fresno	6	Herndon, Wilson
34600	HELMS	18	1	HELMPG_7_UNIT 1	HELMS PUMP-GEN UNIT 1	Fresno	6	Wilson, McCall
34602	HELMS	18	2	HELMPG_7_UNIT 2	HELMS PUMP-GEN UNIT 2	Fresno	6	Wilson, McCall
34604	HELMS	18	3	HELMPG_7_UNIT 3	HELMS PUMP-GEN UNIT 3	Fresno	6	Wilson, McCall
34608	AGRICO	13.8	2	AGRICO_6_UNIT 3	Fresno Peaker of Wellhead	Fresno	6	Herndon, Wilson
34608	AGRICO	13.8	3			Fresno	6	Herndon, Wilson
34608	AGRICO	13.8	4			Fresno	6	Herndon, Wilson
34610	HAAS	13.8	1	HAASPH_7_UNIT 1	HAAS PH UNIT 1	Fresno	6	Herndon, Wilson
34610	HAAS	13.8	2	HAASPH_7_UNIT 2	HAAS PH UNIT 2	Fresno	6	Herndon, Wilson
34612	BLCH	13.8	1	BALCHS_7_UNIT 2	BALCH 2 PH UNIT 2	Fresno	6	Herndon, Wilson
34614	BLCH	13.8	1	BALCHS_7_UNIT 3	BALCH 2 PH UNIT 3	Fresno	6	Herndon, Wilson
34616	KINGSRIV	13.8	1	KINGRV_7_UNIT 1	KINGS RIVER HYDRO UNIT 1	Fresno	6	Herndon, Wilson
34624	BALCH	13.2	1	BALCHS_7_UNIT 1	BALCH 1 PH UNIT 1	Fresno	6	Herndon, Wilson
34631	SJ2GEN	9.11	1	CRNEVL_6_SJQN 2	SAN JOAQUIN 2	Fresno	6	Wilson, McCall
34633	SJ3GEN	9.11	1	CRNEVL_6_SJQN 3	SAN JOAQUIN 3	Fresno	6	Wilson, McCall
34636	FRIANTDM	9.11	1	FRIANT_6_UNITS	FRIANT DAM	Fresno	6	Wilson, McCall
34640	ULTR.PWR	9.11	1	ULTPFR_1_UNIT 1	RIO BRAVO FRESNO	Fresno	6	Herndon, Wilson
34642	KINGSBUR	9.11	1	KINGCO_1_KINGBR	PE - KES KINGSBURG,LLC	Fresno	6	Herndon, Wilson
34646	SANGERCO	9.11	1	SGREGY_6_SANGER	DYNAMIS COGEN	Fresno	6	Herndon, Wilson, McCall
34648	DINUBA E	13.8	1	DINUBA_6_UNIT	DINUBA GENERATION PROJECT	Fresno	6	Herndon, Wilson, McCall
34650	GWF-PWR.	9.11	1	GWFPWR_6_UNIT	HANFORD L.P.	Fresno	6	Wilson, Henrietta
34652	CHV.COAL	9.11	1	CHEVCO_6_UNIT 1	CHEVRON USA (COALINGA)	Fresno	6	Herndon, Wilson
34652	CHV.COAL	9.11	2	CHEVCO_6_UNIT 2	AERA ENERGY LLC. (COALINGA)	Fresno	6	Herndon, Wilson
34654	COLNEAGN	9.11	1	COLGA1_6_SHELLW	COALINGA COGENERATION COMPA	Fresno	6	Herndon, Wilson
34658	WISHON	2.3	1	WISHON_6_UNITS	Wishon 1	Fresno	6	Wilson, McCall
34658	WISHON	2.3	2	WISHON_6_UNITS	Wishon 2	Fresno	6	Wilson, McCall
34658	WISHON	2.3	3	WISHON_6_UNITS	Wishon 3	Fresno	6	Wilson, McCall
34658	WISHON	2.3	4	WISHON_6_UNITS	Wishon 4	Fresno	6	Wilson, McCall
34671	KRCDPCT1	13.8	1	new unit	Kings River Conservation District (Mala	Fresno	6	Herndon, Wilson
34672	KRCDPCT2	13.8	1	new unit	Kings River Conservation District (Mala	Fresno	6	Herndon, Wilson
34783	TEXCO_NM	9.11	1	TXNMID_1_UNIT 2	CHEVRON/TEXACO INC(NORTH MID	Kern	7	Kern PP
34783	TEXCO_NM	9.11	2	TXNMID_1_UNIT 3	CHEVRON/TEXACO INC(NORTH MID	Kern	7	Kern PP
35018	KERNCNYN	9.11	1	KRNCNY_6_UNIT	KERN CANYON	Kern	7	Weedpatch
35020	RIOBRAVO	9.11	1	RIOBRV_6_UNIT 1	KERN HYDRO (OLCESE)	Kern	7	Weedpatch
35023	DOUBLE C	9.11	1	DOUBLC_1_UNITS	DOUBLE "C" LIMITED	Kern	7	Kern PP
35024	DEXEL +	9.11	1	DEXZEL_1_UNIT	DAI / OILDALE , INC.	Kern	7	Kern PP
35026	KERNFRNT	9.11	1	KERNFT_1_UNITS	KERN FRONT LIMITED	Kern	7	Kern PP
35027	HISIERRA	9.11	1	SIERRA_1_UNITS	HIGH SIERRA LIMITED	Kern	7	Kern PP
35028	OILDALE	9.11	1	OILDAL_1_UNIT 1	OILDALE ENERGY LLC	Kern	7	Kern PP
35029	BADGERCK	9.11	1	BDGRCK_1_UNITS	BADGER CREEK LIMITED	Kern	7	Kern PP

