March 31, 2003

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

[PUBLIC VERSION]

Re: California Independent System Operator Corporation
Docket No. ER03-____-000
Amendment No. 50

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Sections 35.11 and 35.13 of the Federal Energy Regulatory Commission's ("Commission") rules and regulations, 18 C.F.R. §§ 35.11, 35.13, the California Independent System Operator Corporation ("ISO")[1] respectfully submits for filing an original and six copies of an amendment ("Amendment No. 50") to the ISO Tariff.

Simultaneously with the instant filing, the ISO is submitting a version of Amendment No. 50 that contains confidential information in **Attachment G** to the transmittal letter. In the instant filing, Attachment G has been redacted. In all other respects, the version of Amendment No. 50 to be released publicly (*i.e.*, the instant filing) is identical to the version of Amendment No. 50 for which confidential treatment is being requested.

Amendment No. 50 would modify the Tariff in several respects. For ease of reference, the proposed changes can be divided into market changes and changes related to the provision of data.

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[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, ISO Tariff Appendix A, as filed August 15, 1997, and subsequently revised.

The ISO proposes to make market-related changes to the ISO Tariff to provide for a means to improve management of Intra-Zonal Congestion until the ISO implements Locational Marginal Pricing ("LMP") or some other long-term comprehensive solution.[2]

The ISO also proposes to make data sharing changes to the ISO Tariff to allow the ISO to share Generator Outage information with entities operating transmission and distribution systems affected by the Outage.[3]

The ISO respectfully requests that the Commission put these proposed amendments into effect within sixty days. As discussed further below, the ISO also requests that the Commission convene a technical conference as soon as possible to develop an alternative approach to dealing with Congestion caused by the interconnection of new generating units and, at least in part, by System Resources.

I. THE PROPOSED AMENDMENTS

The proposed modifications to the ISO Tariff have been approved conceptually by the ISO Board of Governors. They are designed to enhance real time operations and reliability, reduce opportunities for gaming, and reduce the administrative burden on ISO staff.

A. Market Changes

1. Interim Intra-Zonal Congestion Management

a. Background

On January 31, 2002, the ISO filed proposed Amendment No. 42. That Amendment included, *inter alia,* a proposal for an interim means to manage Intra-Zonal Congestion until the ISO could reform its zone-based Congestion Management system permanently. The Commission rejected this part of Amendment No. 42 on March 27, 2002, explaining the proposal was

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2 Revised ISO Tariff sheets reflecting the changes proposed to implement the improvements to Intra-Zonal Congestion management are contained in Attachment A. Black-lines showing the proposed Intra-Zonal congestion management changes are provided in Attachment B.

3 ISO Tariff sheets regarding sharing Generator Outage information are contained in Attachment C. Black-lines identifying the proposed changes are provided in Attachment D.

premature in light of the anticipated ISO filing of the ISO's market redesign proposal on May 1, 2002.[4]

Subsequently, on May 1, 2002, the ISO filed proposed Amendment No. 44, the MD02 comprehensive market redesign proposal ("MD02 Filing"). In Amendment No. 44, the ISO indicated its intent to move away from its previous zonal Congestion Management methodology in favor of using LMP at each system node as a method to manage Congestion. In addition, the ISO proposed a system-wide cap on negative decremental bids of negative $30/MWh. The ISO also proposed unit-specific bid caps that would apply in situations where resources are situated to exercise local market power. In support of its proposed local market power mitigation measures, the ISO submitted an Affidavit by Dr. Eric W. Hildebrandt. Dr. Hildebrandt stated in his MD02 Affidavit that suppliers with local market power routinely submit negative decremental bids that are far in excess of any variable production costs incurred in connection with reducing a unit's output, and that the ISO often is forced to accept such bids because competitive alternatives are not available.[5] This results in the ISO paying the supplier to reduce output. Dr. Hildebrandt provided several examples of generators exercising local market power by playing the "DEC game". MD02 Affidavit at page 7. The "DEC game" continues today because the existing market rules and local market power mitigation measures are inadequate.

The Commission, in its July 17, 2002 order[6] on the MD02 Filing, authorized the ISO to proceed to develop an LMP-based Congestion Management system. July 17 Order at ¶ 117. The Commission also noted that it would defer action on interim Intra-Zonal Congestion Management until the ISO filed a definitive proposal. *Id.* at ¶ 104.

Further, the July 17 Order directed modifications to the ISO's proposed Automatic Mitigation Procedures ("AMP") to mitigate local market power. Specifically, the July 17 Order: (1) established a $91.87/MWh price screen so that no bid below $91.87/MWh taken out of merit order due to local reliability needs would be mitigated; (2) indicated that no bid above $91.87/MWh taken out of merit order for local reliability needs would be mitigated unless it exceeded the Market Clearing Price ("MCP") by 200 percent or $50/MWh;

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4 *California Independent System Operator Corporation*, 98 FERC ¶ 61,327, 62,380 (2002).

5 Specifically, because of their local market power, certain suppliers have been called out-of-sequence (*i.e.,* not in economic merit order) and are paid prices for decremental Energy that are significantly lower than the Real Time Imbalance Energy Market Clearing Price and the suppliers' own marginal costs for production of such decremental Energy.

6 *California Independent System Operator Corporation*, 100 FERC ¶ 61,060 (2002) ("July 17 Order").

and (3) directed that any bid exceeding the levels set in market impact tests would be mitigated to its reference price and could not set the MCP. *Id.* at ¶ 93.

In its October 11 order on rehearing of the July 17 Order,[7] the Commission eliminated the application of the $91.87/MWh price screen to bids that are taken out of merit order to address Intra-Zonal Congestion. October 11 Order at ¶ 41.

In its July 17 Order, the Commission also approved the system-wide negative decremental bid cap proposed by the ISO. July 17 Order at ¶ 135. The Commission did not approve, however, the ISO's proposed mitigation measures designed to address the "DEC game". In the October 11 Order, while the Commission noted the ISO's concern that the system-wide negative cap was insufficient to mitigate local market power, the Commission declined to take any action other than to state that the ISO could propose to amend this cap. October 11 Order at ¶ 45.

Even though the Commission has approved certain ISO Tariff revisions designed to mitigate the exercise of local market power, such revisions are inadequate, and the ISO is still plagued by the following problems:

1) The ISO still has no process for managing Intra-Zonal Congestion in the forward markets. This means the ISO must try to resolve Intra-Zonal Congestion in real-time. Managing Intra-Zonal Congestion in real-time places an undue burden on the ISO's real-time operating staff and introduces serious potential reliability problems. Provided as Attachment E to the instant filing is an Affidavit by Jim McIntosh, ISO Director of Grid Operations detailing the nature and magnitude of the problems caused by waiting until real-time to manage Intra-Zonal Congestion.

2) A Generator with a Generating Unit that may be the only resource whose output the ISO can reduce to mitigate Intra-Zonal Congestion can exercise local market power and earn a payment of $30/MWh *to reduce its output* in addition to whatever fuel savings it may realize by such output reduction.[8]

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7 *California Independent System Operator Corporation*, 101 FERC ¶ 61,061 (2002) ("October 11 Order").

8 The Commission has recognized that in California there are conditions where no effective competition exists to relieve certain transmission constraints giving rise to Intra-Zonal Congestion, and there is no market discipline on the price bid by a generator possessing the ability to reduce its schedule. *California Independent System Operator Corporation,* 90 FERC ¶ 61,001 at 61,011 (2000).

3) A Generator with a Generating Unit that may be the only unit whose output the ISO can increase to mitigate Intra-Zonal Congestion can charge a premium of up to $49.99/MWh above its reference price with no possible consumer recourse.[9]

The Commission should not countenance these deficiencies. The ISO needs assistance **now** to address Intra-Zonal Congestion and local market power issues. Moreover, while local market power modifications to AMP and the -$30/MWh negative decremental cap loosely bound the exercise of local market power, such measures are inadequate and in no way prevent the exercise of local market power. Moreover, they do not address the ISO's reliability concerns. The ISO must have a workable, interim solution until LMP or some other long-term comprehensive solution is implemented.

The ISO is especially susceptible to the "DEC game" in the absence of a security-constrained Day-Ahead nodal Energy market. In that regard, the ISO cannot limit Schedules based on localized constraints but would be required to reduce Generation in real-time. Thus, if there is a transmission contingency such as a facility derating or outage and, as a result, a local Generation pocket is constrained, a Generator can submit a Schedule for Generation in excess of the constrained transmission capacity in the ISO's Day-Ahead Market, and the ISO would be required to reduce such a Schedule in Real Time. Under these circumstances, Generators are able to submit high negative DEC bids that bear no relation to the fuel cost savings realized by reducing the unit's output because there is no other unit on which the ISO can call due to the lack of competition in the constrained pocket. The ISO would have no other alternative but to pay the Generator to reduce the unit's output.

Because such circumstances occur regularly, it is imperative that the ISO have adequate measures in place to address the "DEC game". Although the negative $30/MWh cap on DEC bids approved by the Commission applies system-wide, the cap is not primarily intended -- nor is it sufficiently effective -- to prevent the "DEC game". The negative $30 cap on DEC bids was proposed primarily to address ISO Control Area (system-wide) Over-generation. The negative cap does not provide adequate protection against local market power. In the local market power context, no competition exists

[9] The Commission previously has recognized that there are locations in California where certain suppliers have local market power because other generators cannot provide service in the Load pocket. *AES Southland, Inc. and Williams Energy Marketing and Trading Company,* 94 FERC ¶ 61,248 at 61,871-72 (2001). Dr. Hildebrandt also indicated in his MD02 Affidavit that, on numerous occasions, generators have played the "INC" game and bid capacity at a very high price in the Real Time market thereby forcing the ISO to meet local reliability requirements by dispatching generation out-of-sequence at uncompetitive, high prices. MD02 Affidavit at 4-5.

in the DEC market. The Commission has noted that in a well-functioning, competitive market, suppliers generally would compete in the decremental Energy market by submitting positive decremental bids that reflect a Generator's avoided costs. Indeed, the Commission has recognized:

> [i]n a competitive situation, a generator would set its bid at the level of costs it can avoid by not generating. Because each generator has been paid the market clearing price for its commitment to operate in real-time, each generator would be indifferent to operating and incurring running cost, or not operating and paying the ISO an amount equal to its running cost.

California Independent System Operator Corporation, 90 FERC ¶ 61,006 at 61,012 (2000).

In the circumstances that exist in California, as described herein, however, any "constrained" Generator can submit negative DEC bids that the ISO is generally forced to accept. The negative $30/MWh cap does not provide adequate protection in these circumstances. The AMP do not provide adequate protection, either, since the AMP do not apply to decremental bids. Because the market is not competitive in a constrained Generation pocket, greater protection than the negative $30/MWh bid cap is necessary to mitigate market power in connection with DEC bids.

While the "DEC game" remains an ongoing concern, suppliers still continue to exercise local market power through other means than the "DEC game". The Affidavit of Dr. Eric Hildebrandt (Attachment F) and confidential report (Attachment G) included with this filing describe a recent event in which a supplier apparently exercised market power through the outage of a generating unit. The opportunities to exercise market power either through the "DEC game" or by inflating the prices for a particular generator needed for local reliability still exist.

The need for effective management of Intra-Zonal Congestion is so acute that, on September 12, 2002, the Market Surveillance Committee of the ISO ("MSC") filed in Docket No. ER02-1656 a paper entitled "Comments on Mitigating Local Market Power and Interim Measures for Intra-Zonal Congestion Management" ("MSC Comments"). In that document, the MSC stated:

> We believe that by putting in place a mechanism that automatically mitigates the bids of unit owners with local market power, the economic incentive to intentionally submit infeasible schedules and the incidence of intra-zonal congestion will be significantly reduced.

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> To deal with these reliability concerns, the CAISO could combine its desire to curtail overscheduled generation in advance with a process for achieving such curtailment in an efficient manner. Using the mitigated bids of units with local market power as intra-zonal adjustment bids could achieve this. Instead of curtailing schedules according to a pro-rata measure, the adjustments would occur in accordance with the ordering of the adjustment bids. . . . Specifically, after the close of the hour-ahead market, the ISO could use the mitigated adjustment bids for those units with local market power and the unmitigated adjustments bids of the remaining firms to compute final hour-ahead schedules that are feasible from both an intra-zonal and inter-zonal transmission constraints. In the event that suppliers submit hour-ahead schedules that are feasible from both an intra-zonal and inter-zonal perspective, this process would not be necessary.

MSC Comments at 4.[10]

b. Proposed Modification

The process recommended by the independent MSC is what the ISO now proposes to implement as an interim process to manage Intra-Zonal Congestion. The process the ISO proposes will be applied to all instances of Intra-Zonal Congestion. That is, the process will be applied when foreseeable Congestion arises as a result of planned maintenance work, and thus is foreseeable before the ISO Day-Ahead Market. The proposed solution for Intra-Zonal Congestion also will be used when Congestion arises after the close of the ISO Day-Ahead Market, due to real-time changes in System Conditions, such as Forced Outages. The proposal is as follows:

1) In cases where the ISO foresees Intra-Zonal Congestion due to abnormal system conditions (such as transmission maintenance), the ISO would publish the total allowable output for a Generating Unit or group of Generating Units constrained by the same intra-zonal interface by 1800 hours two days before the operating day. As needed, the ISO also may update that information following the close of the Day-Ahead market the day before the operating day. This information would allow the Generator or Generators to submit Hour-Ahead Schedules that conform to the ISO's published limits.

10 The MSC Comments are included with this filing as Attachment H.

2) If the Generator or Generators submit Hour-Ahead Schedules that conform to these published limits, the ISO would take no further action.

3) If the Final Hour-Ahead Schedules cause Congestion, the ISO will create proxy Energy bids for each thermal unit affecting the constrained interface based on: (1) the unit's heat rate curve; (2) the same monthly bid-week average price of natural gas at California border delivery points approved by the Commission for use during the price mitigation provisions that were in place through October 29, 2002; and (3) a figure of $6.00/MWh for variable operations and maintenance costs.[11] The ISO will use, as the proxy Energy bid for non-thermal units, the unit's reference price as determined by Potomac Economics, Ltd., the independent entity under ISO contract to calculate reference prices for the ISO's AMP.

4) The ISO will Dispatch these proxy Energy bids based on cost, effectiveness on the constraint, and other factors (such as Energy limitations, hydrological conditions, etc.) to alleviate the constraint immediately after Final Hour-Ahead Schedules are issued. The ISO will not dispatch any Reliability Must-Run ("RMR") Unit below its required reliability operating level. The ISO will not adjust Qualifying Facility Generation unless such adjustments are unavoidable. The ISO proposes to Dispatch proxy bids after the close of the Hour-Ahead bids to relieve Congestion regardless of whether this Congestion was caused by abnormal system conditions and the ISO had published projected limits in advance, or whether the Congestion arose due to changes in conditions closer to real time and therefore the ISO had not published any limits. The ISO's ability to mitigate local market power must not be conditioned on the ISO's ability to predict perfectly when Intra-Zonal Congestion will occur.

5) Additionally, the ISO proposes that it be able to Dispatch units both to higher operating levels (incremental Dispatch) and to lower operating levels (decremental Dispatch), depending on the nature of the Intra-Zonal Congestion that must be addressed.

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[11] The MSC recommends using a cost-based bid rather than the unit's reference price for the mitigated bid. *See* MSC Comments at 3-4. The ISO proposes to use reference prices only for non-thermal resources that have not submitted cost data to the ISO.

6) The ISO will pay incremental bids Dispatched at the greater of (1) 110 percent of the price of the mitigated bid or (2) the zonal BEEP Interval Ex Post Price. The ISO will charge decremental bids Dispatched at the lesser of (1) 90 percent of the price of the mitigated bid, or (2) the zonal BEEP Interval Ex Post Price. This settlement (1) reflects the inaccuracies inherent in identifying a Generating Unit's costs using a cost-based proxy bid,[12] (2) will keep the Generator whole to the price it would have received had the ISO Dispatched the unit in merit order, and (3) prevents the Generator from exercising local market power.

Consistent with the MSC's recommended approach, this ISO proposal allows Generators to self-manage Intra-Zonal Congestion by submitting Schedules that conform (in aggregate) to the aggregate limits published by the ISO. Ultimately, if Generators do not self-manage the Congestion, the ISO, using mitigated bids, will pre-Dispatch Generating Units from their Final Hour-Ahead Schedules to feasible operating points.

The ISO proposal to use mitigated bids to manage Intra-Zonal Congestion and mitigate local market power is similar to Commission-approved procedures used in all other independent system operators.[13] This is reasonable and appropriate. The use of mitigated bids forecloses the opportunity to exercise local market power in the face of inadequate local supply competition because the ability to exercise local market power does not depend on whether Congestion is managed using a zonal or a nodal Congestion management process. Local market power does not arise from the type of Congestion Management scheme used. Rather, local market power arises when there is only one (or a few) generating unit(s) that can be called on to address local reliability supply requirements.

