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December 21, 2005

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER06-____- 000

Amendment No. 73 to the CAISO Tariff
Request for Expedited Consideration of Tariff Revisions and for Shortened Comment Period

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Sections 35.11 and 35.13 of the regulations of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 35.11, 35.13, the California Independent System Operator Corporation ("CAISO") respectfully submits for filing an original and five copies of an amendment to the CAISO Tariff ("Amendment No. 73").[1] Amendment No. 73 revises the CAISO Tariff to change the current "soft" $250/MWh Damage Control Bid Cap for real-time Energy bids and Adjustment Bids to a "hard" $400/MWh Damage Control Bid Cap, effective as of January 1, 2006 or as soon thereafter as possible. As described below, the CAISO respectfully requests that the Commission issue an order on Amendment No. 73 on an expedited basis in accordance with the Commission's *Guidance Order on Expedited Tariff Revisions for Regional Transmission Organizations and Independent System Operators*, 111 FERC ¶ 61,009 (2005) ("Expedited Tariff Revisions Guidance Order"). Accordingly, the CAISO also requests that the Commission establish a shortened comment period on Amendment No. 73.

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1 Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the CAISO Tariff.

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.

I. BACKGROUND

Section 28 of the CAISO Tariff establishes a "Damage Control Bid Cap" ("bid cap") that sets a limit on the level of bids submitted for the CAISO's Energy and Ancillary Service capacity markets. This bid cap also applies to Adjustment Bids used in the Day-Ahead and Hour-Ahead Congestion Management markets. Currently, pursuant to Section 28.1.2 of the CAISO Tariff, the Damage Control Bid Cap is set at $250/MWh. The Damage Control Bid Cap has been $250/MWh since it was implemented in October 2002 as part of Phase 1A of the CAISO's Market Redesign 2002. *See* Transmittal Letter for CAISO Compliance Filing, Docket Nos. ER02-1656-001, *et al.* (Oct. 29, 2002), at 4; *California Independent System Operator Corp.*, 100 FERC ¶ 61,060, at P 46 (2002) ("July 17, 2002 Order"). Section 28.1.2 currently provides that Market Participants may submit bids above the cap, but that any accepted bids that are above the cap are not eligible to set the Market Clearing Price and are subject to cost justification and refund. The ability of Market Participants to submit above-cap bids that do not set the Market Clearing Price makes the current Damage Control Bid Cap a "soft" bid cap. *See California Independent System Operator Corp.*, 101 FERC ¶ 61,061, at P 17 (2002) ("October 11, 2002 Order"); *California Independent System Operator Corp.*, 112 FERC ¶ 61,013, at P 90 n.61 (2005).

In addition, pursuant to the west-wide market power mitigation program established by the Commission, a bid cap of $250/MWh also applies to all current sales in Western Electricity Coordinating Council ("WECC") spot markets. *See* July 17, 2002 Order at P 46; October 11, 2002 Order at P 17; *California Independent System Operator Corp.*, 108 FERC ¶ 61,254, at P 4 n.7 (2004).

On July 1, 2005, the Commission issued an order directing that, coincident with the planned implementation of the CAISO's Market Redesign & Technology Upgrade ("MRTU") in 2007, the current soft bid cap of $250/MWh should be replaced with a "hard" bid cap (*i.e.*, a bid cap that Market Participants' bids are not permitted to exceed) of $500/MWh that will transition to a hard bid cap of $1,000/MWh over the subsequent two years. *California Independent System Operator Corp.*, 112 FERC ¶ 61,013, at P 104 (2005).