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35032	CHV-CYMR	9.11	1	CHEVCY_1_UNIT	CHEVRON USA (CYMRIC)	Kern	7	Kern PP
35034	MIDSUN +	9.11	1	MIDSUN_1_UNITA1	Midsun Generating Facility	Kern	7	Kern PP
35035	ULTR PWR	9.11	1	ULTOGL_1_POSO	RIO BRAVO POSO	Kern	7	Kern PP
35036	MT POSO	9.11	1	MTNPOS_1_UNIT	MT.POSO COGENERATION CO.	Kern	7	Kern PP
35037	UNIVRSTY	9.11	1	UNVRSY_1_UNIT 1	BERRY PETROLEUM COGEN 38	Kern	7	Kern PP
35038	CHLKCLF+	9.11	1	CHALK_1_UNIT	CHALK CLIFF LIMITED	Kern	7	Kern PP
35040	KERNRDGE	9.11	1	KERNRG_1_UNITS	AERA ENERGY (SOUTH BELRIDGE)	Kern	7	Kern PP
35044	TX MIDST	9.11	1	MIDSET_1_UNIT 1	MIDSET COGEN. CO.	Kern	7	Kern PP
35046	SEKR	9.11	1	VEDDER_1_SEKERN	TEXACO EXPLORATION & PRODUCT	Kern	7	Kern PP
35048	FRITOLAY	9.11	1	FRITO_1_LAY	FRITO-LAY	Kern	7	Kern PP
35050	SLR-TANN	9.11	1	TANHIL_6_SOLART	BERRY PETROLEUM COGEN 18 AG(	Kern	7	Kern PP
35052	CHEV.USA	9.11	1	CHEVCD_6_UNIT	CHEVRON USA (TAFT/CADET)	Kern	7	Kern PP
35058	PSE-LVOK	9.11	1	LIVOAK_1_UNIT 1	LIVE OAK LIMITED	Kern	7	Kern PP
35060	PSEMCKIT	9.11	1	MKTRCK_1_UNIT 1	MCKITTRICK LIMITED	Kern	7	Kern PP
35062	DISCOVRY	9.11	1	DISCOV_1_CHEVRN	CHEVRON USA (EASTRIDGE)	Kern	7	Kern PP
35064	NAVY 35R	9.11	1	NAVY35_1_UNITS	OCCIDENTAL OF ELK HILLS,INC.	Kern	7	Kern PP
35066	PSE-BEAR	9.11	1	BEARMT_1_UNIT	BEAR MOUNTAIN LIMITED	Kern	7	Kern PP
24001	ALAMT1 G	18	1	ALAMIT_7_UNIT 1	ALAMITOS GEN STA. UNIT 1	LA Basin	8	Western
24002	ALAMT2 G	18	2	ALAMIT_7_UNIT 2	ALAMITOS GEN STA. UNIT 2	LA Basin	8	Western
24003	ALAMT3 G	18	3	ALAMIT_7_UNIT 3	ALAMITOS GEN STA. UNIT 3	LA Basin	8	Western
24004	ALAMT4 G	18	4	ALAMIT_7_UNIT 4	ALAMITOS GEN STA. UNIT 4	LA Basin	8	Western
24005	ALAMT5 G	20	5	ALAMIT_7_UNIT 5	ALAMITOS GEN STA. UNIT 5	LA Basin	8	Western
24011	ARCO 1G	13.8	1	ARCOGN_2_UNITS		LA Basin	8	Western
24012	ARCO 2G	13.8	2	ARCOGN_2_UNITS		LA Basin	8	Western
24013	ARCO 3G	13.8	3	ARCOGN_2_UNITS		LA Basin	8	Western
24014	ARCO 4G	13.8	4	ARCOGN_2_UNITS		LA Basin	8	Western
24018	BRIGEN	13.8	1	BRIGEN_1_UNIT 1	OBRIEN CALIFORNIA COGENERATI(	LA Basin	8	Western
24020	CARBOGEN	13.8	1	HINSON_6_CARBGN	BP WILMINGTON CALCINER	LA Basin	8	Western
24022	CHEVGEN1	13.8	1	CHEVMN_2_UNITS		LA Basin	8	Western
24023	CHEVGEN2	13.8	2	CHEVMN_2_UNITS		LA Basin	8	Western
24026	CIMGEN	13.8	1	CHINO_6_CIMGEN	O.L.S. ENERGY COMPANY -- CHINO	LA Basin	8	Western
24047	ELSEG3 G	18	3	ELSEGN_7_UNIT 3	EL SEGUNDO GEN STA. UNIT 3	LA Basin	8	Western