In June 2001, PJM filed a proposed amendment to its operating agreement and tariff that would extend PJM's existing authority to cost-cap must-run units beyond the day-ahead market to the real-time market, as well. PJM stated that its experience over the last few years shows that it also should have the ability to cost-cap must-run units in real time, in order to prevent the exercise of market power if a transmission constraint should

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12 PJM similarly caps a unit's bid at 110 percent of the unit's cost when the unit must be operated out of merit order for local reliability reasons. *See* PJM FERC Electric Tariff Section 6.4.2 (ii), at Sheet 263.

13 *See, e.g., New England Power Pool, ISO New England*, 100 FERC ¶ 61,287 (2002).

occur unexpectedly, so as to render a resource a must-run unit unexpectedly.[14]

The Commission approved this request on August 28, 2001, stating:

> If, however, a transmission constraint occurs so as to make that unit a must-run resource, the generator could earn its high price, and that price would also become the LMP for the particular load pocket for that day. As PJM notes in its answer, this scenario has, in fact, occurred. PJM's MMU thus concluded that PJM should have the authority to cost-cap must-run units in real time in order to prevent the exercise of market power, and this proposal was approved by PJM's stakeholders. We find that PJM has persuasively demonstrated that, absent the authority to cost-cap in real time, consumers would be subject to the exercise of market power by generators, and that PJM requires authority to cost-cap must-run units in real time to prevent the exercise of market power in real time.
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> While no one (including PJM) can predict precisely when and where a transmission constraint may occur in real time, as stated above, a generator located within a load pocket can assume that a transmission constraint may occur so as to make its unit a must-run resource. Moreover, as described above, a generator need not predict with certainty that it will be designated a must-run resource in order to be able to exercise market power -- it need only bid its generation into the market at an excessively high price, and over the course of time, it will, likely, at certain times, be designated a must-run resource. Thus, the fact that generators cannot predict exactly when they might be designated a must-run resource does not eliminate the need for PJM to be able to cost-cap units in real time so as to prevent must-run generators from exercising market power.

PJM Interconnection, LLC, 96 FERC ¶ 61,233 at 61,936 (2001) (footnote omitted).

Again, the Commission's order cited above and PJM's arguments on which it was based directly apply to the ISO, because the ability to exercise local market power does not depend on the granularity of the Congestion

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[14] PJM defines must-run units as "generation resources that. . . as a result of transmission constraints. . . must be run to ensure the reliability of service in the PJM control area". PJM FERC Electric Tariff at 261.

Management scheme used. Thus, any independent system operator's ability to mitigate out-of-merit-order bids that could otherwise exercise market power is essential. Accordingly, the Commission should approve the ISO's primary proposal.

As described in the Affidavit of Jim McIntosh (Attachment E), the ISO must manage foreseen Intra-Zonal Congestion before real time. It is irresponsible for the ISO to allow foreseen transmission overloads – *i.e.,* Congestion – to occur in real-time simply because the ISO's admittedly flawed original market design contained no mechanism to mitigate Intra-Zonal Congestion in the forward markets. Managing known Intra-Zonal Congestion in the forward markets will not eliminate all Intra-Zonal Congestion, since some Intra-Zonal Congestion will occur in real time due to events that happen after the forward markets are run. The ISO's proposal to Dispatch units on mitigated bids before real time (the same approach taken by other ISOs) will reduce the amount of Intra-Zonal Congestion that must be dealt with in real time and mitigate the market power that can be exercised in such cases.

The ISO now proposes to manage Intra-Zonal Congestion until LMP or some other long-term comprehensive solution is implemented in a manner consistent with the MSC's proposed approach and with the processes used by other independent system operators. The ISO respectfully requests the Commission to grant the ISO this authority and provide the ISO with a vital tool to reduce the burden and operational problems associated with managing known Intra-Zonal Congestion in real-time and to prevent the costly exercise of local market power.

c. <u>Description of Proposed Tariff Changes</u>

Section 2.2.2 (e) now indicates that the ISO will manage Inter-Zonal Congestion as according to the existing provisions and Intra-Zonal Congestion according to provisions contained in the instant amendment.

Section 2.2.10.7 provides for notification of forecast limits to Scheduling Coordinators by 1800 hours two days prior to the operating day.

Section 2.2.12.5 was modified to indicate that Generating Units no longer will be Dispatched to mitigate Intra-Zonal Congestion based on Adjustment Bids, since they only will be Dispatched according to the proxy energy bids described in Section 7.2.6.1.

Sections 7.2.1.4 and 7.2.6.2 were modified to clarify that the only Congestion that will be modified in the Hour-Ahead and Day-Ahead markets using Adjustment Bids will be Inter-Zonal Congestion. Intra-Zonal Congestion will be managed according to 7.2.6.1.

Section 7.2.4.1.4 was modified to clarify that Adjustment Bids only from System Resources and Dispatchable Loads will be used to manage Intra-Zonal Congestion.

Section 7.2.6.1 sets forth the bulk of the process the ISO will use to manage Intra-Zonal Congestion as described above in subsection (b).

Section 7.3.2 now indicates that the ISO will manage Intra-Zonal Congestion according to the provisions of Section 7.2.6.1, and will settle resources Dispatched to manage Intra-Zonal Congestion in accordance with amended Settlement and Billing Protocol Appendix B.

Dispatch Protocol Sections 8.2 and 8.4 were modified to clarify that the only Congestion that will be modified in the Hour-Ahead and Day-Ahead markets using Adjustment Bids will be Inter-Zonal Congestion. Intra-Zonal Congestion will be managed according to 7.2.6.1.

Dispatch Protocol Section 8.6.2 was modified to indicate that Imbalance Energy bids and Adjustment Bids from System Resources and Dispatchable Loads only (not from Generating Units) will be used to manage Intra-Zonal Congestion.

Schedules and Bids Protocol Section 2.1.1 (g) was modified to clarify that Adjustment Bids for Generating Units only will be used to manage Inter-Zonal Congestion. The only bids the ISO will Dispatch to manage Intra-Zonal Congestion from Generating Units will be proxy energy bids.

Schedules and Bids Protocols Section 4 was modified to clarify that 1) Adjustment Bids are used for Inter-Zonal Congestion in the forward markets and 2) Adjustment Bids from System Resources and Dispatchable Loads, not Generating Units, will be used to manage Intra-Zonal Congestion.

Scheduling Protocol Section 7.2.2 was modified to clarify that the ISO's Congestion Management Software uses Adjustment Bids to manage Inter-Zonal Congestion only in the forward markets.

Scheduling Protocol Section 10.1 has been changed to indicate that the ISO will manage Intra-Zonal Congestion according to the provisions of Section 7.2.6.

Scheduling Protocol Section 11.3 was modified to indicate that Imbalance Energy bids and Adjustment Bids from System Resources and Dispatchable Loads only (not from Generating Units) will be used to manage Intra-Zonal Congestion.

Settlement and Billing Protocol Appendix B has been modified to reflect the settlement for Generating Units described in subsection (b) (6). The ISO does not propose any change to how costs of managing Intra-zonal Congestion will be allocated.

d. <u>Application of the Proposed Amendment to Locations Within the ISO Control Area Where Siting of New Generation Causes Near Continuous Congestion and Where System Resources Contribute to the Intra-Zonal Congestion</u>

The ISO increasingly confronts Congestion caused by siting of new Generating Units in areas lacking adequate transmission facilities to deliver the new Generation. A significant case in point concerns two new Generating Units under ISO Participating Generator Agreements that are located in Mexico but connected to the ISO Controlled Grid. Energy from these new Generating Units, combined with the existing Energy that is imported regularly from a neighboring Control Area, is expected to cause severe congestion within the ISO Control Area.[15] The Congestion is projected to occur on the 500/230 kV transformer bank at San Diego Gas & Electric's Miguel substation. This transformer bank is located near San Diego at the western terminus of the Southwest Power Link, a 500 kV transmission line from Palo Verde Generating Station in Arizona. The new Generation at Termoelectrica de Mexicali, S. De R.L. de C.V and Termoelectrica US, LLC, and the InterGen La Rosita facilities, feeds into the Imperial Valley Substation, one bus east of Miguel substation. The combined amount of power that is predicted to try to flow across the Miguel bank from the generating units in Mexico and imported from Arizona on the SWPL will far exceed the capability of the 500/230 kV transformer bank at Miguel. The ISO currently estimates that it will have to curtail more than 500 MW of Energy at least twelve hours each day to mitigate Congestion after these Generating Units are placed in full commercial service on June 1, 2003. The provisions of this instant amendment, applied to this situation, would allow the ISO to pre-Dispatch mitigated cost-based bids from the new Generating Units (and any other Generating Units from Participating Generators that are effective in relieving the Congestion) immediately after publication of Final Hour-Ahead Schedules.

The ISO anticipates that it will confront similar instances of new Generating Units locating within the ISO Control Area where the transmission grid is inadequate to deliver the new Generation, existing Control Area Generation, and imported Energy from System Resources. For example, the Drum generation area and Summit Interconnection on Path 24 are predicted

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[15] *See* Motion to Intervene and Comments of the California Independent System Operator Corporation, filed in Docket ER03-217 on December 16, 2002, at page 4.

to be Congested regularly when new Generating Units come on-line later this year and next year. As discussed in the following section of the instant filing, the ISO requires new Congestion Management tools that take into account the Energy that is imported by System Resources in addition to Generation from internal Generating Units.

In summary, the provisions of the instant amendment are applicable only to Generating Units under Participating Generator Agreements with the ISO. Inasmuch as System Resources supplying the ISO across an intertie lend themselves to competitive solutions with regard to Congestion management, System Resources are not implicated in this proposal. The ISO does not propose to mitigate Bids from System Resources used to manage Intra-Zonal Congestion. The ISO similarly does not propose to mitigate bids from Dispatchable Loads to manage Intra-Zonal Congestion, since Dispatchable Loads, unlike Generating Units, do not have a known cost-basis from which to create a mitigated bid. Critically, given that the vast majority of Intra-Zonal Congestion problems currently facing the ISO are situations within the ISO Control Area that involve only one or two Generators and do not involve System Resources or Dispatchable Loads, the consequences of not applying the provisions of this instant amendment are much greater than any potential concern that Participating Generating Units are subject to different operational rules than are System Resources and Dispatchable Loads. Without the provisions of this amendment, the ISO expects to have to Dispatch several hundred MW of un-mitigated market DEC bids in the sixty minutes before the operating hour to relieve the Congestion described above. The ISO estimates that the costs of mitigating this Congestion without the provisions proposed herein could exceed $4 million a month if suppliers bid decremental energy at the current floor of negative $30/MWh.

For all of the above detailed reasons the ISO proposes to resolve Intra-Zonal Congestion before real-time by first permitting Participating Generators to mitigate the Congestion competitively amongst themselves and to pre-Dispatch cost-based energy bids to mitigate the Intra-Zonal Congestion if Participating Generators do not mitigate the Congestion themselves.

e. Request for Technical Conference

As discussed supra, in the short term, the ISO sees no other alternative beyond the instant proposal to address the operational and market power problems that will arise as early as June 1, 2003 when the new Generating Units in Mexico seek to begin full commercial operations. The most viable long-term solution to this problem, apart from upgrading the transmission system at Miguel to remove the bottleneck, would be to use an LMP-based system or some other long-term comprehensive solution in the forward markets that would (1) allow System Resources and Participating

Generators to compete for the scarce transmission into San Diego and (2) ensure forward schedules did not create the Congestion. This also appears to be a robust solution to the other areas within the ISO Control Area that the ISO predicts will be Congested due to new Generation competing with existing Generation and imported Energy for limited transmission capability.

Therefore, while it is essential that the Commission put the provisions of this Amendment into effect prior to June 1, 2003, the ISO respectfully urges the Commission to convene a technical conference as soon as possible to consider other alternatives to deal with this problem in the time between when this Amendment in put into effect and an LMP-based congestion Management or some other long-term comprehensive solution can be implemented.

B. Sharing Generator Outage Information with Affected Operating Entities

1. Background

In bulk power system operations, transmission service and Generation Dispatch are integrated and interdependent. While the transmission grid provides Generating Units access to serve load, the real and reactive power output from Generating Units may prevent overloads, maintain voltage, and ensure transient system stability. In many areas of the grid, certain conditions require specific Generating Units to operate. In some cases, the ability to perform transmission maintenance and still comply with reliability criteria depends on the operation of one or more particular Generating Units.

In many cases, transmission work is scheduled and arranged around pre-established Generating Unit outages. Scheduled Generating Unit Outages are usually established before the specifics are known for anticipated transmission work. This is partly due to the physical and business differences between transmission and generation. Generation work usually relies on contract laborers and manufactured parts that must be ordered far in advance. Furthermore, in the ISO Control Area, Generation work involves a field of multiple Scheduling Coordinators competing for available Maintenance Outage, or "clearance" windows. Because of these factors, a large portion of Generating Unit Outages are usually required to fit into fixed windows of time and tend to be known and scheduled well in advance. In contrast, transmission work typically (1) involves only a single Participating Transmission Owner, (2) is conducted by in-house utility crews, (3) takes place simultaneously in many different locations, and (4) often draws upon parts readily available in stock. Because of these attributes, planned transmission work is usually more flexible than planned Generation work – specific job sites and dates may not be known beyond 60 days, and even within this near-term[16] window, the transmission work plan is flexible enough that it can be shaped around existing Generating Unit Outages.

Participating TOs are required to submit general transmission construction plans 30 days in advance of the start of construction. After the ISO reviews the construction plan, it can assess any general conflicts

[16] Outages can be regarded as one of three types: near-term scheduled, long-term scheduled, and forced. In general, the ISO, Generators, and Transmission Owners have experienced fairly good success in forward-scheduling "big" outages (outages of significant duration, capacity size, or scope) in the long-term outage plan (12-15 months). These outages are usually known far in advance and follow a fixed schedule. Still, unexpected outages of transmission or generation equipment are inevitable, and the respective parties do their best to shuffle the conflicting clearances to accommodate these sudden system changes.

between a Participating TO and generator outage plans. Thereafter, the ISO will communicate with the Participating TOs and Generators and deal with apparent conflicts in an attempt to work around clearances.

Thus, although a typical transmission work plan is flexible enough that it can be shaped around existing Generating Unit outages, the ISO must take great care in coordinating transmission and generation outages. Indeed, even up to the last minute, the ISO must be in communication with the affected Participating TO and Generator(s) to address potential adverse consequences that have not been foreseen by either the Participating TO or the Generator.

In many cases ISO Outage Coordinators and Operations Engineers coordinate transmission clearances around established Generating Unit Outages. For many transmission clearances, the availability or absence of local reliability Generating Units dictates whether or not the transmission work can actually be performed. While the ISO's Operations Engineering group is constantly performing power flow studies to analyze upcoming transmission Outages to meet this responsibility, the volume of this essential ongoing work, coupled with the complication that the outage often crosses jurisdictional boundaries,[17] requires the ISO to rely upon the operations engineering experience and expertise of both the Participating TOs and other operating entities in adjacent Control Areas (such as the Bonneville Power Administration) to assist the ISO with performing and validating these studies. The power flow studies require data on: (1) expected Load; (2) expected network configuration (*i.e.*, what transmission equipment is out of service); and (3) Generating Unit status.

Based on the ISO's experience, it is essential that the ISO be able to discuss relevant, established Generating Unit Outages with other operating personnel when necessary to allow them to schedule transmission work in the appropriate windows. In particular, power flow studies cannot be performed properly without this information. Then, depending upon the status of local available Generation, ISO and other Operations Engineers would be able to calculate Generating Unit Dispatch requirements and limitations that allow the utility to perform the requested transmission work reliably. Therefore, to maintain reliable operations when scheduling this transmission work, the ISO and the other Outage Coordinators and Operations Engineers must be able to share the same understanding of applicable Generating Unit Outages. Such information sharing will enable the ISO and other Operations Engineers to conduct clearance studies using the same information, thereby reaching

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[17] *I.e.*, correcting the outage requires attention to both transmission components under the control of the ISO and other network components, such as generator ties or feeds to single customer substations, under the control of the Participating TOs or other operating entities.

common, accurate results when calculating and specifying Generating Unit requirements, transmission monitoring points, and required operator actions.[18]

For those systems in which constraints exist, the ISO faces significant hurdles in balancing Generation and transmission work, especially because the ISO may not have specific, "up-to-the-minute" construction work plans until shortly before the "specific" construction activity commences. In particular, many constraints depend on whether a specific Generating Unit is on- or off-line. For example, in connection with a particular clearance, a Participating TO may need to change the protective relay settings for higher or lower fault current. The fault current depends on which units are on- or off-line. Under these circumstances, a Participating TO **must** know whether a specific Generating Unit is on- or off-line that day because the proper protective relay settings depend on such information. Failure to establish the proper relay settings could lead to relay mis-operation, which could lead to equipment damage, undesired relay action and even the loss of load.

Thus, the nature of Outage coordination work necessitates that the ISO share selected Generating Unit Outage information with other system operators. The ISO operates under conflicting "obligations" in these circumstances, however. On one hand, Section 20.3.2(e) of the ISO Tariff provides that the ISO shall treat Generating Unit Outage programs as confidential.[19] On the other hand, the ISO has an ongoing responsibility to ensure that transmission maintenance and construction work needed to keep the grid in service can be performed without undue service disruptions and within applicable operating reliability criteria. For example, Section 2.3.1.1.3(d) of the ISO Tariff provides that the ISO can "take any action it considers to be necessary consistent with Good Utility Practice to protect against uncontrolled loss of Load or Generation and/or equipment damage resulting from unforeseen circumstances." In performing its core function, the ISO must anticipate potential operational problems and take all such prudent actions as are necessary to prevent such operational problems from arising.