Recently, the CAISO's Department of Market Monitoring ("DMM") asked the CAISO's Market Surveillance Committee ("MSC")[2] to provide an opinion

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[2] The MSC "provides independent external expertise on the [CA]ISO market monitoring process and makes recommendations to the [CA]ISO Chief Executive Officer (CEO) and the [CA]ISO Governing Board." *California Independent System Operator Corp.*, 106 FERC ¶ 61,179,

concerning whether recent increases in the prices of natural gas justify raising the level of the bid cap with regard to the real-time Energy market.[3] Pursuant to the DMM's request, on November 9, 2005, the MSC issued a paper entitled "Raising the Level of the Bid Cap on the Real-Time Energy Market in California" ("MSC Recommendation Paper"), which is provided as Attachment D to the instant filing. In that paper, the MSC recommends that the bid cap on the real-time Energy market be increased to $400/MWh prior to this winter. MSC Recommendation Paper at 1, 5. The MSC explains that "the primary concern at the present time is the risk of generation unit-level variable costs approaching or rising above the cap level. . . . [W]e believe that the likelihood of substantially higher natural gas prices during the winter of 2005 is sufficiently high to justify raising the bid cap at the present time." *Id.* at 1.[4]

The MSC states that increasing the bid cap would lower the risk of a shortfall in the supply of electricity to California caused by generation unit-level variable costs exceeding the bid cap level, but would also have the potential to result in higher costs for consumers due to generators increasing their bids in response to the increase in the bid cap. MSC Recommendation Paper at 1-2. In comparing these risks, the MSC finds that, "[g]iven the relatively small amount of power now purchased at short-term market prices, we view the risk of supply shortfall to be a much more serious threat to California consumers than the potential cost consequences of increasing the bid cap." *Id.* at 1.

The MSC explains that it recommends an increase of the bid cap to $400/MWh, rather than to some different level, based on an analysis of average values of Henry Hub futures prices for the upcoming winter, using information on the heat rate of the least efficient class of natural gas-fired units and estimates of the variable operating and maintenance costs of these units. MSC Recommendation Paper at 4. The MSC concludes that a bid cap level of $400/MWh "should be high enough to make it very unlikely that the [CA]ISO will need to increase the cap again before February of 2007, when the locational marginal pricing (LMP) market is scheduled to be implemented" as part of MRTU. *Id.* at 1. The MSC also notes that gaining "[s]ome experience with a higher bid cap with [the] current market design" would be the preferred "strategy for transitioning to the eventual $500/MWh [MRTU] bid cap." *Id.* at 5-6.

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at P 143 n.75 (2004).

3 The DMM did not request that the MSC provide an opinion with regard to the Ancillary Service markets. As stated below, the CAISO does not propose a change to the current bid cap of $250/MWh that applies to the Ancillary Service markets.

4 The MSC Recommendation Paper refers to the "winter of 2005" (at 1), "this winter" (at 2), and the "winter of 2006" (at 4 and 5). From the context, it is clear that all of these references are to the upcoming 2005-2006 winter season.

The DMM, in a memorandum dated December 9, 2005 from Keith Casey, Director of Market Monitoring, to the CAISO Operations Committee ("DMM Memorandum," provided as Attachment E to the instant filing), states that it supports an increase to the current bid cap. DMM Memorandum at 1. After providing an analysis of the changes in market conditions that have occurred over the past several years, the DMM concludes that raising the real-time Energy bid cap under current market conditions would provide the following significant benefits to the California energy markets:

- Raising the bid cap will provide greater incentives for generation owners to maintain their units at a high level of availability, which will mitigate the risk of experiencing a forced outage during critical peak load hours.

- Raising the bid cap will provide greater incentives for further development of demand response programs such as real-time pricing. Such demand programs will reduce reliance on high-cost, environmentally unfriendly combustion turbines during critical peak demand hours and increase supply margins during peak load periods.

- Increasing the bid cap will promote reliability by providing greater fixed cost recovery for generating units during high demand periods when supply margins are tight and prices are at or near the bid cap. Several generating units in California are at risk of retirement due to insufficient fixed cost recovery. Moreover, some new generating units in the CAISO Control Area do not have long-term power contracts and a higher spot price during critical peak periods will help to make these units more economically viable.

- If gas prices should escalate significantly over the winter months in response to high gas heating demand or supply disruptions, a higher cap will not discourage suppliers, particularly importers, from selling into the California real-time Energy market since such suppliers would be assured of bid cost recovery for accepted bids above $250/MWh. A higher cap will also provide a greater incentive to internal suppliers with options of selling their output to external load through the western bilateral short-term energy markets to instead provide real-time Energy bids to the CAISO.

- A higher bid cap will provide greater incentives for the load-serving entities ("LSEs") to continue to minimize their spot market exposure by signing additional long-term power contracts.