24048	ELSEG4 G	18	4	ELSEGN_7_UNIT 4	EL SEGUNDO GEN STA. UNIT 4	LA Basin	8	Western
24062	HARBOR G	13.8	1	HARBGN_7_UNIT 1	Harbor Cogen Unit 1	LA Basin	8	Western
24062	HARBOR G	13.8	HP	HARBGN_7_PL2X3	HARBOR COGEN UNITS 2 & 3 AGGR	LA Basin	8	Western
24063	HILLGEN	13.8	1	WALNUT_6_HILLGEN	L.A. COUNTY SANITATION DISTRICT	LA Basin	8	Western
24064	HINSON	66	1	HINSON_6_QF	HINSON QFS	LA Basin	8	Western
24066	HUNT1 G	13.8	1	HNTGBH_7_UNIT 1	HUNTINGTON BEACH GEN STA. UNI	LA Basin	8	Western
24067	HUNT2 G	13.8	2	HNTGBH_7_UNIT 2	HUNTINGTON BEACH GEN STA. UNI	LA Basin	8	Western
24070	ICEGEN	13.8	1	LGHTHP_6_ICEGEN	CARSON COGENERATION COMPAN	LA Basin	8	Western
24073	LA FRESA	66	1			LA Basin	8	Western
24075	LAGUBELL	66	1			LA Basin	8	Western
24094	MOBGEN	13.8	1	MOBGEN_6_UNIT 1	MOBIL OIL CORPORATION	LA Basin	8	Western
24120	PULPGEN	13.8	1	PULPGN_6_UNIT	JEFFERSON SMURFIT CORPORATI(	LA Basin	8	Western
24121	REDON5 G	18	5	REDOND_7_UNIT 5	REDONDO GEN STA. UNIT 5	LA Basin	8	Western
24122	REDON6 G	18	6	REDOND_7_UNIT 6	REDONDO GEN STA. UNIT 6	LA Basin	8	Western
24123	REDON7 G	20	7	REDOND_7_UNIT 7	REDONDO GEN STA. UNIT 7	LA Basin	8	Western
24124	REDON8 G	20	8	REDOND_7_UNIT 8	REDONDO GEN STA. UNIT 8	LA Basin	8	Western
24129	S.ONOFR2	22	2	SONGS_7_UNIT 2	SAN ONOFRE NUCLEAR UNIT 2	LA Basin	8	Western
24130	S.ONOFR3	22	3	SONGS_7_UNIT 3	SAN ONOFRE NUCLEAR UNIT 3	LA Basin	8	Western
24133	SANTIAGO	66	1			LA Basin	8	Western
24139	SERRFGEN	13.8	1	HINSON_6_SERRGN	CITY OF LONG BEACH	LA Basin	8	Western
24161	ALAMT6 G	20	6	ALAMIT_7_UNIT 6	ALAMITOS GEN STA. UNIT 6	LA Basin	8	Western
24163	ARCO 5G	13.8	5	ARCOGN_2_UNITS		LA Basin	8	Western
24164	ARCO 6G	13.8	6	ARCOGN_2_UNITS		LA Basin	8	Western
24167	HUNT3 G	13.8	3	HNTGBH_7_UNIT 3	HUNTINGTON BEACH GEN STA. UNI	LA Basin	8	Western
24168	HUNT4 G	13.8	4	HNTGBH_7_UNIT 4	HUNTINGTON BEACH GEN STA. UNI	LA Basin	8	Western
24197	ELLIS	66	1			LA Basin	8	Western
24203	CENTER S	66	1			LA Basin	8	Western
24211	OLINDA	66	1	OLINDA_2_QF		LA Basin	8	Western
25203	ANAHEIMG	13.8	1	ANAHM_7_CT	ANAHEIM COMBUSTION TURBINE	LA Basin	8	Western
25510	HARBORG4	4.16	LP	HARBGN_7_PL2X3	HARBOR COGEN UNITS 2 & 3 AGGR	LA Basin	8	Western
28005	PASADNA1	13.8	1	GLNARM_7_UNIT 1	GLEN ARM UNIT 1	LA Basin	8	Western
28006	PASADNA2	13.8	1	GLNARM_7_UNIT 2	GLEN ARM UNIT 2	LA Basin	8	Western
28007	BRODWYSC	13.8	1	BRDWAY_7_UNIT 3	BROADWAY UNIT 3	LA Basin	8	Western