The ISO also notes that Participating TOs and some Generators within the ISO Control Area have operating agreements that require the Generator to share outage information with the Participating TO. Indeed, the ISO is a signatory party to many of these agreements. The inclusion of such

[18] There are even extreme cases where conflicting Generator and transmission Outages are immovable; in these instances, the system operator needs to be aware of the conflict and take preparatory actions (such as the temporary installation of special Load-dropping schemes) to maintain reliability.

[19] Such programs are confidential unless the Generator changes the program and the change causes Congestion within the next month, in which case the ISO may publish the identify of the Generator.

provisions is evidence that the sharing of Generating Unit Outage-related information that will affect a particular Participating TO is crucial to facilitate reliable system operations. These contractual provisions often are not followed, however.

Without the ability to communicate Generating Unit Outage information, coordinating transmission clearances becomes a lengthy, iterative guessing game, with the entity seeking the transmission clearance randomly testing windows of availability to find instances where Generation and transmission clearances do not conflict. This not only makes for an inefficient Outage coordination process but, more importantly, it may jeopardize reliability by forcing the ISO to delay essential transmission construction and maintenance work.

2. Proposed Modification

To maintain a smooth, reliable flow of transmission work, ISO Operations Engineering and ISO Outage Coordination personnel must have the ability to share relevant Generating Unit Outage information with other system operators. There is no legitimate basis to prevent the ISO from sharing individual Generating Unit Outage information provided there is a means in place to ensure the other party maintains the confidentiality of the information. Indeed, as indicated above, some Participating TOs and Generators within the ISO Control Area already have operating agreements that require the Generator to share Outage information with the Participating TO. The ISO therefore proposes to provide Generating Unit Outage information only to those parties who have executed the Western Electricity Coordinating Council ("WECC") Confidentiality Agreement for Electric System Data. For convenience, that agreement is provided as Attachment I. Parties to that agreement are prohibited from sharing operating information with any merchant function within their organization. Further, in accordance with Order No. 889,[20] Operations Engineering personnel of the Participating TOs are required to maintain the confidentiality of such information and cannot share such information with the merchant function of their organizations.

3. Description of Proposed Tariff Changes

The ISO proposes to add a new paragraph (c) to Section 20.3.4 of the ISO Tariff to allow it to share relevant Generating Unit Outage information with the operations engineering and outage coordination departments of the Participating TOs, or other operating entities as needed, provided the other

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[20] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. and Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, FERC Stats. and Regs. ¶ 31,253 (1997), *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998) ("Order No. 889").

party has executed the WECC Confidentiality Agreement for Electric System Data, to ensure the critical ongoing transmission system and Outage coordination analyses can be performed accurately and consistently.

II. EFFECTIVE DATE

The ISO respectfully requests that the Commission approve all of these Tariff revisions within the regular 60-day schedule, to be effective May 30, 2003 as is consistent with the Commission's Rules of Practice and Procedure, 18 C.F.R. § 35.3 (2002).

III. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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IV. SERVICE

The ISO has served copies of this letter, and all attachments, on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and on all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO's Home Page.

V. ATTACHMENTS

The following documents, in addition to this letter, support this filing:

Attachment A	Revised Tariff Sheets for Intra-Zonal Congestion Management
Attachment B	Black-lined Tariff provisions for Intra-Zonal Congestion Management
Attachment C	Revised Tariff Sheets for sharing Generator Outage information with other system operators
Attachment D	Black-lined Tariff provisions showing the changes proposed to share Generator Outage information with other system operators
Attachment E	Affidavit of Jim McIntosh, Director of Grid Operations
Attachment F	Affidavit of Eric W. Hildebrandt, Manager of Market Investigations
Attachment G	Confidential Report Supporting Attachment F
Attachment H	MSC Comments
Attachment I	WECC Confidentiality Agreement for Electric System Data
Attachment J	Notice of this filing, suitable for publication in the Federal Register (also provided in electronic format).

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger.

Please feel free to contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

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Enclosures

ATTACHMENT A

(e) reduce or eliminate Inter-Zonal Congestion based on Adjustment Bids and in accordance with the Congestion Management procedures, and Intra-Zonal Congestion in accordance with Section 7.2.6; and

(f) if necessary, make mandatory adjustments to Schedules in accordance with the Congestion Management procedures.

2.2.3 Scheduling Coordinator Certification.

The ISO shall accept Schedules and bids for Energy and Ancillary Services only from Scheduling Coordinators which it has certified in accordance with Section 2.2.4 as having met the requirements of this Section 2.2.3. Scheduling Coordinators scheduling Ancillary Services shall additionally meet the requirements of Section 2.5.6.

2.2.3.1 Each Scheduling Coordinator shall:

(a) demonstrate to the ISO's reasonable satisfaction that it is capable of performing the functions of a Scheduling Coordinator under this ISO Tariff including (without limitation) the functions specified in Sections 2.2.6 and 2.2.7 and that it is capable of complying with the requirements of all ISO Protocols;

(b) identify each of the Eligible Customers (including itself if it trades for its own account) which it is authorized to represent as Scheduling Coordinator and confirm that the metering requirements under Section 10 are met in relation to each Eligible Customer for which it is submitting bids under this ISO Tariff;

(c) confirm that each of the End-Use Customers it represents is eligible for Direct Access;

(d) confirm that none of the Wholesale Customers it represents is ineligible for wholesale transmission service pursuant to the provisions of FPA Section 212(h);

changes to the Suggested Adjusted Schedules, all of the Suggested Adjusted Schedules shall become the Final Schedules. The Final Schedules shall serve as the basis for Settlement between the ISO and each Scheduling Coordinator.

2.2.9 [Not Used]

2.2.10 Information to be Provided by the ISO to all Scheduling Coordinfators.

By 6:00 p.m. two days prior to a Trading Day, the ISO shall publish on WEnet information, including the following to all Scheduling Coordinators for each Settlement Period of the Trading Day:

2.2.10.1 Scheduled Line Outages. Scheduled transmission line Outages;

2.2.10.2 [Not Used]

2.2.10.3 Forecast Loop-Flow. Forecast Loop Flow over ISO Inter-zonal Interfaces and Scheduling Points;

2.2.10.4 Advisory Demand Forecasts. Advisory Demand Forecasts by location;

2.2.10.5 Updated Transmission Loss Factors. Updated Generation Meter Multipliers reflecting Transmission Losses to be supplied by each Generating Unit and by each import into the ISO Control Area;

2.2.10.6 Ancillary Services. Expected Ancillary Services requirement by reference to Zones for each of the reserve Ancillary Services; and

2.2.10.7 Advisory Intra-Zonal Congestion Scheduling Limits. To the Scheduling Coordinator for such affected Generating Units, the hourly maximum or minimum total allowable output for a Generating Unit or group of Generating Units constrained by the same Intra-Zonal interface that the ISO forecasts to be Congested due to de-rated transmission facilities, transmission outages, or other abnormal network configurations.

2.2.10.8 [Not Used]

2.2.12.3 **Non-PX Demand Information.** By 6:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator (other than the PX) shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

2.2.12.4 The Preferred Schedule of each Scheduling Coordinator for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day together with any Adjustment Bids and Ancillary Services bids.

2.2.12.5 In submitting its Preferred Schedule, each Scheduling Coordinator shall notify the ISO of any Dispatchable Loads which are not scheduled but have submitted Adjustment Bids and are available for Dispatch at those same Adjustment Bids to assist in relieving Congestion.

2.2.12.6 **ISO Analysis of Preferred Schedules.** On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR SCs to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned

7.2.1.4 Elimination of Potential Transmission Congestion. The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Inter-Zonal Congestion by:

7.2.1.4.1 scheduling the use of Inter-Zonal Interfaces by the Scheduling Coordinators who place the highest value on those rights, based on the Adjustment Bids that are submitted by Scheduling Coordinators; and

7.2.1.4.2 rescheduling Scheduling Coordinators' resources (but so that Intra-Zonal transmission limits are not violated) using the Adjustment Bids that are submitted by Scheduling Coordinators.

7.2.1.5 Elimination of Real Time Inter-Zonal Congestion. In its management of Inter-Zonal Congestion in real time, the ISO will make the minimum amount of adjustment necessary to relieve Inter-Zonal Congestion by incrementing or decrementing Generation or Demand, as necessary, based on the merit order stack, in accordance with Dispatch Protocol Section 8.3.

7.2.2 General Requirements for the ISO's Congestion Management. The ISO's Congestion Management in the Day-Ahead Market and Hour-Ahead Market shall:

7.2.2.1 only operate if the Scheduling Coordinators do not eliminate Congestion voluntarily;

7.2.2.2 adjust the Schedules submitted by Scheduling Coordinators only as necessary to alleviate Congestion;

7.2.2.3 maintain separation between the resource portfolios of different Scheduling Coordinators, by not arranging any trades between Scheduling Coordinators as part of the Inter-Zonal Congestion Management process;

7.2.4.1.2 The Adjustment Bids will be used by the ISO to determine the marginal value associated with each Congested Inter-Zonal Interface.

7.2.4.1.3 [Not used]

7.2.4.1.4 The ISO shall also use the Adjustment Bids from System Resources and Dispatchable Loads in the ISO's real time system operation for Intra-Zonal Congestion Management and to decrement Generation in order to accommodate Overgeneration conditions, including Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts.

7.2.4.1.5 To facilitate trades amongst Scheduling Coordinators, the ISO will develop procedures to publish Adjustment Bids of those Scheduling Coordinators who authorize the publication of their identity and/or Adjustment Bids. Scheduling Coordinators will then be able to utilize this information to conduct trades to aid Congestion Management.

7.2.4.2 Submission of Adjustment Bids.

7.2.4.2.1 Each Scheduling Coordinator is required to submit a preferred operating point for each of its resources. However, a Scheduling Coordinator is not required to submit an Adjustment Bid for a resource.

7.2.4.2.2 The minimum MW output level specified for a resource, which may be zero MW, and the maximum MW output level specified for a resource must be physically realizable by the resource.

7.2.4.2.3 The Scheduling Coordinator's preferred operating point for each resource must be within the range of the Adjustment Bids.

7.2.4.2.4 Adjustment Bids can be revised by Scheduling Coordinators after the Day-Ahead Market has closed for consideration in the Hour-Ahead Market and, after the Hour-

7.2.5.2.7 If inadequate Adjustment Bids have been submitted to schedule Inter-Zonal Interface capacity on an economic basis and to the extent that scheduling decisions cannot be made on the basis of economic value, the ISO will allocate the available Inter-Zonal Interface capacity to Scheduling Coordinators in proportion to their respective proposed use of that capacity as indicated in their Schedules and shall curtail scheduled Generation and Demand to the extent necessary to ensure that each Scheduling Coordinator's Schedule remains balanced.

7.2.5.2.8 The ISO will publish information prior to the Day-Ahead Market, between the iterations of the Day-Ahead Market, and prior to the Hour-Ahead Market, to assist the Scheduling Coordinators to construct their Adjustment Bids so as to actively participate in the management of Congestion and the valuation of Inter-Zonal Interfaces. This information may include the ISO's most-current information regarding: potentially Congested paths, projected transmission uses, projected hourly Loop Flows across Inter-Zonal Interfaces, scheduled line Outages, forecasts of expected system-wide Load, the ISO's Ancillary Services requirements, Generation Meter Multipliers, and power flow outputs.

7.2.5.2.8 The ISO will also publish information, once it is available, regarding tentative prices for the use of Inter-Zonal Interfaces, and Generation shift factors for the use of Inter-Zonal Interfaces, which indicate the relative effectiveness of Generation shifts in alleviating Congestion.

7.2.6 Intra-Zonal Congestion Management.

7.2.6.1 Intra-Zonal Congestion Management. If Final Hour-Ahead Schedules cause Congestion on the Intra-Zonal interface, the ISO shall, after Dispatching available and effective Reliability Must-Run Units to manage the Congestion, create proxy Energy bids and Dispatch Generating Units according to those bids based on the proxy Energy bid cost, the resource's effectiveness on the Congestion, and other relevant factors such as Energy limitations, existing contractual restrictions, and Regulatory Must-Run or Regulatory Must-Take status, to alleviate the Congestion after Final Hour-Ahead Schedules are issued. The ISO shall Dispatch Generating Units according to proxy Energy bids and not according to Adjustment Bids or Supplemental Energy Bids to alleviate Intra-Zonal Congestion. No Generating Unit shall be Dispatched below its minimum operating level or above its maximum operating level. No Reliability Must-Run Unit shall be Dispatched below the operating level determined by the ISO as necessary to maintain reliability. If Congestion still exists after all Generating Units are Dispatched to their minimum operating levels, the ISO shall instruct Generating Units to shut off in merit order based on their proxy Energy cost at minimum load, beginning with the most expensive unit.

The ISO shall create the proxy Energy bids 1) for themal Generating Units, using the unit's incremental heat rate curve, the proxy cost for natural gas posted on the ISO Home Page, and a $6.00/MWh variable operations and maintenance adder, or 2) for non-thermal Generating Units, using the unit's reference price as determined in Appendix A to the Market Monitoring and Information Protocol.

If the ISO Dispatches System Resources or Dispatchable Loads to alleviate Intra-Zonal Congestion, the ISO shall Dispatch those resources in merit order according to the resource's Day-Ahead or Hour-Ahead Adjustment Bid or Imbalance Energy bid.

7.2.6.1.1 [Not used]

7.2.6.1.2 [Not Used]

7.2.6.1.3 [Not Used]

7.2.6.1.4 [Not Used]

7.2.6.1.5 [Not Used]

7.2.6.1.6 [Not Used]

7.2.6.2 Intra-Zonal Congestion During Initial Period. Except as provided in Sections 5.2 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management as provided in Section 7.2.6.

7.2.6.3 Cost of Intra-Zonal Congestion Management. The net of the amounts paid by the ISO to the Scheduling Coordinators and the amounts charged to the Scheduling Coordinators will be calculated and charged to all Scheduling Coordinators through a Grid Operations Charge, as described in Section 7.3.2.

7.2.7 Creation, Modification and Elimination of Zones.

7.2.7.1 Active Zones. The Active Zones are as set forth in Appendix I to this ISO Tariff.

7.2.7.2 Modifying Zones. The ISO shall monitor usage of the ISO Controlled Grid to determine whether new Zones should be created, or whether existing Zones should be eliminated, in accordance with the following procedures.

7.2.7.2.1 If over a 12-month period, the ISO finds that within a Zone the cost to alleviate the Congestion on a path is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average High Voltage Access Charge and Low

Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the ISO shall: (1) charge each Participating TO and Project Sponsor(s) as provided in Section 3.2.7.3, and FTR Holder with an amount equal to its proportionate share, based on its financial entitlement to Usage Charges in the Day-Ahead Market in accordance with Section 7.3.1.6, of the product of (i) the Usage Charge in the Day-Ahead Market and (ii) the reduction in Available Transfer Capacity across the Inter-Zonal Interface in the direction of the Congestion (such amount due to the Participating TOs to be debited by them in turn from their Transmission Revenue Balancing Accounts or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements); (2) charge each Scheduling Coordinator with its proportionate share, based on Schedules in the Day-Ahead Market across the Inter-Zonal Interface in the direction of the Congestion, of the difference between the amount charged to Participating TOs and Project Sponsors as provided in Section 3.2.7.3, and FTR Holders under clause (1) and the Usage Charges in the Hour-Ahead Market associated with the reduced Available Transfer Capacity across the Congested Inter-Zonal Interface; and (3) credit each Scheduling Coordinator whose Schedule in the Hour-Ahead Market for the transfer of Energy across the Congested Inter-Zonal Interface was adjusted due to the reduction in Available Transfer Capacity an amount equal to the product of the adjustment (in MW) and the Usage Charge in the Hour-Ahead Market (in$/MW).

The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.

7.3.2 Grid Operations Charge for Intra-Zonal Congestion.

Scheduling Coordinators whose resources are redispatched by the ISO, in accordance with Intra-Zonal Congestion Management as set forth in Section 7.2.6, will be paid or charged as set forth in Settlements and Billing Protocol Appendix B. The net

DP 8 REAL TIME OPERATIONAL ACTIVITIES – THE SETTLEMENT PERIOD

DP 8.1 Settlement Period

DP 8.1.1 Responsibility of the ISO in Real Time Dispatch

During real time Dispatch, the ISO will be responsible for dispatching Generating Units, Curtailable Demands and Interconnection schedules to meet real time imbalances between actual and scheduled Demand and Generation and to relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria.

DP 8.1.2 Utilization of BEEP

To achieve this, the ISO Control Center will utilize the merit order stack of available resources prepared pursuant to the SP through BEEP.