- Increasing the bid cap to $400/MWh will provide a measured transition to the $500/MWh energy bid cap scheduled to be implemented with the CAISO's new market design in February 2007.

Id. at 3-4. Further, the DMM recommends that the bid cap for Adjustment Bids used in the Day-Ahead and Hour-Ahead Congestion Management markets also be increased to $400/MWh, but that the bid cap for capacity bids in the Ancillary Services markets remain at $250/MWh. *Id.* at 5.

As explained in a CAISO memorandum dated December 16, 2005 to the CAISO Governing Board ("Board") concerning the proposed increase of the real-time Energy market bid cap ("CAISO Management Memorandum," provided as Attachment C to the instant filing), the CAISO has also received limited stakeholder comments in support of a bid cap increase, although stakeholders supported different forms of a bid cap increase.[5]

The CAISO was originally considering an increase to the level of the current "soft" bid cap for Energy bids and Adjustment Bids. The CAISO determined, however, that the increased bid cap should be a hard cap, consistent with the Commission's own directive to replace the current soft bid cap with a "hard" bid cap when the CAISO's MRTU market design is implemented. *California Independent System Operator Corp.*, 112 FERC ¶ 61,013, at P 104 (2005). Moving to a hard cap at this time will facilitate the transition to the $500/MWh energy bid cap scheduled to be implemented with the CAISO's new market design in 2007.

As explained in the Board resolution provided as Attachment F to the instant filing, the Board approved the increase of the bid cap to a $400/MWh hard cap for real-time Energy bids and Adjustment Bids at its December 16, 2005 meeting.

II. PROPOSED CHANGES

For the reasons discussed above, the CAISO proposes to modify Section 28.1.2 of the CAISO Tariff to replace the current $250/MWh soft bid cap on real-time Energy bids and Adjustment Bids with a $400/MWh hard cap. The CAISO does not propose any change to the current bid cap of $250/MWh that applies to capacity bids submitted in the CAISO's Ancillary Services markets. The CAISO

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5 Stakeholders submitted the following comments: the City of Anaheim indicated that it would not oppose raising the bid cap to $400/MWh; Southern California Edison Company stated that it would not oppose raising the bid cap to $400/MWh, if the CAISO would agree to reconsider the bid cap level in the event that market conditions change significantly, thus justifying a lower bid cap level; APS Energy Services, Constellation NewEnergy, and Strategic Energy stated that they support a $1,000/MWh hard cap for Energy bids, and Duke Energy Services recommended that the CAISO increase the bid cap to the Commission-approved MRTU bid cap level of $500/MWh. CAISO Management Memorandum at 2-3.

also proposes conforming changes to other provisions of the CAISO Tariff, including the Settlement and Billing Protocol.

The CAISO notes that it only has the authority, pursuant to Section 205 of the FPA, to make the instant filing to modify the bid cap in its own Tariff. The CAISO does not have the authority to submit a Section 205 filing to make changes to the $250/MWh bid cap that is in effect in the rest of the West.

III. EFFECTIVE DATE, REQUEST FOR EXPEDITED TARIFF PROCEDURES, AND REQUEST FOR SHORTENED COMMENT PERIOD

The CAISO respectfully requests, pursuant to Section 35.11 of the Commission's regulations, 18 C.F.R. § 35.11, that the Commission waive its notice requirements for Amendment No. 73, accept Amendment No. 73 for filing, and permit it to become effective on January 1, 2006 or as soon thereafter as possible. Good cause exists for granting this waiver. Acceptance of Amendment No. 73 effective as of that date will permit the California energy markets to realize the benefits described above as quickly as possible to address the substantial increase in natural gas prices that may well occur during the winter of 2005-2006. Making the change effective as of the start of the next calendar month will facilitate implementation of the bid cap change in the CAISO settlements process and will permit interested stakeholders time to comment on this proposal on an expedited basis. Granting the requested waiver, therefore, is appropriate.