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2020	CENTURY	13.8	1			LA Basin	8	Eastern
2021	DREWS	13.8	1			LA Basin	8	Eastern
24024	CHINO	66	1			LA Basin	8	Eastern
24030	DELGEN	13.8	1	MIRLOM_6_DELGEN	CORONA ENERGY PARTNERS LTD.	LA Basin	8	Eastern
24052	MTNVIST3	18	3	ETIWND_7_UNIT 3	ETIWANDA GEN STA. UNIT 3	LA Basin	8	Eastern
24053	MTNVIST4	18	4	ETIWND_7_UNIT 4	ETIWANDA GEN STA. UNIT 4	LA Basin	8	Eastern
24071	INLAND	13.8	1	INLAND_6_UNIT	INLAND	LA Basin	8	Eastern
24111	PADUA	66	1			LA Basin	8	Eastern
24111	PADUA	66	2			LA Basin	8	Eastern
24140	SIMPSON	13.8	1	CHINO_6_SMPPAP	SIMPSON PAPER	LA Basin	8	Eastern
24160	VALLEYSC	115	1			LA Basin	8	Eastern
24815	GARNET	115	1	DEVERS_1_QF	Devers QFS	LA Basin	8	Eastern
24815	GARNET	115	2	DEVERS_1_QF	Devers QFS	LA Basin	8	Eastern
24826	INDIGO	115	1			LA Basin	8	Eastern
24921	MNTV-CT1	18	1	new unit	Mountainview Power Project	LA Basin	8	Eastern
24922	MNTV-CT2	18	1	new unit	Mountainview Power Project	LA Basin	8	Eastern
24923	MNTV-ST1	18	1	new unit	Mountainview Power Project	LA Basin	8	Eastern
24924	MNTV-CT3	18	1	new unit	Mountainview Power Project	LA Basin	8	Eastern
24925	MNTV-CT4	18	1	new unit	Mountainview Power Project	LA Basin	8	Eastern
24926	MNTV-ST2	18	1	new unit	Mountainview Power Project	LA Basin	8	Eastern
25422	ETI MWDG	13.8	1	ETIWND_6_MWDETI	ETIWANDA RECOVERY HYDRO	LA Basin	8	Eastern
25603	DVLCYN3G	13.8	3	DVLCYN_1_UNIT 3	DEVIL CANYON HYDRO UNIT 3	LA Basin	8	Eastern
25604	DVLCYN4G	13.8	4	DVLCYN_1_UNIT 4	DEVIL CANYON HYDRO UNIT 4	LA Basin	8	Eastern
25648	DVLCYN1G	13.8	1	DVLCYN_1_UNIT 1	DEVIL CANYON HYDRO UNIT 1	LA Basin	8	Eastern
25649	DVLCYN2G	13.8	2	DVLCYN_1_UNIT 2	DEVIL CANYON HYDRO UNIT 2	LA Basin	8	Eastern
28180	WINTEC8	13.8	1	INDIGO_1_UNIT 3	INDIGO PEAKER UNIT 3	LA Basin	8	Eastern
28190	WINTECX2	13.8	1	INDIGO_1_UNIT 1	INDIGO PEAKER UNIT 1	LA Basin	8	Eastern
28191	WINTECX1	13.8	1	INDIGO_1_UNIT 2	INDIGO PEAKER UNIT 2	LA Basin	8	Eastern
28260	ALTAMSA4	115	1			LA Basin	8	Eastern
22074	LRKSPBD1	13.8	1	LARKSP_6_UNIT 1	LARKSPUR PEAKER UNIT 1	San Diego	9	
22075	LRKSPBD2	13.8	1	LARKSP_6_UNIT 2	LARKSPUR PEAKER UNIT 2	San Diego	9	
22088	"BOULEVRD"	69	1			San Diego	9	
22092	CABRILLO	69	1	CBRLLO_6_PLSTP1	PT LOMA SEWAGE TREATMENT	San Diego	9	
22120	CARLTNHS	138	1	CHILLS_7_UNITA1	SYCAMORE LAND FILL (GRS)	San Diego	9	
22149	CALPK_BD	13.8	1	BORDER_6_UNITA1	CalPeak Power - Border LLC	San Diego	9	
22150	CALPK_EC	13.8	1	ELCAJN_6_UNITA1	CalPeak Power - El Cajon LLC	San Diego	9	
22153	CALPK_ES	13.8	1	ESCNDO_6_UNITA1		San Diego	9	
22172	DIVISION	69	1	DIVSON_6_NSQF	NAVAL STATION QF	San Diego	9	
22212	ELCAJNGT	12.5	1	ELCAJN_7_GT1	EL CAJON	San Diego	9	
22233	ENCINA 1	14.4	1	ENCINA_7_EA1	ENCINA UNIT 1	San Diego	9	
22234	ENCINA 2	14.4	1	ENCINA_7_EA2	ENCINA UNIT 2	San Diego	9	
22236	ENCINA 3	14.4	1	ENCINA_7_EA3	ENCINA UNIT 3	San Diego	9	
22240	ENCINA 4	22	1	ENCINA_7_EA4	ENCINA UNIT 4	San Diego	9	
22244	ENCINA 5	24	1	ENCINA_7_EA5	ENCINA UNIT 5	San Diego	9	
22248	ENCINAGT	12.5	1	ENCINA_7_GT1	ENCINA GAS TURBINE UNIT 1	San Diego	9	
22257	RAMCO_ES	13.8	1	ESCNDO_6_UNITB1	CalPeak Power - Enterprise LLC	San Diego	9	
22262	EPPCT1	18	1	new unit	Palomar Energy Project	San Diego	9	
22263	EPPCT2	18	1	new unit	Palomar Energy Project	San Diego	9	
22265	EPPST1	18	1	new unit	Palomar Energy Project	San Diego	9	
22332	GOALLINE	69	1	ESCO_6_GLMQF	GOAL LINE L.P.	San Diego	9	
22373	KEARN2AB	12.5	1	KEARNY_7_KY2	KEARNY GT2 AGGREGATE	San Diego	9	
22373	KEARN2AB	12.5	2	KEARNY_7_KY2	KEARNY GT2 AGGREGATE	San Diego	9	
22374	KEARN2CD	12.5	1	KEARNY_7_KY2	KEARNY GT2 AGGREGATE	San Diego	9	
22374	KEARN2CD	12.5	2	KEARNY_7_KY2	KEARNY GT2 AGGREGATE	San Diego	9	
22375	KEARN3AB	12.5	1	KEARNY_7_KY3	KEARNY GT3 AGGREGATE	San Diego	9	
22375	KEARN3AB	12.5	2	KEARNY_7_KY3	KEARNY GT3 AGGREGATE	San Diego	9	
22376	KEARN3CD	12.5	1	KEARNY_7_KY3	KEARNY GT3 AGGREGATE	San Diego	9	
22376	KEARN3CD	12.5	2	KEARNY_7_KY3	KEARNY GT3 AGGREGATE	San Diego	9	
22377	KEARNGT1	12.5	1	KEARNY_7_KY1	KEARNY GAS TURBINE UNIT 1	San Diego	9	
22384	KYOCERA	69	1	KYCORA_7_UNIT1	KYOCERA QF	San Diego	9	
22480	MIRAMAR	69	1	MSHGTS_6_MMARLF	MIRAMAR LAND FILL	San Diego	9	
22486	RAMCO_MR	13.8	1			San Diego	9	
22488	MIRAMRGT	12.5	1	MRGT_7_MR1A	Miramar GT 1A	San Diego	9	
22488	MIRAMRGT	12.5	2	TBD	MIRAMAR GEN (RAMCO)	San Diego	9	
22532	MURRAY	69	1	MURRAY_6_SDSU1	SAN DIEGO STATE UNIVERSITY	San Diego	9	