DP 8.2 Generating Units, Loads and Interconnection Schedules Dispatched for Congestion

If there is Inter-Zonal Congestion in real time, the ISO will use the merit order stack produced by BEEP to alleviate Inter-Zonal Congestion as described in DP 8.3. The ISO will manage Intra-Zonal Congestion in real-time as set forth in Section 7.2.6.

DP 8.3 Inter-Zonal Congestion

DP 8.3.1 Treatment by Zone

If there is Inter-Zonal Congestion in real time, the ISO shall increase Generation and/or reduce Demand separately for each Zone.

DP 8.3.2 Selection of Generating Unit or Load to Increase Generation or Reduce Demand

Where the ISO determines that it is necessary to increase Generation or reduce Demand in a Zone in order to relieve Inter-Zonal Congestion the ISO shall select from the merit order stack the Generating Unit within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to increment which has the lowest incremental bid price ($/MWh) or the Curtailable Demand located within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to reduce which has the lowest Demand reduction bid price.

DP 8.3.3 Selection of Generating Unit to Reduce Generation

Where the ISO determines that it is necessary to reduce Generation in a Zone in order to relieve Inter-Zonal Congestion, the ISO shall select from the merit order stack the Generating Unit within the Zone with a non-zero capacity remaining to decrement which has the highest decremental bid price.

DP 8.4 Intra-Zonal Congestion

Except as provided in Section 5.2 of the ISO Tariff, in the event of Intra-Zonal Congestion, the ISO shall adjust Generating Units and Curtailable Demands (or Interconnection schedules of System Resources in the Control Areas) to alleviate the constraints as described in Section 7.2.6.

DP 8.5 Additional Congestion Relief

In the event that there are insufficient resources which provide financial bids to mitigate Inter-Zonal and Intra-Zonal Congestion, Final Schedules which do not rely on Existing Contracts will be adjusted in real time by allocating transmission capacity on a pro rata basis. Final Schedules which rely on Existing Contracts will be adjusted in real time by allocating transmission capacity in accordance with the operating instructions submitted under SBP 3.3. With respect to facilities financed with Local Furnishing Bonds the ISO shall adjust Final Schedules in real time in a fashion consistent with Section 2.1.3 and 7.1.6.3 of the ISO Tariff, Appendix B of the TCA, and Operating Procedures governing the use of such facilities.

DP 8.6 Real Time Dispatch Application

DP 8.6.1 Real Time Dispatch

During real time, the ISO shall dispatch Generating Units, Curtailable Demands and Interconnection schedules to meet imbalances between actual and scheduled Demand and Generation.

In addition, the ISO may need to purchase additional Ancillary Services if Ancillary Services arranged in advance are used to provide balancing Energy, and such depletion needs to be recovered to meet System Reliability contingency requirements.

DP 8.6.2 Utilization of the Merit Order Stack

The ISO will use the merit order stack as produced by BEEP, consisting of all the Supplemental Energy and Ancillary Services Energy bids as described in the SP to procure balancing Energy for:

(a) satisfying needs for Imbalance Energy;

(b) mitigating Inter-Zonal Congestion;

(c) allowing resources providing Regulation service to return to the mid-point of their regulating ranges;

(d) allowing recovery of Operating Reserves utilized in real time operations;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads to manage Intra-Zonal Congestion in real time.

DP 8.6.3 Basis for Real Time Dispatch

The ISO shall base real time Dispatch of Generating Units, Curtailable Demands and Interconnection schedules on the following principles:

(a) the ISO shall dispatch Generating Units and dispatchable Interconnection schedules providing Regulation service to meet WSCC and NERC Area Control Error (ACE) performance criteria;

(b) in each BEEP Interval, following the loss of a resource and once ACE has returned to zero, the ISO shall determine if the Regulation Generating Units and dispatchable Interconnection schedules are operating at a point away from their Set Point. The ISO shall then adjust the output of Generating Units, Curtailable Demands, and dispatchable Interconnection schedules (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, or Supplemental Energy) to return the Regulation Generating Units and dispatchable Interconnection schedules to their Set Points to restore their full regulating margin;

(c) in each BEEP Interval, the ISO shall dispatch Generating Units, Curtailable Demands and dispatchable Interconnection schedules to meet its balancing Energy requirements and eliminate any Price Overlap between decremental and incremental Energy Bids, thereby, dispatching the relevant resources in real time for economic trades either between SCs or within a SC's portfolio;

(d) the ISO shall select the Generating Units, Curtailable Demands and dispatchable Interconnection schedules to be dispatched to meet its balancing Energy requirements based on the merit order stack of Energy bid prices produced by BEEP;

(e) the ISO shall not discriminate between Generating Units, Curtailable Demands and dispatchable Interconnection schedules other than based on price, and the effectiveness (location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation;

(f) Generating Units, Curtailable Demands or dispatchable Interconnection schedules shall be dispatched during the Settlement Period only until the next variation in Generation or Demand or the end of the Settlement Period, whichever is sooner. In dispatching such resources, the ISO is not making any commitment beyond the Settlement Period, as to the duration of their operation, nor the level of their output or Demand;

(g) The ISO will not differentiate between Ancillary Services procured by the ISO and Ancillary Services which are being self-provided;

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific Time.

SBP 1.3 Scope

SBP 1.3.1 Scope of Application to Parties

The SBP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Participating Transmission Owners (PTOs); and

(c) the Independent System Operator (ISO).

SBP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SBP 2 SCHEDULES AND NOTIFICATIONS

SBP 2.1 Contents of Schedules and Adjustment Bid Data

SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Schedules and bid. Except as noted, each of the following data sections can be submitted up to seven (7) days in advance.

SBP 2.1.1 Generation Section of a Balanced Schedule and Adjustment Bid Data

The Generation section of a Balanced Schedule will include the following information for each Generating Unit:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) name of Generating Unit scheduled;

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN) for Reliability Must-Run Generation;

(f) contract reference number for Reliability Must-Run Generation;

(g) Inter-Zonal Congestion Management flag – "Yes" indicates that any Adjustment Bid submitted under item (k) below should be used;

cannot be found in the ISO's scheduling applications table of contract reference numbers), the scheduled use will be invalidated and the SC notified by the ISO's issuance of an invalidated usage information template.

SBP 4 ADJUSTMENT BIDS

Adjustment Bids will be used by the ISO for Inter-Zonal Congestion Management as described in the SP and are initially valid only for the markets into which they are bid, being the Day-Ahead Market or the Hour-Ahead Market. These Adjustment Bids will not be transformed into Supplemental Energy bids. However, these Adjustment Bids are treated as standing offers to the ISO and may be used by the ISO in the Real Time Market for the purpose of managing Intra-Zonal Congestion using System Resources and Dispatchable Loads and for managing Overgeneration conditions.

SBP 4.1 Content of Adjustment Bids

Adjustment Bids are contained in Preferred Schedules and Revised Schedules submitted by SCs for particular Generating Units (including Physical Scheduling Plants), Dispatchable Loads, external imports/exports, and Generating Units and Dispatchable Loads supporting Inter-Scheduling Coordinator Energy Trades.

Each SC is required to submit a preferred operating point for each Generating Unit, Dispatchable Load and external import/export (these quantities are presented in the SC's submitted Schedule as "Hourly MWh"). The SC's preferred operating point for each Generating Unit, Dispatchable Load and external import/export must be within the range of any Adjustment Bids to be used by the ISO. The minimum MW output level, which may be zero MW (or negative for pumped storage resources), and the maximum MW output level must be physically achievable.

SBP 4.2 Format of Adjustment Bids

Adjustment Bids will be presented in the form of a monotonically non-decreasing staircase function for Generating Units and external imports. Adjustment Bids will be presented in the form of a monotonically non-increasing staircase function for Dispatchable Loads and external exports. These staircase functions will be composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information. Adjustment Bids are submitted as an integral part of the SC's Balanced Schedule and must be related to each Generating Unit, Dispatchable Load and external import/export. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Adjustment Bids.

Management software will assign high priced Adjustment Bids to the scheduled uses (for example, a difference of $130,000/MWh to $140,000/MWh for Demand or external exports and a difference of -$130,000/MWh to -$140,000/MWh for Generation or external imports). This range will be reserved strictly for use in association with the prioritization of firm Existing Rights to use available Inter-Zonal Interface transmission capacity. These high priced Adjustment Bids are only for the ISO's use, in the context of Inter-Zonal Congestion Management, in recognizing the various levels of priority that may exist among the scheduled uses of firm transmission service. These high priced Adjustment Bids will not affect any other rights under Existing Contracts. To the extent that the MW amount exceeds the MW amount specified in the Existing Contract, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) below. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple SCs submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their firm uses of the Inter-Zonal Interface, their SCs will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a "price-taker" of ISO transmission service subject to Usage Charges.

(b) ISO transmission service (i.e., "new firm uses") will be priced in accordance with the ISO Tariff. Usage Charges associated with the ISO's Congestion Management procedures, as described in SP 10, will be based on Adjustment Bids. In the absence of an Adjustment Bid, the ISO will treat the scheduled "new firm use" of ISO transmission service as a price taker paying the Usage Charge established by the highest valued use of transmission capacity between the relevant Zones.

(c) Transmission capacity will be made available to holders of conditional firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, allocated, as available, based on the agreed priority. The levels of priority will be expressed in the contract usage templates associated with the Schedules. To the extent that the MW amount in a schedule exceeds the MW amount specified in the contract usage template, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) above. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple SCs submitting Schedules under several arrangements or its Transmission Owner's Tariff. The ISO will not undertake the settlement or billing of any such differences under any Existing Contract.

SP 10 DAY/HOUR-AHEAD INTER-ZONAL CONGESTION MANAGEMENT

SP 10.1 Congestion Management Assumptions

The Inter-Zonal Congestion Management process is based upon the following assumptions:

(a) Inter-Zonal Congestion Management will ignore Intra-Zonal Congestion. Intra-Zonal Congestion will be managed in accordance with Tariff Sections 2.2.10.7 and 7.2.6;

(b) Inter-Zonal Congestion Management will use a DC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only; and

(c) transmission capacity reserved under Existing Contracts will not be subject to the ISO's Congestion Management procedures.

SP 10.2 Congestion Management Process

(a) Inter-Zonal Congestion Management will involve adjusting Schedules to remove potential violations of Inter-Zonal Interface constraints, minimizing the redispatch cost, as determined by the submitted Adjustment Bids that accompany the submitted Schedules. See the SBP for a general description of the use of Adjustment Bids to establish priorities.

(b) Inter-Zonal Congestion Management will not involve arranging or modifying trades between SCs. Each SC's portfolio will be kept in balance (i.e., its Generation plus external imports, as adjusted for Transmission Losses, and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) will still match its Demand plus external exports) after the adjustments. Market Participants will have the opportunity to trade with one another and to revise their Schedules during the first Congestion Management iteration in the Day-Ahead Market, and between the Day-Ahead Market and Hour-Ahead Market.

(c) Inter-Zonal Congestion Management will also not involve the optimization of SC portfolios within Zones (where such apparently non-optimal Schedules are submitted by SCs). Adjustments to individual SC portfolios within a Zone will be either incremental (i.e., an increase in Generation and external imports and a decrease in Demand and external exports) or decremental (i.e., a decrease in Generation and external imports and an increase in Demand and external exports), but not both.

(d) If Adjustment Bids are exhausted before Congestion is eliminated, the remaining Schedules will be adjusted *pro rata* except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with SP 7.3 and SP 7.4.

SP 10.3 Congestion Management Pricing

(a) The Adjustment Bids that the SCs submit constitute implicit bids for transmission between Zones on either side of a Congested Inter-Zonal Interface. The ISO's Inter-Zonal

Where, in any BEEP Interval, the highest decremental Energy Bid in the merit order stack is higher than the lowest incremental Energy Bid, the BEEP Software will eliminate the Price Overlap by actually dispatching for all those incremental and decremental bids which fall within the overlap.

References to incremental Energy Bids include references to Demand reduction bids, and for the purpose of applying this algorithm a reduction in Demand shall be treated as an equivalent increase in Generation.

SP 11.3 Use of the Merit Order Stack

The merit order stack, as described in SP 11.2, can be used to supply Energy for:

(a) satisfying needs for Imbalance Energy (differences between actual and scheduled Generation, Demand and external imports/exports) in real time;

(b) managing Inter-Zonal Congestion in real time;

(c) supplying Energy necessary to allow resources providing Regulation service to return to the base point of their regulating ranges in real time;

(d) recovering Operating Reserves utilized in real time;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads to manage Intra-Zonal Congestion in real time.

SP 12 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

APPENDIX B

GRID OPERATIONS CHARGE COMPUTATION

B 1 Purpose of charge

The Grid Operations Charge is a charge which recovers redispatch costs incurred due to Intra-Zonal Congestion pursuant to Section 7.3.2 of the ISO Tariff. The Grid Operations Charge is paid by or charged to Scheduling Coordinators in order for the ISO to recover and properly redistribute the costs of adjusting the Balanced Schedules submitted by Scheduling Coordinators.

B 2 Fundamental formulae

B 2.1 Payments to SCs with incremented schedules

When it becomes necessary for the ISO to increase the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ or reduce a Curtailable Demand$_i$ in order to relieve Congestion within a Zone, the ISO will pay the Scheduling Coordinator. The amount that ISO pays the Scheduling Coordinator$_j$ for increasing the output of Generating Unit$_i$ is the greater of (1) 1.1 times the price specified in the Scheduling Coordinator's proxy energy bid as determined in accordance with Section 7.2.6.1 or (2) the relevant BEEP Interval Ex Post Price multiplied by the quantity of Energy Dispatched. The amount ISO pays the Scheduling Coordinator$_j$ for increasing the output of a System Resource$_i$ or Curtailable Demand$_i$ is the price specified in the Scheduling Coordinator's Day-Ahead or Hour-Ahead Adjustment Bid (or Imbalance Energy bid as appropriate) multiplied by the quantity of Energy Dispatched. The formula for calculating the payment to Scheduling Coordinator$_j$ for each block$_b$ of Energy of its Adjustment Bid curve in Trading Interval$_t$ is:

$$INC_{bijt} = adjinc_{bijt} * \Delta inc_{bijt}$$

B 2.1.1 Total Payment for Trading Interval

The formula for calculating payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been increased or Curtailable Demand$_i$ reduced for all the relevant blocks$_b$ of Energy in the applicable proxy energy bid curve, Adjustment Bid curve, or Imbalance Energy bid of that Generating Unit or System Resource or Curtailable Demand in the same Trading Interval$_t$ is:

$$PayTI_{ijt} = \sum_b INC_{bijt}$$

B 2.2 Charges to Scheduling Coordinators with decremented schedules

When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ in order to relieve Congestion within a Zone, the ISO will make a charge to the Scheduling Coordinator. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of Generating Unit$_i$ is the lesser of (1) 0.9 times the price specified in the Scheduling Coordinator's proxy energy bid as determined in accordance with Section 7.2.6.1 or (2) the relevant BEEP Interval Ex Post Price multiplied by the quantity of Energy Dispatched. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of a System Resource$_i$ is the price specified in the Scheduling Coordinator's Day-Ahead or Hour-Ahead Adjustment Bid (or Imbalance Energy Bid as appropriate) multiplied by the quantity of Energy Dispatched. The formula for calculating the charge to Scheduling Coordinator$_j$ for each block$_b$ of Energy in its applicable proxy energy bid curve, Adjustment Bid curve, or Imbalance Energy bid in Trading Interval$_t$ is:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

B 2.2.1 Total Charge for Trading Interval

The formula for calculating the charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been decreased for all the relevant blocks$_b$ of Energy in the applicable proxy energy bid curve, Adjustment Bid curve, or Imbalance Energy bid of that Generating Unit or System Resource in the same Trading Interval$_t$ is:

$$ChargeTI_{ijt} = \sum_b DEC_{bijt}$$

B 2.3 Not Used

B 2.4 Net ISO redispatch costs

The Trading Interval net redispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Curtailable Demand was decreased during the Trading Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System Resource were decreased during the Trading Interval. The fundamental formula for calculating the net redispatch cost is:

$$REDISP_{CONGt} = \sum_i PayTI_{ijt} - \sum_i ChargeTI_{ijt}$$

Note that $REDISP_{CONGt}$ can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Trading Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net redispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Curtailable Demand was decreased (or increased) during the Trading Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.

B 2.5 Grid Operations Price

The grid operations price is the Trading Interval rate used by the ISO to apportion net Trading Interval redispatch costs to Scheduling Coordinators within the Zone with Intra-Zonal Congestion. The grid operations price is calculated using the following formula:

$$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

B 2.6 Grid Operations Charge

The Grid Operations Charge is the vehicle by which the ISO recovers the net redispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and Exports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator$_j$ in Trading Interval$_t$ is:

$$GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)$$

B 3 Meaning of terms of formulae

B 3.1 INC_{bijt} - $

The payment from the ISO due to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is increased or Curtailable Load$_i$ is reduced within a block$_b$ of Energy in the applicable proxy energy bid curve, Adjustment Bid curve, or Imbalance Energy bid in Trading Interval$_t$ in order to relieve Intra-Zonal Congestion.