In order to permit Amendment No. 73 to become effective on January 1, 2006 or as soon thereafter as possible, the CAISO requests expedited tariff revision procedures pursuant to the Commission's Expedited Tariff Revisions Guidance Order. In that Guidance Order, the Commission explained that it was providing a process by which it could promptly revise certain tariff revisions. Expedited Tariff Revisions Guidance Order at P 1. The Commission stated that a tariff revision submitted by a regional transmission organization ("RTO") or independent system operator ("ISO") pursuant to Section 205 of the FPA justifies the use of expedited tariff revision procedures by the Commission if the flaw that the revision is intended to remedy meets the following criteria:

(1) it materially adversely impacts the market (due to the unanticipated workings of the tariff or unanticipated actions by market participants);

(2) it requires prompt action to prospectively revise the tariff to remove the ability to cause such material adverse impacts; and

(3) it is susceptible to a clear-cut revision or interim tariff revision or market rule.

Id. at P 2. Amendment No. 73 satisfies these criteria. It is intended to remedy the risk that the CAISO real-time Energy market may not be able to attract sufficient supply bids to maintain system reliability, particularly from resources outside of the CAISO Control Area due to significant increases in generation variable operation costs. This risk will (1) materially and adversely impact the market because the current bid cap level, which was implemented in October 2002, does not take into account (and could not reasonably have taken into account) the substantially higher natural gas prices that may arise during the winter of 2005-2006. The risk that these costs could reduce the amount of supply offered to the CAISO real-time Energy market (2) requires prompt action to prospectively revise the CAISO Tariff to, *inter alia*, provide greater incentives for generation owners to maintain their units at a high level of availability, which will mitigate the risk of experiencing a forced outage during critical peak load hours. Further, the risk (3) is susceptible to the clear-cut revisions to the CAISO Tariff described in Section II, above.

The Expedited Tariff Revisions Guidance Order (at P 2) requires that the RTO or ISO post the filing on its website and send an e-mail notification to each market participant. Coincident with this filing, the CAISO is posting Amendment No. 73 on the CAISO's web site and has sent the attached market notice (provided as Attachment G to the instant filing) to each Market Participant. In addition, the CAISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, the California Electricity Oversight Board, and all parties with effective Scheduling Coordinator Service Agreements under the CAISO Tariff. The CAISO has also served the instant filing on the service lists for Docket Nos. ER02-1656 and EL01-68.[6]

In addition, the CAISO respectfully requests a shortened comment period for Amendment No. 73. The Expedited Tariff Revisions Guidance Order explains that the Commission will "expeditiously determine whether the reasons presented warrant expedited treatment," and if they do warrant expedited treatment, the Commission will promptly issue a notice and establish an expedited comment period from the date of the notice.[7] For the reasons explained above,

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[6] Docket Nos. ER02-1656 and EL01-68 were the dockets in which the Commission issued the July 17, 2002 Order and the October 11, 2002 Order establishing the current $250/MWh soft bid cap as discussed in Section I, above.

[7] Expedited Tariff Revisions Guidance Order at P 4. The Expedited Tariff Revisions Guidance Order (at P 4 n.4) states that the Commission expects that, in three to five business days, it would issue a notice that establishes an expedited comment period.

Amendment No. 73 warrants expedited treatment. Therefore, an expedited comment period is justified. The CAISO requests a comment date of December 28, 2005. This will allow the Commission to issue an order on Amendment No. 73 prior to the effective date requested by the CAISO. In addition, since the CAISO is e-mailing notice of Amendment 73 to all CAISO Market Participants, affected parties will be on notice as of today that the CAISO has requested an expedited comment period. Even with the forthcoming holiday period, this process should provide interested parties with sufficient time to comment on the filing.