PF bus #	PF bus name	kV	PF Unit #	Resource ID	Resource Name	LCR Area Name	Area #	LCR Sub-Area Name
22576	NOISLMTR	69	1	NIMTG_6_NIQF	NORTH ISLAND QF	San Diego	9	
22604	OTAY	69	1	OTAY_6_UNITB	OTAY LAND FILL	San Diego	9	
22617	RAMCO_OY	13.8	1	OTAY_6_UNITA1	RAMCO Chula Vista	San Diego	9	
22660	POINTLMA	69	1	PTLOMA_6_NTCCGN	MCRD STM TURBINE	San Diego	9	
22680	R.SNTAFE	69	1			San Diego	9	
22688	RINCON	69	1			San Diego	9	
22704	SAMPSON	12.5	1	SAMPSN_6_KELCO1	KELCO QF	San Diego	9	
22724	SANMRCOS	69	1	SMRCOS_6_UNITB1	SAN MARCOS LAND FILL	San Diego	9	
22776	SOUTHBGT	12.5	1	SOBAY_7_GT1	SOUTHBAY GAS TURBINE 1	San Diego	9	
22780	SOUTHBY1	15	1	SOBAY_7_SY1	SOUTHBAY UNIT 1	San Diego	9	
22784	SOUTHBY2	15	1	SOBAY_7_SY2	SOUTHBAY UNIT 2	San Diego	9	
22788	SOUTHBY3	20	1	SOBAY_7_SY3	SOUTHBAY UNIT 3	San Diego	9	
22792	SOUTHBY4	20	1	SOBAY_7_SY4	SOUTHBAY UNIT 4	San Diego	9	
22820	SWEETWTR	69	1			San Diego	9	
22911	ENVIRE1	12.47	1			San Diego	9	
22912	ENVIRE2	12.47	1			San Diego	9	
22913	ENVIRE3	12.47	1			San Diego	9	