B 3.2 $adjinc_{bijt}$ - $/MWh

The incremental cost for the rescheduled Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ taken from the relevant block$_b$ of Energy in the applicable proxy energy bid curve, Day-Ahead or Hour-Ahead Adjustment Bid curve, or Imbalance Energy bid submitted by the Scheduling Coordinator$_j$ or generated by the ISO for the Trading Interval$_t$.

B 3.3 Δincbijt - MW

The amount by which the Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ of Scheduling Coordinator$_j$ for Trading Interval$_t$ is increased by the ISO within the relevant block$_b$ of Energy in its applicable proxy energy bid curve, Adjustment Bid curve, or Imbalance Energy bid.

B 3.4 $PayTI_{jit}$ - $

The Trading Interval payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ has been increased or System Resource$_i$ or Curtailable Load$_i$ reduced in Trading Interval$_t$ of the Trading Day.

B 3.5 DEC_{bijt} - $

The charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is decreased for Trading Interval$_t$ within a block$_b$ of Energy in its applicable proxy energy bid curve, Adjustment Bid curve, or Imbalance Energy bid.

B 3.6 $adjdec_{bijt}$ - \$/MWh

The decremental cost for the rescheduled Generating $Unit_i$ or System $Resource_i$ taken from the relevant $block_b$ of Energy of the applicable proxy energy bid curve, Day-Ahead or Hour-Ahead Adjustment Bid curve, or Imbalance Energy bid submitted by Scheduling $Coordinator_j$ or generated by the ISO for the Trading $Interval_t$.

B 3.7 Δdec_{bijt} - MW

The amount by which the Generating $Unit_i$ or System $Resource_i$ of Scheduling $Coordinator_j$ for Trading $Interval_t$ is decreased by ISO within the relevant $block_b$ of Energy of its applicable proxy energy bid curve, Adjustment Bid curve, or Imbalance Energy bid.

B 3.8 $ChargeTI_{ijt}$ - \$

The Trading Interval charge to Scheduling $Coordinator_j$ whose Generating $Unit_i$ or System $Resource_i$ has been decreased in Trading $Interval_t$ of the Trading Day.

B 3.9 Not Used

B 3.10 Not Used

B 3.10.1 Not Used

B 3.10.2 P_{xt} - \$/MWh

The zonal Hourly Ex Post Price, for Uninstructed Imbalance Energy, for Trading Interval t in Zone x.

B 3.11 $REDISP_{CONGt}$ - \$

The Trading Interval net cost to ISO to redispatch in order to relieve Intra-Zonal Congestion during Trading $Interval_t$.

B 3.12 GOP_t - \$/MWh

The Trading Interval grid operations price for Trading $Interval_t$ used by the ISO to recover the costs of redispatch for Intra-Zonal Congestion Management.

B 3.13 GOC_{jt} - \$

The Trading Interval Grid Operations Charge by the ISO for Trading $Interval_t$ for Scheduling $Coordinator_j$ in the relevant Zone with Intra-Zonal Congestion.

B 3.14 $QCHARGE_{jt}$ – MWh

The Trading Interval metered Demand within a Zone for Trading $Interval_t$ for Scheduling $Coordinator_j$ whose Grid Operations Charge is being calculated.

B 3.15 $EXPORT_{jt}$ – MWh

The total Energy for Trading $Interval_t$ exported from the Zone to a neighboring Control Area by Scheduling $Coordinator_j$.

ATTACHMENT B

2.2.2 ISO Scheduling Responsibilities.

To fulfill its obligations with respect to scheduling Energy and Ancillary Services, the ISO shall:

(a) provide Scheduling Coordinators with operating information and system status on a Day-Ahead and Hour-Ahead, Zonal and/or Scheduling Point basis to enable Scheduling Coordinators to optimize Generation, Demand and the provision of Ancillary Services;

(b) determine whether Preferred Schedules submitted by Scheduling Coordinators meet the requirements of Section 2.2.7.2, and whether they will cause Congestion;

(c) prepare Suggested Adjusted Schedules on a Day-Ahead basis and Final Schedules on a Day-Ahead and Hour-Ahead basis;

(d) validate all Ancillary Services bids and self provided Ancillary Services;

(e) reduce or eliminate Inter-Zonal Congestion based on Adjustment Bids and in accordance with the Congestion Management procedures, and Intra-Zonal Congestion in accordance with Section 7.2.6; and

(f) if necessary, make mandatory adjustments to Schedules in accordance with the Congestion Management procedures.

***

2.2.10.6 **Ancillary Services.** Expected Ancillary Services requirement by reference to Zones for each of the reserve Ancillary Services~~.~~; and

2.2.10.7 ~~[Not used]~~ Advisory Intra-Zonal Congestion Scheduling Limits. To the Scheduling Coordinator for such affected Generating Units, the hourly maximum or minimum total allowable output for a Generating Unit or group of Generating Units constrained by the same Intra-Zonal interface that the ISO forecasts to be Congested due to de-rated transmission facilities, transmission outages, or other abnormal network configurations.

2.2.10.8 **[Not Used]**

* * *

2.2.12.5 In submitting its Preferred Schedule, each Scheduling Coordinator shall notify the ISO of any ~~Generating Units or~~ Dispatchable Loads which are not scheduled but have submitted Adjustment Bids and are available for Dispatch at those same Adjustment Bids to assist in relieving Congestion.

***

7.2.1.4 **Elimination of Potential Transmission Congestion.** The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Inter-Zonal Congestion by:

7.2.1.4.1 scheduling the use of Inter-Zonal Interfaces by the Scheduling Coordinators who place the highest value on those rights, based on the Adjustment Bids that are submitted by Scheduling Coordinators; and

7.2.1.4.2 rescheduling Scheduling Coordinators' resources (but so that Intra-Zonal transmission limits are not violated) using the Adjustment Bids that are submitted by Scheduling Coordinators.

***

7.2.4.1.4 The ISO shall also use the Adjustment Bids from System Resources and Dispatchable Loads~~(in addition to other resources),~~ in the ISO's real time system operation~~,~~ for Intra-Zonal Congestion Management and to decrement Generation in order to accommodate Overgeneration conditions, including Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts.

***

7.2.6 Intra-Zonal Congestion Management.

7.2.6.1 ~~**[Not used]**~~ **Intra-Zonal Congestion Management.** If Final Hour-Ahead Schedules cause Congestion on the Intra-Zonal interface, the ISO shall, after Dispatching available and effective Reliability Must-Run Units to manage the Congestion, create proxy Energy bids and

Dispatch Generating Units according to those bids based on the proxy Energy bid cost, the resource's effectiveness on the Congestion, and other relevant factors such as Energy limitations, existing contractual restrictions, and Regulatory Must-Run or Regulatory Must-Take status, to alleviate the Congestion after Final Hour-Ahead Schedules are issued. The ISO shall Dispatch Generating Units according to proxy Energy bids and not according to Adjustment Bids or Supplemental Energy Bids to alleviate Intra-Zonal Congestion. No Generating Unit shall be Dispatched below its minimum operating level or above its maximum operating level. No Reliability Must-Run Unit shall be Dispatched below the operating level determined by the ISO as necessary to maintain reliability. If Congestion still exists after all Generating Units are Dispatched to their minimum operating levels, the ISO shall instruct Generating Units to shut off in merit order based on their proxy Energy cost at minimum load, beginning with the most expensive unit.

The ISO shall create the proxy Energy bids 1) for thermal Generating Units, using the unit's incremental heat rate curve, the proxy cost for natural gas posted on the ISO Home Page, and a $6.00/MWh variable operations and maintenance adder, or 2) for non-thermal Generating Units, using the unit's reference price as determined in Appendix A to the Market Monitoring and Information Protocol.

If the ISO Dispatches System Resources or Dispatchable Loads to alleviate Intra-Zonal Congestion, the ISO shall Dispatch those resources in merit order according to the resource's Day-Ahead or Hour-Ahead Adjustment Bid or Imbalance Energy bid.

***

7.2.6.2 Intra-Zonal Congestion During Initial Period. Except as provided in Sections 5.2 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management as provided in Section 7.2.6. ~~in real time using available Adjustment Bids and Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion. In the event no Adjustment Bids or Imbalance Energy bids are available, the ISO will exercise its authority to direct the redispatch of resources as allowed under the Tariff, including Section 2.4.2 and 2.4.4.~~

***

7.3.2 Grid Operations Charge for Intra-Zonal Congestion.

Scheduling Coordinators whose resources are redispatched by the ISO, in accordance with Intra-Zonal Congestion Management as set forth in Section 7.2.6, will be paid or charged as set forth in Settlements and Billing Protocol Appendix B~~based on the Adjustment Bids or Imbalance Energy bids that they have provided to the ISO~~. The net redispatch cost will be recovered for each Settlement Period through the Grid Operations Charge, which shall be paid to the ISO by all Scheduling Coordinators in proportion to their metered Demands within the Zone with Intra-Zonal Congestion, and scheduled exports from the Zone with Intra-Zonal Congestion to a neighboring Control Area, provided that, with respect to Demands within an MSS in the Zone and scheduled exports from the MSS to a neighboring Control Area, a Scheduling Coordinator shall be required to pay Grid Operations Charges only with respect to Intra-Zonal Congestion, if any, that occurs on an interconnection between the MSS and the ISO Controlled Grid, and with respect to Intra-Zonal Congestion that occurs within the MSS, to the extent the Congestion is not relieved by the MSS Operator.

***

DISPATCH PROTOCOL (DP)

DP 8.2 Generating Units, Loads and Interconnection Schedules Dispatched for Congestion

If there is Inter-Zonal ~~or Intra-Zonal~~ Congestion in real time, the ISO will use the merit order stack produced by BEEP to alleviate Inter-Zonal Congestion as described in DP 8.3. The ISO will manage Intra-Zonal Congestion in real-time as set forth in Section 7.2.6. ~~The ISO will use any Adjustment Bids which have been carried forward from the Day-Ahead or Hour-Ahead Markets as described in SBP 4, to resolve Intra-Zonal Congestion as described in DP 8.4.~~

***

DP 8.4 Intra-Zonal Congestion

Except as provided in Section 5.2 of the ISO Tariff, in the event of Intra-Zonal Congestion ~~in real time~~, the ISO shall adjust Generating Units and Curtailable Demands (or Interconnection schedules of System Resources in the Control Areas) to alleviate the constraints~~, using available Adjustment Bids and~~

~~Imbalance Energy bids based on their effectiveness and in merit order~~ as described in Section 7.2.6.

***

DP 8.6.2 Utilization of the Merit Order Stack

The ISO will use the merit order stack as produced by BEEP, consisting of all the Supplemental Energy and Ancillary Services Energy bids as described in the SP to procure balancing Energy for:

(a) satisfying needs for Imbalance Energy;

(b) mitigating Inter-Zonal Congestion;

(c) allowing resources providing Regulation service to return to the mid-point of their regulating ranges;

(d) allowing recovery of Operating Reserves utilized in real time operations;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads to manage~~ing~~ Intra-Zonal Congestion in real time.~~ after use of available Adjustment Bids.~~

***

SCHEDULES AND BIDS PROTOCOL (SBP)

SBP 2.1.1 Generation Section of a Balanced Schedule and Adjustment Bid Data

The Generation section of a Balanced Schedule will include the following information for each Generating Unit:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) name of Generating Unit scheduled;

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN) for Reliability Must-Run Generation;

(f) contract reference number for Reliability Must-Run Generation;

(g) Inter-Zonal Congestion Management flag – "Yes" indicates that any Adjustment Bid submitted under item (k) below should be used;

(h) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the SC wishes the ISO to publish its Adjustment Bids;

(i) Generating Unit ramp rate in MW/minute;

(j) hourly scheduled Generating Unit output in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule); and

(k) the MW and \$/MWh values for each Generating Unit for which an Adjustment Bid is being submitted consistent with SBP 4.

***

SBP 4 Adjustment Bids

Adjustment Bids will be used by the ISO for **<u>Inter-Zonal</u>** Congestion Management as described in the SP and are initially valid only for the markets into which they are bid, being the Day-Ahead Market or the Hour-Ahead Market. These Adjustment Bids will <u>not</u> be transformed into Supplemental Energy bids. However, these Adjustment Bids are treated as standing offers to the ISO and may be used by the ISO in the Real Time Market for the purpose of managing Intra-Zonal Congestion <u>using System Resources and Dispatchable Loads</u> and <u>for managing</u> Overgeneration conditions.

***

SCHEDULING PROTOCOL (SP)

SP 7.2.2 Prioritization of Transmission Uses

The following rules are designed to enable the ISO to honor Existing Contracts in accordance with Sections 2.4.3 and 2.4.4 of the ISO Tariff. Regardless of the success of the application of such rules, it is intended that the rights under Existing Contracts will be honored as contemplated by the ISO Tariff. In each of the categories described in SP 7.2.1, the terms and conditions of service may differ among transmission contracts. These differences will be described by each Responsible PTO in the instructions submitted to the ISO in advance of the scheduling process in accordance with the SBP. In addition, Generation, Inter-Scheduling Coordinator Energy Trade imports or external imports in one Zone must be matched by an equal magnitude of Demand, Inter-Scheduling Coordinator Energy Trade exports or external exports in an adjacent Zone (see SP 7.2.3 for a summary of allowable linkages). Scheduling and curtailment priorities associated with each category will be defined by SCs through the use of contract usage templates submitted as part of their Schedules as described in the SBP.

(a) Transmission capacity for Schedules will be made available to holders of firm Existing Rights in accordance with this SP and the terms and conditions of their Existing Contracts. In the event that the firm uses of these rights must be curtailed, they will be curtailed on the basis of priority expressed in contract usage templates. So as not to be curtailed before any other scheduled use of Congested Inter-Zonal Interface capacity, the ISO's Congestion Management software will assign high priced Adjustment Bids to the scheduled uses (for example, a difference of \$130,000/MWh to \$140,000/MWh for Demand or external exports and a difference of -\$130,000/MWh to -\$140,000/MWh for Generation or external imports). This range will be reserved strictly for use in association with the prioritization of firm Existing Rights to use available Inter-Zonal Interface transmission capacity. These high priced Adjustment Bids are only for the ISO's use, in the context of <u>Inter-Zonal</u> Congestion Management, in recognizing the various levels of priority that may exist among the scheduled uses of firm transmission service. These high priced Adjustment Bids will not affect any other rights under Existing Contracts. To the extent that the MW amount exceeds the MW amount specified in the Existing Contract, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) below. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple SCs submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their firm uses of the Inter-Zonal Interface, their SCs will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a "price-taker" of ISO transmission service subject to Usage Charges.

***

Day/Hour-Ahead Inter-Zonal Congestion Management

SP 10.1 Congestion Management Assumptions

The Inter-Zonal Congestion Management process is based upon the following assumptions:

(a) Inter-Zonal Congestion Management will ignore Intra-Zonal Congestion. Intra-Zonal Congestion will be managed in accordance with Tariff Sections 2.2.10.7 and 7.2.6~~real time~~;

(b) Inter-Zonal Congestion Management will use a DC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only; and

(c) transmission capacity reserved under Existing Contracts will not be subject to the ISO's Congestion Management procedures.

***

SP 11.3 Use of the Merit Order Stack

The merit order stack, as described in SP 11.2, can be used to supply Energy for:

(a) satisfying needs for Imbalance Energy (differences between actual and scheduled Generation, Demand and external imports/exports) in real time;

(b) managing Inter-Zonal Congestion in real time;

(c) supplying Energy necessary to allow resources providing Regulation service to return to the base point of their regulating ranges in real time;

(d) recovering Operating Reserves utilized in real time;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads to manage~~ing~~ Intra-Zonal Congestion in real time~~ after use of available Adjustment Bids~~.

SETTLEMENT AND BILLING PROTOCOL

APPENDIX B

GRID OPERATIONS CHARGE COMPUTATION

B 1 Purpose of charge

The Grid Operations Charge is a charge which recovers redispatch costs incurred due to Intra-Zonal Congestion pursuant to Section 7.3.2 of the ISO Tariff. The Grid Operations Charge is paid by or charged to Scheduling Coordinators in order for the ISO to recover and properly redistribute the costs of adjusting the Balanced Schedules submitted by Scheduling Coordinators.