IV. 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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V. ATTACHMENTS

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

Attachment A	Revised CAISO Tariff sheets that incorporate the proposed changes described above
Attachment B	The proposed changes to the CAISO Tariff shown in black-line format
Attachment C	The CAISO Management Memorandum
Attachment D	The MSC Recommendation Paper

Attachment E	The DMM Memorandum
Attachment F	The December 16, 2005 Board resolution
Attachment G	The December 21, 2005 market notice concerning Amendment No. 73

VI. CONCLUSION

For all the foregoing reasons, the Commission should accept Amendment No. 73 to become effective January 1, 2006 or as soon thereafter as possible. Please feel free to contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

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ATTACHMENT A

relevant Resource-Specific Settlement Interval Ex Post Price and 2) the resource's Energy Bid cost for each Settlement Interval. Bid cost recovery payment will be based on Settlement Intervals in which the resource: 1) did not recover its Energy Bid costs, and 2) generated or consumed an amount of Energy resulting from any Dispatch Instructions pursuant to Section 2.5.22. These Settlement Intervals will be netted against all Settlement Intervals in which the Instructed Imbalance Energy payments to the resource exceeded its Energy Bid costs. The resulting total bid cost recovery payment is then divided equally amongst the same Settlement Intervals to yield a per-Settlement Interval bid cost recovery payment. Energy Bid cost recovery associated with Residual Energy as provided for in Section 2.5.22.6.4 shall be based on the Energy Bids for the previous or next operating hour, whichever the case may be, upon which the Dispatch Instruction was based.

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section 2.5.23.3.7.6 and collected in accordance with Section 2.5.23.3.7.1.

11.2.4.2.2 Allocation of Above-MCP Costs For Accepted Bids

For each Settlement Interval, the at or below-MCP costs incurred as a result of accepted bids in the ISO Imbalance Energy Markets shall be allocated in accordance with 11.2.4.1. Allocation of above-MCP costs for accepted bids in the ISO Imbalance Energy Markets shall be in accordance with this Section 11.2.4.2.2 as follows.

11.2.4.2.2.1 Allocation of Bid Costs Above MCP

For each Settlement Interval, costs that are above the MCP, incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement shall which this Section 27 shall cease to apply, which date shall not be less than seven (7) days after the Notice of Full-Scale Operations is posted.

27.2 For so long as this Section 27.2 remains in effect, Scheduling Coordinators shall continue to be allowed to specify Adjustment Bids for Dispatchable Loads and exports, conditioned on the rule that the last segment of the Adjustment Bid (i.e., the maximum MW value) must equal the preferred MW operating point specified for the Dispatchable Load or export.

28. RULES LIMITING CERTAIN ENERGY AND ANCILLARY SERVICE BIDS

28.1 Damage Control Bid Cap

28.1 Notwithstanding any other provision of this ISO Tariff, Damage Control Bid Cap provisions of Section 28.1.2 and 28.1.3 shall apply to the ISO's Energy and Ancillary Service capacity markets.

28.1.2 **Maximum Bid Levels.** The maximum bid level for bids in the ISO's Energy markets, and the maximum bid level applicable to Adjustment Bids used in the ISO's Congestion Management markets, shall be $400/MWh. Notwithstanding any provision in this ISO Tariff to the contrary, the ISO shall not accept Energy bids or Adjustment Bids in excess of $400/MWh.

The maximum bid level in the ISO's Ancillary Service capacity markets shall be $250/MWh. Market Participants may submit bids in the ISO's Ancillary Service capacity markets above $250/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.

Second, any remaining unallocated costs shall be reduced pursuant to Section 11.2.4.1.2.

Third, any remaining unallocated costs shall be allocated amongst all Scheduling Coordinators in that Settlement Interval pro rata based on their metered Demand, including exports.

A Scheduling Coordinator shall be exempt from the first allocation step of costs that are above the MCP in a Settlement Interval if the Scheduling Coordinator has sufficient incremental Energy bids from physically available resources in the Imbalance Energy market to cover its Net Negative Uninstructed Deviation in the given Settlement Interval and the prices of such Energy bids do not exceed the applicable Maximum Bid Level as set forth in Section 28.1.2 of this Tariff.

11.2.4.2.2.2 Allocation of Bid Costs Above-MCP Pursuant to Section 11.2.4.1.1.1

For each Settlement Interval, the total unrecovered costs pursuant to Section 11.2.4.1.1.1 that are above the MCP and below the Maximum Bid Level as set forth in Section 28.1.2 of this tariff for each Trading Day will be allocated pro-rata to each Scheduling Coordinator based on its metered Demand. For a Scheduling Coordinator of an MSS Operator that has elected to follow Load, allocation of such unrecovered costs will be based on net metered Demand.