ATTACHMENT 2

Addendum
to
2006 Local Capacity Technical Analysis[1]

January 31, 2006

I. Overview of the Criteria for Locational Capacity Requirements (LCR)

The CAISO determines the LCR (in MWs for each defined local area) to permit the CAISO to meet its requirements, and be in compliance with established industry standards, within areas with severely limited transmission capability.

The technical analysis conducted for determining LCR for 2006 adheres to the CAISO Grid Planning Standards, which are based on national and regional planning standards, in particular the North American Electric Reliability Council ("NERC") and WECC Planning Standards.

The CAISO Planning Standards build from, rather than duplicate, the standards that were developed by WECC and NERC. The CAISO Planning Standards accomplish this by:

- Addressing specifics not covered in the NERC/WECC Planning Standards.
- Providing interpretations of the NERC/WECC Planning Standards specific to the CA ISO Grid.
- Identifying whether specific criteria should be adopted that are more stringent than the NERC and/or /WECC planning standards.

Policy summary

The criteria for LCR focuses on the transmission system's ability to meet existing industry standards including two contingencies: the worst contingency – i.e., the loss of a transmission line that would cause the biggest impact within that local area – and then the next most significant contingency. The LCR is the minimum amount of generating capacity that must be located within that local area to meet this standard -- so that, if such a worst contingency "event" occurred, the system could withstand the next worst contingency.

The NERC/WECC standards upon which this criteria are based are deterministic in the sense that these goals are clearly set *or determined* by industry professionals following an established process for identifying standards. An alternative probabilistic approach

[1] The California ISO's Local Capacity Technical Analysis: Overview of Study Report and Final Results, September 23, 2005, filed herewith, identified the methodology and criteria and the final LCR results for 2006. This report was submitted to the CPUC as part of the CAISO's Motion to Augment the Record Regarding Resource Adequacy Phase 2, filed September 23, 2005 in R.04-04-003, and can also be found at the CAISO website at: http://www.caiso.com/docs/2005/09/23/2005092316492428845.pdf

would establish the statistical probabilities that certain events could lead to certain outcomes, and then setting the appropriate policy based on those probabilities.