B 2 Fundamental formulae

B 2.1 Payments to SCs with incremented schedules

When it becomes necessary for the ISO to increase the output of a Scheduling Coordinator's Generating $Unit_i$ or System $Resource_i$ or reduce a Curtailable $Demand_i$ in order to relieve Congestion within a Zone, the ISO will pay the Scheduling Coordinator. The amount that ISO pays the Scheduling $Coordinator_j$ for increasing the output of Generating $Unit_i$ is the greater of (1) 1.1 times the price specified in the Scheduling Coordinator's ~~Day-Ahead or Hour-Ahead~~ proxy energy~~Adjustment~~ b~~B~~id as determined in accordance with Section 7.2.6.1 or (2) the relevant BEEP Interval Ex Post Price multiplied by the quantity of Energy Dispatched.~~(or Imbalance Energy bid as appropriate) for the Generating Unit~~~~$_i$~~ ~~or~~ The amount that ISO pays the Scheduling $Coordinator_j$ for increasing the output of a System $Resource_i$ or Curtailable $Demand_i$ is the price specified in the Scheduling Coordinator's Day-Ahead or Hour-Ahead Adjustment Bid (or Imbalance Energy bid as appropriate) multiplied by the quantity of Energy Dispatched~~rescheduled~~. The formula for calculating the payment to Scheduling $Coordinator_j$ for each $block_b$ of Energy of its Adjustment Bid curve in Trading $Interval_t$ is:

$$INC_{bijt} = adjinc_{bijt} * \Delta inc_{bijt}$$

B 2.1.1 Total Payment for Trading Interval

The formula for calculating payment to Scheduling $Coordinator_j$ whose Generating $Unit_i$ or System $Resource_i$ has been increased or Curtailable $Demand_i$ reduced for all the relevant $blocks_b$ of Energy in the applicable proxy energy~~Adjustment~~ b~~B~~id curve, Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~)~~ of that Generating Unit or System Resource or Curtailable Demand in the same Trading $Interval_t$ is:

$$PayTI_{ijt} = \sum_b INC_{bijt}$$

B 2.2 Charges to Scheduling Coordinators with decremented schedules

When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating $Unit_i$ or System $Resource_i$ in order to relieve Congestion within a Zone, the ISO will make a charge to the Scheduling Coordinator. The amount that the ISO will charge

Scheduling Coordinator$_j$ for decreasing the output of Generating Unit$_i$ is the lesser of (1) 0.9 times the price specified in the Scheduling Coordinator's proxy~~Day-Ahead or Hour-Ahead~~ energy~~Adjustment~~ b~~B~~id as determined in accordance with Section 7.2.6.1 or (2) the relevant BEEP Interval Ex Post Price multiplied by the quantity of Energy Dispatched. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of a~~(or Imbalance Energy bid) for the Generating Unit$_i$ or~~ System Resource$_i$ is the price specified in the Scheduling Coordinator's Day-Ahead or Hour-Ahead Adjustment Bid (or Imbalance Energy Bid as appropriate) multiplied by the quantity of Energy Dispatched~~rescheduled~~. The formula for calculating the charge to Scheduling Coordinator$_j$ for each block$_b$ of Energy in its applicable proxy energy bid curve, Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~)~~ in Trading Interval$_t$ is:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

B 2.2.1 Total Charge for Trading Interval

The formula for calculating the charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been decreased for all the relevant blocks$_b$ of Energy in the applicable proxy energy bid curve, Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~)~~ of that Generating Unit or System Resource in the same Trading Interval$_t$ is:

$$ChargeTI_{ijt} = \sum_b DEC_{bijt}$$

B 2.3 Not Used

B 2.4 Net ISO redispatch costs

The Trading Interval net redispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Curtailable Demand was decreased during the Trading Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System Resource were decreased during the Trading Interval. The fundamental formula for calculating the net redispatch cost is:

$$REDISP_{CONGt} = \sum_j PayTI_{ijt} - \sum_j ChargeTI_{ijt}$$

Note that $REDISP_{CONGt}$ can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Trading Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net redispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Curtailable Demand was decreased (or increased) during the Trading Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.

B 2.5 **Grid Operations Price**

The grid operations price is the Trading Interval rate used by the ISO to apportion net Trading Interval redispatch costs to Scheduling Coordinators within the Zone with Intra-Zonal Congestion. The grid operations price is calculated using the following formula:

$$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

B 2.6 **Grid Operations Charge**

The Grid Operations Charge is the vehicle by which the ISO recovers the net redispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and Exports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator$_j$ in Trading Interval$_t$ is:

$$GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)$$

B 3 **Meaning of terms of formulae**

B 3.1 **INC_{bijt} - $**

The payment from the ISO due to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is increased or Curtailable Load$_i$ is reduced within a block$_b$ of Energy in the applicable proxy energy bid curve, ~~its~~ Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~)~~ in Trading Interval$_t$ in order to relieve Intra-Zonal Congestion.

B 3.2 **$adjinc_{bijt}$ - $/MWh**

The incremental cost for the rescheduled Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ taken from the relevant block$_b$ of Energy in the applicable proxy energy bid curve, Day-Ahead or Hour-Ahead Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~)~~ submitted by the Scheduling Coordinator$_j$ or generated by the ISO for the Trading Interval$_t$.

B 3.3 **$\Delta incbijt$ - MW**

The amount by which the Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ of Scheduling Coordinator$_j$ for Trading Interval$_t$ is increased by the ISO within the relevant block$_b$ of Energy in its applicable proxy energy bid curve, Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~)~~.

B 3.4 **$PayTI_{ijt}$ - $**

The Trading Interval payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ has been increased or System Resource$_i$ or Curtailable Load$_i$ reduced in Trading Interval$_t$ of the Trading Day.

B 3.5 **DEC_{bijt} - $**

The charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is decreased for Trading Interval$_t$ within a block$_b$ of

Energy in its applicable proxy energy bid curve, Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~resource)~~.

B 3.6 **$adjdec_{bijt}$ - \$/MWh**

The decremental cost for the rescheduled Generating Unit$_i$ or System Resource$_i$ taken from the relevant block$_b$ of Energy of the applicable proxy energy bid curve, Day-Ahead or Hour-Ahead Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~resource)~~ submitted by Scheduling Coordinator$_j$ or generated by the ISO for the Trading Interval$_t$.

B 3.7 **Δdec_{bijt} - MW**

The amount by which the Generating Unit$_i$ or System Resource$_i$ of Scheduling Coordinator$_j$ for Trading Interval$_t$ is decreased by ISO within the relevant block$_b$ of Energy of its applicable proxy energy bid curve, Adjustment Bid curve, ~~(~~or Imbalance Energy bid~~resource)~~.

* * *

ATTACHMENT C

law. The ISO shall cooperate with the affected Market Participant to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

(c) In order to maintain reliable operation of the ISO Control Area, the ISO may share individual Generating Unit Outage information with the operations engineering and/or the outage coordination division(s) of other Control Area operators, Participating TOs, MSS Operators or other entities engaged in the operation and maintenance of the electric supply system whose system is significantly affected by the Generating Unit and who have executed the Western Electricity Coordinating Council Confidentiality Agreement for Electric System Data.

20.4 Staffing and Training To Meet Obligations.

The ISO shall engage sufficient staff to perform its obligations under this ISO Tariff in a satisfactory manner consistent with Good Utility Practice. The ISO shall make its own arrangements for the engagement of all staff and labor necessary to perform its obligations hereunder and for their payment. The ISO shall employ (or cause to be employed) only persons who are appropriately qualified, skilled and experienced in their respective trades or occupations. ISO employees and contractors shall abide by the ISO Code of Conduct for employees contained in the ISO bylaws and approved by FERC.

20.5 Accounts and Reports.

The ISO shall notify Market Participants of any significant change in the accounting treatment or methodology of any costs or any change in the accounting procedures, which is expected to result in a significant cost increase to any Market Participant. Such notice shall be given at the earliest possible time, but no later than, sixty (60) days before implementation of such change.

20.6 Titles.

The captions and headings in this ISO Tariff are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the rates, terms, and conditions of this ISO Tariff.

20.7 Applicable Law and Forum.

This ISO Tariff shall be governed by and construed in accordance with the laws of the State of California, except its conflict of laws provisions. Market Participants irrevocably

ATTACHMENT D

Attachment D – Black-lined Tariff sheets for sharing Generator Outage information with other system operators

20.3.4 Disclosure

Notwithstanding anything in this Section 20.3 to the contrary,

(a) The ISO: (i) shall publish individual bids for Supplemental Energy, individual bids for Ancillary Services, and individual Adjustment Bids, provided that such data are published no sooner than six (6) months after the Trading Day with respect to which the bid or Adjustment Bid was submitted and in a manner that does not reveal the specific resource or the name of the Scheduling Coordinator submitting the bid or Adjustment Bid, but that allows the bidding behavior of individual, unidentified resources and Scheduling Coordinators to be tracked over time; and (ii) may publish data sets analyzed in any public report issued by the ISO or by the Market Surveillance Committee, provided that such data sets shall be published no sooner than six (6) months after the latest Trading Day to which data in the data set apply, and in a manner that does not reveal any specific resource or the name of any Scheduling Coordinator submitting bids or Adjustment Bids included in such data sets.

(b) If the ISO is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 20.3, the ISO may disclose such information; provided, however, that as soon as the ISO learns of the disclosure requirement and prior to making such disclosure, the ISO shall notify any affected Market Participant of the requirement and the terms thereof. The Market Participant may, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement and the ISO shall cooperate with such affected Market Participant to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The ISO shall cooperate with the affected Market Participant to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

(c) In order to maintain reliable operation of the ISO Control Area, the ISO may share individual Generating Unit Outage information with the operations engineering and/or the outage coordination division(s) of other Control Area operators, Participating TOs, MSS Operators or other entities engaged in the operation and maintenance of the electric supply system whose system is significantly affected by the Generating Unit and who have executed the Western Electricity Coordinating Council Confidentiality Agreement for Electric System Data.

ATTACHMENT E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER03-___-000**

AFFIDAVIT OFJAMES MCINTOSH
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CONCERNING THE IMPORTANCE OF MANAGING INTRA-ZONAL CONGESTION BEFORE REAL TIME

1. My name is James McIntosh. I am the Director of Grid Operations for the California Independent System Operator Corporation ("ISO"), a position I have held since April 2001. In that position, I supervise the real-time operation of the ISO Control Area, with a system peak demand of over 45,000 MW, and the ISO Controlled Grid, comprised of the bulk power transmission systems of the Pacific Gas and Electric Company ("PG&E"), Southern California Edison, and the San Diego Gas & Electric Company. Before I joined the ISO in 2000, I was in various line and supervisory system operations positions at PG&E, including grid dispatch and scheduling, since 1971. I was part of the team that guided PG&E's transition during the electric industry restructuring in California. I have represented the ISO and PG&E at industry reliability forums, including the Western Electricity Coordinating Council ("WECC") and the North American Electric Reliability Council. I hold a Bachelor's Degree in Business Management from Saint Mary's College. I am a NERC-certified and WECC-certified system

operator. My business address is 151 Blue Ravine Road, Folsom, California 95630.

2. The purposes of my affidavit are to 1) describe the severe adverse effects of unmitigated Intra-Zonal Congestion; 2) describe what actions the ISO currently must take to manage Intra-Zonal Congestion; 3) describe the problems created by the limited ability the ISO currently possesses to manage Intra-Zonal Congestion; and 4) ultimately establish why the ISO must manage Intra-Zonal Congestion before real time.

Intra-zonal Congestion is a Serious Threat to System Reliability and to Public Safety

3. In economic market theory as applied to transmission system operations, Congestion is the transmission system's inability to accommodate all desired Energy transactions, thus requiring some means to allocate scarce transmission or delivery capacity. In power systems operation terms, however, Congestion means that a power system component is overloaded – a serious condition that must be actively avoided, if at all possible, or, if such an overload cannot be avoided, dealt with immediately and decisively.

4. Taking advance action to prevent components from being overloaded is a universal, foundational principle of power system operations. The Western Electricity Coordinating Council Minimum Operating Reliability Criteria ("MORC") mandate that

> At all times the interconnected system shall be operated so neither the net scheduled or actual power transferred over an

> interconnection or transfer path shall exceed the total transfer capability of that interconnection or transfer path.

MORC Section III.B.1.

5. The potential consequences from overloaded power system components are severe. The overloaded component can be weakened, setting the stage for a future uncontrolled failure, which, in turn, could interrupt customer service. The overloaded component can be damaged to the point it must be replaced, and the replacement work can be costly and can interrupt or reduce the reliability of transmission service. Far more serious than the interruption of customer service, however, are the threats to public and worker safety posed by overloaded transmission facilities. Overloaded transmission lines heat up, expand and sag well below mandated safety limits. While sagging transmission lines may pose little threat to safety in remote, unpopulated areas, sagging lines in urban and suburban areas pose a serious threat to public safety. Beyond the dangers to the public, overloaded lines put workers in the terminating substations and along the length of the line at risk if the line or any of its associated components – oil-filled circuit breakers, wave traps, and disconnect switches - fails. Given all of the possible consequences, prudent power system operations demand that all possible steps be taken first to prevent components from overloading and, if those efforts fail, to immediately reduce overloads as they occur. Consideration of the economic definition of "Congestion" as something that an economic allocation method for a scarce resource can fix inappropriately discounts the

serious threats to public health, worker safety and reliable operation of the transmission system.

Under the Present Zonal Congestion Management Scheme, Managing Intra-Zonal Congestion in Real Time is Unduly Burdensome

6. The ISO began operations on March 31, 1998, with a Zonal Congestion Management model in which transmission constraints between Zones were explicitly modeled. Congestion between Zones was managed in both the forward Day-Ahead and Hour-Ahead markets. Congestion occurring within Zones was presumed to be minor and infrequent. Though this assumption has since proved to be false, the ISO, to this day, has not had a means for managing Intra-Zonal Congestion prior to real time. As a result, instead of managing Intra-Zonal Congestion the same way it managed Inter-Zonal Congestion - by ensuring Schedules cannot cause the Congestion - the ISO has been forced to manage Intra-Zonal Congestion reactively by Dispatching Generating Units in real time.

7. Managing Intra-Zonal Congestion only in real time is a difficult and burdensome process that demands a disproportionate share of the ISO grid operators' time and impinges on their other responsibilities, to the detriment of coordinated, effective grid operations. While the economic effects of Intra-Zonal Congestion are also a problem, the chief problem of Intra-Zonal Congestion, seen from my perspective as the Director of Grid Operations, is the burden that managing Intra-Zonal Congestion in real-time imposes on the ISO's real time operations staff.

8. Consider an example of what the ISO must do to manage Intra-Zonal Congestion in real time. In many instances, due to the vast network of lower-level voltage

transmission and sub-transmission that the ISO manages[1] and that the ISO operators cannot "see" in real time due to the lack of Supervisory Control and Data Acquisition visibility, the ISO's first indication that a component is overloaded typically is a telephone call from the Participating Transmission Owner ("PTO"). Two things are now evident. First, while prudent practice dictates that steps should have been taken in advance to avoid the overload, such steps were not taken simply because the ISO has no means for managing Intra-zonal Congestion prior to real time. Thus, the overload cannot be avoided – it has already occurred. Second, because an overloaded component is a serious threat both to reliable service and to public safety, as described above, the ISO must take immediate action to relieve the overload. Typically, this means the ISO will direct one unit immediately to change its output. Immediate corrective action is often limited to just one unit because that one single unit is the most effective unit - often even the only unit - that can relieve the overload.

9. Furthermore, with the problem already occurring, the ISO cannot afford to take the time to spread the necessary curtailment to a group of units, assuming that there is a group of units under the control of more than one owner that would be effective in relieving the overload. Once the overload is relieved, and the

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[1] Because substantial portions of the 115-kV sub-transmission network belonging to the Pacific Gas and Electric Company and the 69-kV sub-transmission network belonging to the San Diego Gas & Electric Company underlie and parallel the higher voltage transmission networks of those companies, power transmitted from one location to another simultaneously flows on both the transmission lines and the underlying sub-transmission lines. Since these transmission and sub-transmission networks must be operated together, some sub-transmission facilities have been placed under the control of the ISO. In the vertically integrated utilities, sub-transmission lines were often monitored and operated by regional switching centers and were not equipped with the same remote monitoring and control equipment as the transmission facilities. Consequently, the ISO often cannot "see" the flows on these lower-voltage sub-transmission facilities as well as it "sees" the flows on the higher-voltage transmission facilities.

immediate threat to reliability and safety has passed, however, the ISO will try to allocate more equitably the necessary curtailment among generators in that area. That reallocation, however, is an inefficient process for several reasons. First, different Generating Units may have different effects on the loading of the affected component. Second, different Generating Units may respond differently – some even not at all – to the ISO's Dispatch instructions. Such an uncoordinated response may even re-create the overload. Third, as this process unfolds, the Load in the Congested Zone is changing, which in turn can change the effect individual Generating Units have on relieving the overload, and in fact could cause another overload to occur.

10. At the same time the transmission system operator is re-Dispatching Generation to manage the overload, that same operator is necessarily engaged in other things. He or she must be communicating with the ISO's Generation dispatcher, who, in turn, is simultaneously dispatching other Generation to keep the ISO Control Area in Load/Generation balance. Ultimately, whatever actions are being taken to re-Dispatch Generation to manage the Intra-Zonal Congestion must be coordinated and consistent with the ISO's Control Area balancing requirements.

11. The transmission system operator also must stay in contact with the relevant PTO, particularly if the overload is occurring on a lower voltage facility for which the ISO may not have real time visibility. In such a circumstance, the ISO must rely upon information from the PTO to know the details of the loading on the affected transmission facility. Moreover, if the overload occurs near the top of an operating hour, the system operator must work with the other ISO operators and

with the Generators' Scheduling Coordinators to ensure that any changes in Generation intended to position a Generating Unit to satisfy the next hour's Schedules do not re-create the overload. Similarly, the transmission system operator must continue to monitor and predict changes in Load in the affected area to ensure Load changes do not re-create the overload. Finally, the transmission system operators must discharge their primary responsibility: coordinating complex switching needed to accommodate vital scheduled and emergency maintenance.