11.2.4.3 Unaccounted For Energy (UFE)

For settlement purposes, UFE is treated as Imbalance Energy. For each Settlement Interval, the ISO will calculate UFE on the ISO Controlled Grid, for each utility Service Area for which separate UFE calculation is performed. The UFE will be settled as Imbalance Energy at the Zonal Settlement Interval Ex Post Price. UFE attributable to meter measurement errors, load profile errors, Energy theft, and distribution loss deviations will be allocated to each Scheduling Coordinator based on the ratio of their metered Demand (including exports to neighboring Control Areas) within the relevant utility Service Area to total metered Demand within the utility Service Area.

which this Section 27 shall cease to apply, which date shall not be less than seven (7) days after the Notice of Full-Scale Operations is posted.

27.2 For so long as this Section 27.2 remains in effect, Scheduling Coordinators shall continue to be allowed to specify Adjustment Bids for Dispatchable Loads and exports, conditioned on the rule that the last segment of the Adjustment Bid (i.e., the maximum MW value) must equal the preferred MW operating point specified for the Dispatchable Load or export.

28. RULES LIMITING CERTAIN ENERGY AND ANCILLARY SERVICE BIDS

28.1 Damage Control Bid Cap

28.1 Notwithstanding any other provision of this ISO Tariff, Damage Control Bid Cap provisions of Section 28.1.2 and 28.1.3 shall apply to the ISO's Energy and Ancillary Service capacity markets.

28.1.2 **Maximum Bid Levels.** The maximum bid level for bids in the ISO's Energy markets, and the maximum bid level applicable to Adjustment Bids used in the ISO's Congestion Management markets, shall be $400/MWh. Notwithstanding any provision in this ISO Tariff to the contrary, the ISO shall not accept Energy bids or Adjustment Bids in excess of $400/MWh.

The maximum bid level in the ISO's Ancillary Service capacity markets shall be $250/MWh. Market Participants may submit bids in the ISO's Ancillary Service capacity markets above $250/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

   A reference level for each bid segment shall be calculated each day for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

   1. Excluding proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. Accepted and justified bids above the applicable cap, as set forth in Section 28.1.2 of this Tariff, will be included in the calculation of reference prices.
   2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).
   3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO Market Clearing Prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be as follows:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of an increase of 200 percent or $50 per MWh in the projected Hourly Ex Post Price at any location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

For Energy Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion: if the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

Accepted and justified bids above the applicable cap, as set forth in Section 28.1.2 of this Tariff, will not be eligible to set the Market Clearing Price. Such bids shall be included in the Market Impact test, however, and, for purposes of this test only, shall be assumed to be eligible to set the Market Clearing Price.

3.2.2 Price Impact Analysis

3.2.2.1 Bids to be Dispatched as Imbalance Energy.

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in projected Hourly Ex Post Prices as a result of simultaneously setting all such bids to their Reference Levels. If a change in the projected Hourly Ex Post Price exceeds the Impact threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators

Standard Ramping Energy is Energy associated with a Standard Ramp and shall be deemed delivered and settled at a price of zero dollars per MWh.

Ramping Energy Deviation is Energy produced or consumed due to hourly schedule changes in excess of Standard Ramping Energy and shall be paid or charged, as the case may be, at a Resource-Specific Settlement Interval Ex Post Price calculated using the applicable Dispatch Interval Ex Post Prices as described in this Appendix D 2.4. For Scheduling Coordinators scheduling a MSS that has elected to follow its Load, this Ramping Energy Deviation will account for the units following Load.