II. Peak Load Forecast: *Comparing 1-day-in-10 year and 1-day-in-5-year*

The peak load used for this 2006 LCR analysis is consistent with the peak load methodology used in the CAISO Grid Expansion Planning process:

- 1-day-in-2-year peak load for analyzing system-wide areas
- 1-day-in-5-year peak load for analyzing zonal areas
- 1-day-in-10-year peak load for analyzing areas smaller than a zone

For the 2006 LCR analysis, the 1-in-10-year peak summer load forecast is the most appropriate standard of analysis because fewer options exist during actual operation to mitigate performance concerns within local areas. There is less diversity and thus less certainty in load for local areas compared to a regional load forecast. In addition, this load level has been used as an industry standard in California and is used within the CAISO's transmission planning studies when determining if and what reinforcement of the transmission system is needed in future years in local areas.

As a general comparison: based on historical data,[2] the difference between the 1–in-10-year and the 1-in–5-year peak load is generally about 1.5%. In other words, the 1-day-in-5-year peak in MWs is about 1.5% lower than the 1-day-in-10-year peak in MWs. 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.

Policy Summary

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 LCRs.

[2] Includes the CEC's change in coincidental peak demand (MW) resulting from high temperatures scenarios, published in the "High Temperatures & Electricity Demand," July 1999.

III. Analysis of Contingencies

The LCR requirements have been determined using a subset of the CAISO Grid Planning Standards and are considered to be the minimum local generation requirement based on current operating practices. For most of the local areas, the LCR generation was determined such that following the outage of a single element (N-1), the system could be adjusted with local area generation to return power flows within the normal ratings of transmission equipment. As required, an additional generation readjustment was made to assure that the next transmission equipment outage (N-1-1) would not lead to exceeding the emergency ratings of the remaining transmission system.[3]

A. Operational Solutions to Meet the N-1, N-1 contingency:

The CAISO utilized generation to meet the applicable planning standards because the general definition of Local Capacity Requirement is the minimum generation capacity (in MWs) that must be available within each local area. However, it is possible, in limited cases, that additional generation readjustment beyond returning to normal ratings after the first contingency (N-1) would not be needed to prevent the second contingency (N-1-1) from exceeding the emergency ratings of the remaining transmission system. For example, if the transmission owner agreed to drop load[4] upon occurrence of a second contingency and the amount of load dropped would adjust power flows to be within transmission facility emergency ratings applicable for this outage combination, then additional generation may not be required, especially in areas with smaller load. In addition, new Special Protection Schemes might be installed such that compliance with the criteria is maintained at all times.

To illustrate the impact on LCRs using this alternative way for dealing with a second contingency: the following table is condensed from Table 2 (page 11) of the 2006 Local Capacity Technical Analysis that was submitted to the CPUC on September 23, 2005.

The second column in this table, "2006 market only LCR," represents the total generation that must be procured, based on the LCR criteria, assuming that all Muni, State, Federal, QFs and nuclear units are on-line and available to serve load. Footnote 2 explains a slight adjustment to the MW number cited for one local area in Table 2 (page 11) of the 2006 Local Capacity Technical Analysis. (PG&E staff helpfully guided the CAISO on this correction by providing the number of MWs used by QF/Muni generation.) This adjustment does not impact the overall 2006 LCR requirement or the total MW requirement for the Greater Bay Area.

The third column in the table below, "2006 Total LCR (MW)," is identical to the last column of Table 2 on page 11 of the 2006 Local Capacity Technical Analysis. The CAISO stands by the analysis and results that produced these MW requirements for 2006.

[3] The description of this methodology encompasses pages 6-10 of the overview report.

[4] Any commitment to drop load immediately following an N-1-1 event would need to be translated into clear operating procedures.

The fourth column in the table below, "Potential MW requirement decrease if load drop is feasible and implemented" affects mostly small areas where the LCR requirement was driven by an N-1-1 contingency. This occurs because the emergency rating of most transmission equipment is usually about 15-20 % higher than the normal rating. Thus, such small areas with fewer transmission ties are more susceptible to require additional system readjustment (after the first N-1 contingency) to get below the normal rating of transmission equipment and be able to support the second contingency within emergency ratings. In contrast, local areas with larger loads generally have many transmission ties. Therefore, once the system readjustment (the return to normal ratings after the first N-1 contingency) is completed, the local transmission equipment is more likely to sustain the second contingency without further readjustment because each one of the remaining ties may increase its flow by no more than 15-20%.