12. In sum, managing Intra-Zonal Congestion in real time is a process that demands the immediate, concentrated attention of a number of ISO staff, detracts from their primary responsibilities, and can occupy staff for several hours, depending on the load, outage and Generation conditions that create the overload. While some Congestion occurs due to real time equipment failures or other unforeseen consequences and only can be managed in real time, the ISO must do what it can to manage Congestion that it reasonably can anticipate before real time.

13. It is true that the ISO's flawed Zonal Congestion management scheme and the lack of a means to manage Intra-Zonal Congestion in the forward markets creates an economic need to manage Congestion prior to real time (to prevent Generators from engaging in the "dec" game, *i.e.*, scheduling in such a way to deliberately create Congestion that can only be resolved by taking a certain unit's decremental, or "dec" bids in real time). I stress, however, that from a system operations standpoint, the burden that managing Intra-Zonal Congestion places on the system operations staff is at least as important, if not more important than

the economic gaming problems. Simply stated, Intra-Zonal Congestion creates an operational reliability threat and this is why the ISO must have a means to manage Intra-Zonal Congestion before real time.

14. I attended numerous stakeholder meetings in April and May 2002, some of which were attended by Commission staff, in which Market Participants and the ISO tried to develop a mutually agreeable proposal for resolving Intra-Zonal Congestion. While these meetings never did produce a comprehensive consensus on all details for management of Intra-Zonal Congestion, the parties did agree on one thing – that it was essential for the ISO to manage Intra-Zonal Congestion before real time. That is the reason the ISO is proposing this change as part of Amendment No. 50.

15. There are two future permanent solutions to this problem. The first is to implement an LMP-based system that will manage congestion in the forward markets. The ISO has filed such a system as part of its market redesign effort. The second permanent solution is to ensure that the new Generator Interconnection process identifies what additional transmission infrastructure is identified and then assures that such new facilities are fully and timely constructed so that the output from power plants can be delivered under all system conditions, including system contingencies – and not just under peak conditions with all lines in service. Neither of these solutions will be ready soon. The interim solution the ISO proposes to manage Intra-Zonal Congestion before

real time in Amendment No. 50 is necessary to ensure operational reliability until the permanent solutions can be implemented.

16. I declare under penalty of perjury that the foregoing is true and correct.

James McIntosh
Director of Grid Operations

Executed in Folsom, California on March 28, 2003.

State of California

County of Sacramento

On March 28, 2003, before me, Cayden V. Mohr, Notary Public, personally appeared James McIntosh, person know to me to be the person(~~s~~) whose name(~~s~~) is/~~are~~ subscribed to the within instrument and acknowledged to me that he executed the same in his/~~her/their~~ authorized capacity~~(ies)~~, and that by his/~~her/their~~ signature(~~s~~) on the instrument the person, or the entity upon behalf of which the person(~~s~~) acted, executed the instrument.

CAYDEN V. MOHR
Commission # 1293602
Notary Public - California
Sacramento County
My Comm. Expires Feb 9, 2005

WITNESS my hand and official seal.

Signature of Notary Public

ATTACHMENT F

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER03-___-000**

AFFIDAVIT OF ERIC W. HILDEBRANDT ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION CONCERNING THE IMPORTANCE OF MANAGING LOCATIONAL MARKET POWER

1. My name is Eric W. Hildebrandt. I am the Manager of Market Investigations for the California Independent System Operator Corporation ("ISO"), a position I have held since joining the ISO in September 1998. My business address is 151 Blue Ravine Road, Folsom, CA 95360. My responsibilities include monitoring and investigating anomalous market performance and behavior relating to Intra-Zonal Congestion and locational market power. I have worked extensively on locational market power issues, including the investigation of specific Out-of-Sequence ("OOS") ISO Dispatch Instructions issued to relieve Intra-Zonal Congestion and other local reliability requirements, and the mitigation of locational market power through Reliability Must-Run ("RMR") contracts. I hold an M.S. and Ph.D. in Energy Management and Policy from the University of Pennsylvania.

2. The purposes of my affidavit are 1) to review briefly the problem of locational market power within the ISO system, including examples previously filed with the Commission; and 2) to provide another specific example of how locational market power has been, can be, and is being exercised in ISO markets under the ISO's current Tariff and market design.

Locational Market Power

3. Locational market power problems can arise on any electric power network as a result of constraints in the transmission system and the concentration of ownership of generating units within *load pockets* with limited transmission capacity to the main electrical grid. When local system conditions are such that any individual generating unit, or generation from a group of units owned by only one or two suppliers, are needed to ensure local system reliability, local market power can arise, *i.e.*, owners of specific resources needed to ensure local reliability are able to demand unreasonable prices for additional capacity and/or generation needed to ensure local reliability. Locational market power also can arise within *generation pockets* where the amount of energy scheduled by one or more generators may exceed the transmission capacity out of a generation pocket, thereby requiring the ISO to call upon these same generators to reduce their Generation to mitigate the Intra-Zonal Congestion created by this generation pocket.

4. To mitigate local market power, California's original (and current) market design primarily relies upon Reliability Must-Run ("RMR") Contracts with units located at known strategic locations on the transmission grid. Through an annual planning process, the ISO designates specific Generating Units as RMR Units, based on the potential need for these units to be on-line and generate at sufficient levels to provide voltage support, adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability. Units receiving RMR designation[1] are subject to a *pro forma* RMR Contract agreement, which provides specific terms and conditions under which the ISO can Dispatch such units on a day-ahead basis or in real time to ensure that sufficient Energy and on-line Generation within each RMR area are available to meet local reliability requirements. RMR Contracts also provide a mechanism for compensating unit owners for the costs of operating when units are needed for local reliability, but may not be economical to operate based on overall Energy and Ancillary Service market prices.[2] RMR Contracts provide a means of mitigating the

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[1] The ISO designates generating units to be RMR units if the ISO's annual technical assessment indicates such units are needed to meet reliability criteria established by the ISO and stakeholders and approved by the Board of Governors in 1998. The criteria look at system performance during the simultaneous outage of a generating unit and a transmission component that has the greatest effect on system performance.

[2] In addition variable cost payments designed to "make owners whole" for any incremental operating costs incurred when called upon to meet RMR generation requirements, RMR contracts provide a fixed payments to RMR unit owners that have been negotiated (and in some cases litigated) with the unit owners by the ISO and the owner of the portion of the transmission system in which the RMR unit is located.

exercise of local market power in cases where incremental Energy is needed for local reliability by ensuring that the ISO has the ability to call upon RMR units to provide Energy at a pre-agreed, cost-based rate if the level of RMR generation needed to meet local reliability requirements is not scheduled through a market transaction. In the absence of RMR Contracts, Generation owners could, under certain load conditions, bid capacity at a very high price in the real-time Energy market and force the ISO to meet local reliability requirements by dispatching Energy OOS at these uncompetitive high bid prices.

5. RMR Contracts mitigate the ability of units to exercise locational market power when they are needed for incremental Generation. There are certain events, however, such as temporary transmission outages, unit outages (including outages of RMR Units), or other extraordinary system conditions that can create a need for the ISO to call virtually any unit on the grid, not just RMR Units, to ensure local system reliability. In addition, since the terms of the ISO's *pro forma* RMR Contract provide a way for the ISO to ensure sufficient incremental energy (or on-line capacity) to ensure local area reliability within load pockets, RMR Contacts, which were developed to prevent generators from exercising market power by withholding supply, do not limit the ability of units to exercise locational market power when local system conditions are such that the ISO must limit or decrease the amount of Energy a unit produces.

6. In cases where Intra-Zonal Congestion cannot be mitigated by Dispatching an RMR Unit for additional incremental energy, the ISO must call real time Energy bids submitted by specific units OOS to resolve Intra-Zonal Congestion. Although bids dispatched OOS do not set the overall market clearing price, bids accepted OOS are paid at the bid price, so that generators have the ability to exercise locational market power whenever the ISO must issue OOS calls for incremental or decremental Energy from just one or two specific units.

Previously Filed Examples of Locational Market Power

7. The concern that Generators have opportunities to profit unduly from Intra-Zonal Congestion and other locational reliability constraints is not simply theoretical; the ISO has observed this behavior on a numerous occasions.

8. The single most egregious example of the exercise of locational market power, which involved the Huntington Beach and Alamitos plants owned and operated by AES Southland, Inc., and marketed by Williams Energy Marketing and Trading Company is well documented before the Commission.[3] While this incident is notable due to the magnitude of the excess charges involved and the detailed investigation that ensued, the basic situation involved in this case is no way an isolated incident. Prior to this incident, a series of similar incidents were brought to the

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[3] *See AES Southland, Inc. and Williams Energy Marketing and Trading Company,* 94 FERC ¶ 61,248 (2001) (including Non-Public Appendix released on November 15, 2002); and *AES Southland, Inc. and Williams Energy Marketing and Trading Company,* 95 FERC ¶ 61,167(2001).

Commission's attention in the ISO's Answer to Motions to Intervene in its filing of proposed Tariff Amendment No. 23.[4]

9. Meanwhile, examples of the exercise of locational market power when the ISO has needed to limit or decrement Generation previously were documented before the Commission in the ISO's Answer to Motions to Intervene in the Tariff Amendment No. 23 proceeding.[5] Another particularly egregious example of the exercise of locational market power during temporary system conditions requiring that specific Generating Units be limited or decremented has been documented in a recent weekly Market Monitoring Report submitted to the Commission pursuant to the April 26 Order.[6]

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4 *See* "Answer Of California Independent System Operator Corporation To Motions To Intervene, Comments, Protests, And Request For Hearing," *California Independent System Operator Corporation,*] Docket No. ER00-555-000, at pp.14-15 (December 20, 1999).

5 *See* "Answer Of California Independent System Operator Corporation To Motions To Intervene, Comments, Protests, And Request For Hearing," *California Independent System Operator Corporation,* Docket No. ER00-555-000, at p. 15 (December 20, 1999).

6 *See Market Monitoring Report*, December 20 – December 26, 2002, Attachment A submitted as directed in *San Diego Gas & Electric Company, et al*, 95 FERC ¶ 61,115 (2001) (April 26 Order).

New Documentation of Exercise of Locational Market Power

10. Another recent example of locational market power is described in detail in a report being submitted as a confidential Attachment G to this filing. This attached report quantifies over $1 million in additional OOS costs incurred due to locational market power by a single owner/operator over a five-week period in October-November 2002. Examination of overall bidding patterns also indicates that bid prices for units involved in this example increased noticeably after the units began to be called OOS by the ISO due to temporary transmission constraints, providing further evidence that unit operators actively seek to exploit locational market power when they are in a position to do so.

11. In addition, as described in the attached report, results of this analysis also indicate that over $400,000 of costs incurred through OOS calls to these non-RMR Units may be attributable to a series of outages at an RMR Unit under control of the same owner and Scheduling Coordinator. The technical issue concerning whether the outages may have been avoidable or unnecessarily prolonged is the subject of a separate series of activities, including mandatory site inspections, conducted by the ISO's Outage Coordination Department. This report quantifies the financial impact of outages at the RMR Unit investigated, but come to no conclusion about whether the RMR Unit outages may have been avoidable or unnecessarily prolonged. As illustrated in this example, however, RMR Unit outages currently can have a direct and significant

impact on the degree to which the ISO must issue OOS calls to non-RMR units under control of the same owner and Schedule Coordinator. Under the current rules governing mitigation of locational market power by non-RMR Units, this situation creates a potential gaming opportunity stemming from the fact that an RMR Unit operator may benefit from RMR Unit outages in cases where such outages require the ISO to call a non-RMR Unit OOS to ensure local reliability. Given the difficulties often associated with determining whether outages might have been avoidable or prolonged, this also makes it extremely difficult for the ISO and other regulatory entities, including FERC Oversight and Investigation staff, to assess intentionality and then "police" such incidents through existing investigative and sanctioning authority.

12. In sum, the example provided in Attachment G provides further evidence that locational market power can be and has been exercised under current market rules that have been approved by the Commission,[7] and that the financial impacts of this locational market power can be significant.

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[7] The Commission directed the ISO to implement local market power mitigation through the Automated Mitigation Procedures that the ISO implemented on October 30, 2002. *See California Independent System Operator Corporation*, 100 FERC ¶ 61,060 (2002) at PP 77-94.

13. I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Eric W. Hildebrandt, Ph.D.
Manager of Market Investigations

Executed in Folsom, California on March 28, 2003.

State of California

County of Sacramento

On March 28, 2003, before me, Cayden V. Mohr, Notary Public, personally appeared Eric W. Hildebrandt, person know to me to be the person(~~s~~) whose name(~~s~~) is/~~are~~ subscribed to the within instrument and acknowledged to me that he executed the same in his/~~her/the~~ir authorized capacity~~(ies)~~, and that by his/~~her/their~~ signature(~~s~~) on the instrument the person, or the entity upon behalf of which the person(~~s~~) acted, executed the instrument.

CAYDEN V. MOHR
Commission # 1293602
Notary Public - California
Sacramento County
My Comm. Expires Feb 9, 2005

WITNESS my hand and official seal.

Signature of Notary Public

ATTACHMENT G

Privileged Information Has Been Redacted
Pursuant to 18 C.F.R. § 388.112

ATTACHMENT H

200209125020 Received FERC OSEC 09/12/2002 01:52:00 PM Docket# ER02-1656-000, ET AL.

Comments on Mitigating Local Market Power and Interim Measures For Intra-Zonal Congestion Management

**Frank A. Wolak, Chairman; Brad Barber, Member;
James Bushnell, Member; Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO**

September10 , 2002

Introduction

The California Independent System Operator (CAISO) is currently appealing to the Federal Energy Regulatory Commission (the Commission) for the tools to deal with local market power problems associated with intra-zonal congestion management (AZCM). These two issues are so intimately related that it is more productive to address them in a combined solution. In particular, the combination of local market power and zonal congestion management has led to chronic problems with the intentional over-scheduling of generation at certain locations in the transmission network. This practice has come to be known as the "dec game." To provide meaningful relief to the reliability and economic costs associated with intra-zonal congestion, any measure approved by FERC must mitigate the local market power that greatly magnifies the severity of "dec game." The solutions approved to date, specifically those laid out in the Commission's July 17th order on California's MD02 market redesign Docket No. ER02-1656, do not adequately address this problem. Significant amounts of local market power can still be exercised under this mechanism. For this reason, the Commission should not defer implementing a solution to this problem until the end of the California market redesign process. This would create an intolerable delay in addressing unjust and unreasonable market outcomes, with serious near-term economic and reliability consequences for California.

The Problem: The Combination of Zonal Pricing *and* Local Market Power

Because the California ISO does not have the authority to mitigate the bids of market participants with local market power, intra-zonal congestion costs have been much more frequent and severe than projected at the start of market, with costs to the ISO now averaging over a million dollars per month. The largest source of intra-zonal congestion costs continues to be the "dec game," where generation unit owners are paid substantial sums for essentially doing nothing because of the local market power they possess.

This problem arises in circumstances where producers attempt to put too much power into a location on the grid. Under a locational pricing scheme with adequate pricing points, the locational price earned by such suppliers would be near zero or even negative. With forward market self-scheduling that only respects inter-zonal transmission constraints, producers schedule at whatever level they wish subject to inter-zonal transmission constraints. If the ISO subsequently needs to manage intra-zonal congestion, unit owners can offer to "buy back" their generation obligation from the ISO with a decremental energy (dec) bid. If firms were perfectly competitive, such bids would reflect the marginal costs avoided by not producing. However, in the vast majority of circumstances, firms possess local market power, meaning that they are aware of the fact that no other firm can relieve this intra-zonal constraint. Consequently, the ISO often has no choice but to accept dec bids at implausibly low, and often *negative*, prices. With a negative dec bid, the supplier is paid not to generate.

Under the system conditions when a generation unit owner knows that it is the only firm able to relieve an intra-zonal transmission constraint, it is not surprising that the ISO finds itself with too much power scheduled through these portions of its network. The source of the problem is economic, but the consequences threaten the reliability of the network. The magnitude of these economic and reliability consequences make it a problem that must be dealt with immediately, not deferred until the resolution of the market redesign process.

It is important to emphasize that although a locational marginal pricing scheme wouldargely eliminate the dec game, local market power problems will continue to exist in a different form. Under a locational marginal pricing scheme, local market power is exercised by withholding electricity from the market. This withholding will occur when a generation unit owner knows a certain amount of energy must be supplied by some of the units it owns or local demand will not be met because of transmission constraints into this area. Unless there is significant price-responsive demand at this location, there is no limit to the price that this unit owner can bid for the required amount of energy. Consequently, without the authority to mitigate the bids of this unit owner when it possesses local market power, there is no limit to price of energy at that location. For this reason, all of the US ISOs that use locational marginal pricing have mechanisms to mitigate the bids of generation unit owners with local market power.

The Solution: Mitigate the Perverse Economic Incentives that Create the Problem

Any solution to this local market power problem must reduce the magnitude of the profits that firms can earn from attempting to exercise it. If this market power is sufficiently mitigated, then these firms will find it profit-maximizing to schedule their units in a manner that reduces, rather than enhances the likelihood of intra-zonal congestion.

In its standard market design (SMD) proposals, the Commission has emphasized the need to mitigate the local market power of suppliers who are advantageously located within the network. However, because the SMD also emphasizes a high-resolution locational marginal pricing (LMP) scheme for transmission, there is no consideration of the peculiar ways in which local market power manifests itself under zonal congestion management schemes such as the one that currently exists in California. As discussed above, the focus of local market power mitigation measures under locational marginal pricing is on preventing certain suppliers from bidding unreasonably *high* prices. Even the market power mitigation components of the Reliability Must-Run (RMR) agreements in California focus only on this problem. These agreements were intended to cover system conditions when local market power mitigation is needed to prevent unreasonably high prices. But local market power most often manifests itself under the current California market design through suppliers bidding unreasonably *low* prices.[1] Therefore meaningful local market power regulation in California must mitigate offer prices in both of these directions.

Mitigating the bids on units required to provide intra-zonal congestion relief is a relatively simple means of addressing the most severe circumstances of the local market power problem.[2] The Commission has already approved the use of bid mitigation for such purposes in California, but several aspects of the measures outlined in the Commission's July 17th order make them ineffectual for the current California market design unless they are revised in the manner described below.

First, the usage of a *maximum* bid price threshold below which no mitigation would apply clearly fails to address the more severe problem of bids that are unreasonably *low*. Second, the mechanism described in the Commission's July 17th order allows bid ranges around the reference price that are in our opinion inappropriately loose for an application to a circumstance of local market power. A generation unit owner can exercise a sizeable amount of local market power and still not trigger the bid mitigation process in the Commission's July 17th order. This is particularly true for case of bidding unreasonably low. Bidding negative $30/MWh, the negative bid cap in the Commission's July 17th order, still allows a firm to be a paid substantial sum of money for submitting a day-ahead energy schedule that it knows is infeasible.

Our revisions to the process outlined in the July 17th order for immediate application addresses these shortcomings. We recommend applying a narrow band, no larger than ten percent, *in either direction* around the reference price as the threshold for mitigation in the circumstance of local market power because of intra-zonal congestion. In our view, a reasonable standard for when a firm possesses local market power is that it and one other firm are the only market participants with generating units able to solve this intra-zonal congestion constraint given the day-ahead energy schedules of all market participants. Furthermore, we would not recommend employing an initial bid-price threshold to trigger mitigation for local market power. This "less than three firms" criterion for determining whether a firm possesses local market power is our preferred condition for bid mitigation to occur. We also recommend using incremental production costs for thermal resources, rather than historic bids, as the basis for constructing the reference price.

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[1] According to the CAISO, AZCM dec costs have been roughly 10 times the magnitude of AZCM inc costs over the last 2 years.

[2] Even with incremental and decremental bids that accurately reflect the operating costs of the plant, a firm may still have an incentive to inefficiently schedule power into a congested part of the network. If the zonal price were sufficiently above marginal cost, a firm could still profit from the difference between the zonal price and its 'dec' obligation. While the implementation of a higher resolution of locational marginal pricing is needed to completely eliminate these incentives, we believe that eliminating the most extreme profit opportunities through the mitigation of dec bids in manner we suggest will provide sufficient relief to the ISO.

Using bids in previous competitive periods as a reference price for mitigation can lead to distortions in the firm's bids during these hours because the firm may find it long- or medium-term profit-maximizing to influence its reference price during those hours. The potential for such distortions is a cause of the misgivings we hold about using AMP for system-wide mitigation. While such distortions may not be severe when combined with relatively broad conduct and impact thresholds, the linkage of bids across reference hours and mitigation hours would be much stronger with more narrow thresholds. Thus while an AMP mechanism might mitigate bids during hours of market power, it may also distort bids during hours in which the market is relatively competitive. For these reasons we feel that a cost-based reference price is most appropriate for local market power mitigation.[3]

Implementing a solution

The ISO has expressed growing concern about its ability to manage intra-zonal congestion in a reliable manner. Because of these concerns, the ISO has requested the ability to enforce advanced schedules that are feasible with regards to both intra-zonal as well as inter-zonal congestion.

We believe that by putting in place a mechanism that automatically mitigates the bids of unit owners with local market power, the economic incentive to intentionally submit infeasible schedules and the incidence of intra-zonal congestion will be significantly reduced. The negative reliability consequences of the CAISO of managing AZCM should also be less extreme. Simply maintaining the current procedure of relying on adjustments in the real-time energy market, but with mitigated bids for units with local market power would go a long way toward limiting the perverse incentives causing the problem. However, there is a legitimate concern that this still places too much pressure on the real-time market, with potentially serious consequences for reliability.

To deal with these reliability concerns, the CAISO could combine its desire to curtail overscheduled generation in advance with a process for achieving such curtailment in an efficient manner. Using the mitigated bids of units with local market power as intra-zonal adjustment bids could achieve this. Instead of curtailing schedules according to a pro-rata measure, the adjustments would occur in accordance with the ordering of these adjustment bids. Any curtailment scheme could be combined with a process that allows for suppliers to adjust their advance schedules voluntarily, giving them the opportunity to reach an efficient set of aggregate schedules through bilateral arrangements before the ISO would have to intervene. Specifically, after the close of the

[3] One might think that the firm may not recover its annual going forward fixed costs of operation if it is mitigated to this level too frequently. However, as noted above, we expect this mitigation to apply primarily to decremental energy bids, which are the prices that firms must purchase energy scheduled in the forward market back from the ISO. The vast majority of instances of bid mitigation for incremental energy should be covered by RMR contracts, which pay generators annual fixed payments to cover their going forward fixed costs. However, in the unlikely event that a plant does not recover its annual going forward fixed costs because of this local market power mitigation mechanism, the unit owner could apply to the Commission for ex post relief through an uplift payment from the ISO.

hour-ahead market, the ISO could use the mitigated adjustment bids for those units with local market power and the unmitigated adjustment bids of the remaining firms to compute final hour-ahead schedules that are feasible in terms of both intra-zonal and inter-zonal transmission constraints. In the event that suppliers submit hour-ahead schedules that are feasible from both an intra-zonal and inter-zonal perspective, this process would not be necessary. [4]

It is important to note that the implementation of locational marginal pricing that is part of the ultimate California market re-design process will not eliminate the local market power problem. It will only take a different form. Some scheme for mitigating local market power is still necessary. All the eastern ISOs have local market power mitigation schemes that are more rigorous than those proposed for California in the July 17^{th} order. For example, the PJM ISO has an automatic mechanism that mitigates the bids of market participants that the ISO determines to possess local market power to their filed variable cost plus a 10 percent adder. Consequently, there is no reason to defer the solution of this problem to the completion of California market redesign process, because the ultimate solution to this problem and the present solution are the largely the same.

[4] As long as the ISO specifies in advance what will occur if generation unit owners fail to submit feasible, from an inter-zonal and intra-zonal perspective, hour-ahead schedules, trading among scheduling coordinators should take place to move closer to this outcome. For this reason, we recommend that the ISO to manage any remaining intra-zonal congestion at the end of the hour-ahead market to minimize the as-bid re-dispatch costs using both the mitigated bids of generation units with local market power and the bids of units without local market power, rather than the pro-rata allocation scheme proposed in Amendment 47. With this intra-zonal congestion management backstop in place, generation unit owners have very good idea what intra-zonal transmission capacity will be ultimately allocated to each generation unit owners. Trading among market participants could then take place to arrive at a fully feasible final schedule. Generating companies could reallocate capacity among their units or trade transmission capacity with other companies that would like to schedule generation out of a local area. In the event that this trading failed to yield fully feasible hour-ahead schedules, the backstop of minimizing as bid re-dispatch costs to compute feasible schedules would be implemented at the close of the hour-ahead market.

ATTACHMENT I

Western Electricity Coordinating Council
Confidentiality Agreement for Electric System Data
September 27, 2002

1. **Parties to this Agreement.** This Agreement is among the Data Recipients who are the signatories to this document, and between each of the Data Recipients of the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC).

2. **Background**. To maintain the operational security of the bulk electric system, the NERC and WECC Operating Policies require that specific information, which is referred to in this Agreement as "Operational and Security Data" (Data), regarding operating conditions within each Control Area, be made available to (1) other Control Areas, (2) Reliability Coordinators, and (3) those entities responsible for real-time operational security. Because Operational and Security Data can be competitively sensitive in the electric energy market, and is therefore considered proprietary in nature, the availability and confidentiality of that Data must be protected. To ensure that such information is available only to those responsible for maintaining the operational security of the electricity supply in the North American power system and the Western Interconnection, and not made available nor used by any entities engaged in the Energy Merchant Functions, Operational and Security Data will be collected from all control areas and other entities who are directly responsible for the immediate, real-time operations of the bulk electric system. Such data will be made available only to those entities directly responsible for immediate real-time operational security, who are also signatories to and comply with this agreement. Any such entity is hereafter referred to as a Data Recipient.

3. **Definitions**.

   3.1. **Reliability Coordinator**. An entity responsible for the operational security of one or more control areas.

   3.2. **Control Area**. An electrical system bounded by interconnection (tie line) metering and telemetry. It controls its generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the Interconnection.

   3.3. **Operational and Security Data**. Information pertaining to the electric system which is used for analyzing the operational security of the North American power system and the Western Interconnection, including information in the EHV Data Pool and WECCNet Message System. Security Data is available from Reliability Coordinators, Interregional Security Network (ISN), WECC Operations Network (WON), control areas or other operating entities directly responsible for the immediate real-time operations of the bulk electric system.

3.4. **Data Supplier**. Control Areas, Reliability Coordinators, and other entities who are directly responsible for the immediate, real-time operations of the bulk electric system, who supply Operational and Security Data, either manually or automatically, to their Reliability Coordinator(s), other Reliability Coordinators, or other Control Areas.

3.5. **Data Recipient**. Control Areas, Reliability Coordinators and other entities who are directly responsible for the immediate, real-time operations of the bulk electric system, who obtain Operational and Security Data, either manually or automatically, from their Reliability Coordinator(s), the WECC WON, ISN, Control Areas or other operating entities directly responsible for the immediate real time operation of the bulk electric system.

3.6. **WECC Operations Network (WON).** The telecommunications and data system used to share Operational and Security Data among the Data Recipients. The WON serves as the communication medium for the WECC EHV data pool, WECCNet (message system) and the Inter-utility Data Exchange.

3.7. **NERC Interregional Security Network (ISN).** The NERC communication and data system used to share Operational and Security Data among the Data Recipients.

3.8. **Energy Merchant Function.** Any purchase or sale of electric energy or Interconnected Operations Services for any commercial reason.

3.9. **Merchant Employee**. Within an organization, any employee who engages in Energy Merchant Functions.

4. **Standards of Conduct**. A Data Recipient must conduct its business to conform with the following standards:

4.1. **General Rules.**

4.1.1. **Prohibitions**. Any Merchant Employee of the Data Recipient or its affiliate, engaged in Energy Merchant Functions is prohibited from having access to the Operational and Security Data, except as it may be made available to all Energy Merchant Functions simultaneously by means other than the WON or ISN.

4.1.2. Except as emergency conditions dictate as discerned by a Reliability Coordinator or Control Area, the employees of a Data Recipient must function independently of the Merchant Employees within that organization or its affiliates.

4.1.3. Notwithstanding any other provisions herein, in emergency circumstances that could jeopardize operational security, Data Recipients may take whatever steps are necessary to maintain system security. Data Recipients must report to the Reliability Coordinator each emergency that results in any deviation from this agreement within 12 hours of such deviation.

4.1.4. Employee Transfers. Employees engaged in either the Energy Merchant Function (Merchant Employees) or real-time transmission system operations reliability function are not precluded from transferring between functions as long as the transfer is not used as a means to circumvent the standards of this agreement. Notice of any employee transfer between reliability and Energy Merchant Functions shall be provided on the Open Access Same-Time Information System and to the Reliability Coordinator within 24 hours of the transfer.[1]

4.1.5. Disclosure. Any employee of the Data Recipient, or any employee of an affiliate, engaged in system operation reliability functions shall not disclose to Merchant Employees of the Data Recipient, or any of its affiliates, any Operational and Security Data concerning the operating conditions of the electric system based on data receive as related to this Agreement. The Data Recipient shall not, even under conditions of confidence, make available, disclose, provide, or communicate the Operational and Security Data to any other party who is not a signatory to this Agreement, to the extent law allows.

4.1.6. Auditing. The Data Recipient must educate its employees, and any employee of an affiliate engaged in transmission system operations, in the provisions of this Agreement and provide any information upon request to the Western ElectricityCoordinating Council necessary to determine compliance with the terms and conditions of this Agreement, including confidentiality agreements thereto.

5. Disclaimer. Each Data Recipient acknowledges and agrees that the Data Supplier generates and gathers such Operational and Security Data to meet the Supplier's sole needs and responsibilities. Each Data Supplier provides and each Data Recipient receives any and all Operational and Security Data "as is" and "with all faults, errors, defects, and inaccuracies." No Data Supplier makes any representations or warranties whatsoever with respect to the availability, currentness, accuracy, reliability, or suitability of any Operational and Security Data pursuant to this Agreement. Each Data Supplier and each Data Recipient disclaims and waives all rights and remedies that it may otherwise have with respect to any and all representations, warranties and liabilities of each Data Recipient, express or implied, arising by law or otherwise, with respect to any faults, errors, inaccuracies or omissions, availability, currentness, reliability or suitability of the Operational and Security Data. Each Data Recipient assumes any and all risk and

[1] For the purpose of this Agreement, "transfer" includes job change(s) within or between organizations such that the employee works in both functions within a six-month period.

responsibility for its selection and, or use of, and reliance on, any Operational and Security Data.

6. **Term and Termination.**

6.1. **Term.** The term of this agreement shall commence immediately upon the signature of an officer of the Data Recipient and shall remain in effect until terminated.

6.2. **Termination.** Any Data recipient wishing to terminate this agreement shall notify the WECC in writing of its desire to terminate this agreement. Termination shall be effective 30 days following acknowledgement of receipt of such written notice, at which time the Data Recipient will be prohibited from further receipt of the Operational and Security Data.

6.2.1. Termination does not excuse the Data Recipient from supplying Operational and Security Data if required in NERC and WECC Operating Policies and Criteria.

6.2.2. Termination does not excuse the Data Recipient from holding confidential any forecasted Operational and Security Data until eight days after the forecast period has passed.

7. **Governmental Authority.** This Agreement is subject to the laws, rules, regulations, orders and other requirements, now or hereafter in effect, of all regulatory authorities having jurisdiction over the Operational and Security Data, this Agreement, the Data Suppliers, and the Data Recipients. All laws, ordinances, rules, regulations, orders and other requirements, now or hereafter in effect, of governmental authorities that are required to be incorporated in agreements of this character are by this reference incorporated in this Agreement.

8. **Non-compliance.** Data Recipients found to be not in compliance with this Agreement by NERC or WECC or their designated representatives will be prohibited from further receipt of the Operational and Security Data from its Reliability Coordinator(s), ISN, WECC WON or Control Areas until WECC is assured, and agrees, that the Data Recipient has resumed compliance with this Agreement. Non-compliance does not excuse the Data Recipient from supplying Operational and Security Data if required in NERC and WECC Operating Policies and Criteria, nor does it excuse the Data Recipient from holding confidential any forecasted Operational and Security Data until the forecast period has passed.

9. **Due Diligence.** All signatories to this Agreement shall use due diligence to protect the NERC Interregional Security Network and WECC Operations Network, as well as Operational and Security Data, from improper access.

10. Disputes. Disputes arising over issues regarding this Agreement will be settled in accordance with the dispute resolution procedures of the Western Electricity Coordinating Council.

11. Governing Law. This Agreement shall in all respects be interpreted, construed and enforced in accordance with the laws of the state or province of the Data Recipient (without reference to rules governing conflicts of law), except to the extent such laws may be preempted by the laws of the United States of America, Canada, or Mexico as applicable.

12. Integration. This Agreement constitutes the entire agreement of the Parties.

OFFICER OF DATA RECIPIENT

System: ______________________________

By: ______________________________

Title: ______________________________

Date: ______________________________

599491

ATTACHMENT J

NOTICE SUITABLE FOR PUBLICATION IN THE FEDERAL REGISTER

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER03-_____ -000**

Notice of Filing

[ ]

Take notice that the California Independent System Operator Corporation ("ISO"), on March 31, 2003, tendered for filing with the Commission Amendment No. 50 to the ISO Tariff. The purpose of Amendment No. 50 is to modify the Tariff to provide for a means to improve management of Intra-Zonal Congestion until the ISO implements Locational Marginal Pricing ("LMP") or some other long-term comprehensive solution, and to allow the ISO to share Generator Outage information with entities operating transmission and distribution systems affected by the Outage.

The ISO states that this filing has been served on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties with effective Scheduling Coordinator Agreements under the ISO Tariff.

The ISO is requesting that Amendment No. 50 be made effective May 30, 2003.

Any person desiring to be heard or to protest the filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). All such motions or protests must be filed in accordance with § 35.9 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).