Table: Potential MW requirement decrease *if load drop is feasible and implemented for N-1-1 contingency.*

Local Requirements LCR			
Local Area Name	**2006 market only LCR (MW)**	**2006 Total LCR (MW)**	**Potential decrease in LCR (MW)**
Humboldt	126	162	0
North Coast / North Bay	518	658	98[3]
Sierra	808	1770[1]	0
Stockton	244	440[1]	98[4]
Greater Bay	4776[2]	6009	0
Greater Fresno	2529	2837[1]	0
Kern	171	797[1]	797[5]
LA Basin	4800	8127	0
San Diego	2434	2620	0
Total	**16406**[2]	**23420**	**993**

[1] Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR

[2] There is a small change to the total market only LCR because of QF/MUNI units that have been recounted. The Greater Bay Area market requirement goes up to 4776 MW because the power generated by QF and MUNI actual is a bit lower at 1233 MW.

[3] Under the assumption that load drop is feasible and implemented for an N-1-1 contingency: the Eagle Rock- Fulton sub-area requirements could go down from 319 to 238 MW (includes 79 MW of QF and MUNI), and the Lakeville (total) requirement could be reduced from 658 to 560 MW (which includes 140 MW of QF and MUNI)

[4] Under the assumption that load drop is feasible and implemented for an N-1-1 contingency: the Tesla-Bellota sub-area requirements could go down from 348 to 328 MW (includes 194 MW of QF and MUNI), and the Lockeford requirement could be reduced from 92 to 14 MW (which includes 2 MW of QF and MUNI). Note that these requirements were calculated correctly in the main ”Table 2” of the 2006 LCR report; however, the detailed description for the Tesla-Bellota sub-area (page 18) has an incorrect (higher) MW requirement.

[5] Both the Kern PP sub-area and the Weedpatch sub-area could be eliminated under the assumption that load drop is feasible and implemented for an N-1-1 contingency.

Policy summary

This fourth column, within the table above, shows the impact on the LCR if operational solutions (like load shedding or Special Protection Schemes) were used to meet the criteria instead of required MWs within the local area. The LCR in three of the nine local areas could be reduced. The total LCR of 23,420 MWs could be lowered by approximately 1000 MWs.

B. **For N-1, N-2 contingency:**

The proposed LCR requirements will also allow for recovery from simultaneous or overlapping contingencies that require generators inside the load pocket be used to prevent voltage collapse, transient instability, cascading outages and uncontrolled separation for the loss of a single element (N-1), system readjustment (without pre-contingency interruptible or firm load shedding), and then the simultaneous loss of credible two transmission lines (Double Circuit Tower Lines or in the same Right-Of-Way). This is a N-1, N-2 contingency. The 2006 results showed that only one sub-area has its LCR requirement driven by this portion of the criteria – the LA Basin Eastern sub-area.

The LA Basin East LCR requirement is driven by a single outage (Devers-Valley 500 kV line or one SONGS unit) followed by the need to stay within the accepted rating (by both CAISO and SCE) for the South of Lugo 500 kV path. This requirement also translates into a single element, system readjustment, and then the simultaneous loss of credible two transmission lines, because the rating of the South of Lugo 500 kV path is driven by the simultaneous loss of the Lugo-Mira Loma #2 and #3 500 kV lines and preventing subsequent voltage collapse.

Policy Summary

If the path rating within the LA Basin is not maintained and the double contingency occurs, the Southern California region and potentially the entire WECC area could be subjected to a severe black-out. The assessment of technical consequences concluded that the South of Lugo path rating needs to be maintained within limits at all times, including one element out of service, through resource procurement until the import capability into this area is raised by new transmission projects. At that time, this requirement will need to be reassessed.

IV. 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 13.2. Future studies can be conducted with any version higher or equal with 13.2 – for example 14 or 15. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

The CAISO utilized the "2006 CAISO Controlled Grid – Summer Peak" as the starting base case for the 2006 local area power flows used in the 2006 LCR studies. To complete the local area component of this study, this base case was adjusted to reflect 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 2006. 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.

Policy summary
The power flow program used to analyze the contingencies is publicly available.

V. 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.[5]

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

[5] *MORC simply 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."*

- **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.

- **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

Policy Summary

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.

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, Proposal of The California Independent System Operator Corporation Regarding Local Resource Adequacy Requirements in Docket No. R.05-12-013.

Executed on January 31, 2006, at Folsom, California.

Charity N. Wilson
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