Ramping Energy Deviation shall be settled as an explicit component of Instructed Imbalance Energy for each resource *i* in Dispatch Interval *k* of Settlement Interval *o* for hour *h*, and calculated as follows:

$$REDC_{i,h,o} = \left(\sum_{1}^{k} RED_{i,h,o,k}\right) * STLMT\_PRICE_{i,h,o}$$

Hourly Predispatched energy from System Resources is an explicit component of Instructed Imbalance Energy for each interchange resource *i* in Dispatch Interval *k* of Settlement Interval *o* for hour *h*, and settled pursuant to Sections 11.2.4.1.1 and 11.2.4.1.1.2 of the ISO Tariff. The settlement calculation is as follows:

If (

$(COST\_AT\_STLMT\_PRICE_{i,h,o} >= 0$

And

$BID\_COST_{i,h,o} >=0)$

Then

$$IIEC\_PREDISPATCH_{i,h,o} = (-1) *$$

$$min(COST\_AT\_STLMT\_PRICE_{i,h,o}, BID\_COST_{i,h,o})$$

Else

$$IIEC\_PREDISPATCH_{i,h,o} = (-1) * BID\_COST_{i,h,o}$$

Where

$$COST\_AT\_STLMT\_PRICE_{i,h,o} =$$

$$\left(\sum_{1}^{k} IIE\_PREDISPATCH_{i,h,o,k}\right) * STLMT\_PRICE_{i,h,o}$$

$$BID\_COST_{i,h,o} =$$

$$\sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m} * IIE\_PRICE_{i,h,o,k,m}$$

for the portion of incremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ limited to the Bid Floor when $IIE\_PRICE_{i,h,o,k,m}$.is less than the Bid Floor.

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for the portion of incremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ limited to the Bid Floor when $IIE\_PRICE_{i,h,o,k,m}$ is less than the Bid Floor.

D 2.6.4 Allocation of Unrecovered Cost Payments for Hourly Pre-dispatched System Resources

For each Settlement Interval *o*, the total uplift payments ($PREDISPATCH\_PMT_{i,h,o}$) for all hourly pre-dispatched System Resources will be included in the Excess Cost Payments to be allocated to a Scheduling Coordinator's Net Negative Deviation through allocation of excess costs and/or ISO metered Demand through excess cost neutrality allocation.

D 2.7 Transmission Loss Obligation

The transmission loss obligation charge shall be determined as follows:
For Generators:

$$TL_{i,h,o} = ME_{i,h,o} * (1 - GMMa_h)$$

For System Resources, the transmission loss obligation shall be determined as follows:

D 3.2 **COST_AT_STLMT_PRICE$_{i,h,o}$ - $/MWh**

The sum of all dollar amounts from each dispatched bid segment for Energy quantities settled at the Resource-Specific Ex Post Price, for resource i during Settlement Interval o of hour h, and limited to those bid segments with Energy Bid prices below the Maximum Bid Level.

D 3.3 **BID_COST$_{i,h,o}$ - $/MWh**

The sum of all dollar amounts from each dispatched bid portion of Energy quantities settled at the maximum of either the corresponding Energy Bid price for those bids with Energy Bid prices below the Maximum Bid Level or the Bid Floor, for resource i during Settlement Interval o during hour h.

D 3.4 **[Not Used]**

D 3.5 **IIE_PREDISPATCH_FOR_SEGMENT$_{i,h,o,k,m}$ - MWh**

The pre-dispatched Energy for resource i during Dispatch Interval k of Settlement Interval o of hour h for bid segment m.

D 3.6 **[Not Used]**

D 3.6.1 **[Not Used]**

D 3.6.2 **[Not Used]**

D 3.6.3 **[Not Used]**

D 3.7 **$G_{a,i,j,h,o}$ – MWh**

The total actual metered Generation of Generator i in Zone j during Settlement Interval o during Settlement Period h.

D 3.8 **[Not Used]**

ATTACHMENT B

11.2.4.1.1.1 Bid Cost Recovery for Generating Units, System Units, Dynamically Scheduled System Resources, and Curtailable Demand.

The ISO shall determine, for each Trading Day, for each Generating Unit, System Unit, dynamically scheduled System Resource, and Curtailable Demand, Dispatched in the Real Time Market pursuant to Section 2.5.22, whether there exists a surplus or deficit in that resource's recovery of its Energy Bid costs, that are less than or equal to the Maximum Bid Level, through Instructed Imbalance Energy credits, as set forth in Section 11.2.4.1.1. This determination of market revenue surplus or deficit shall be calculated as the difference between: 1) the Instructed Imbalance Energy payment as based on the relevant Resource-Specific Settlement Interval Ex Post Price and 2) the resource's Energy Bid cost for each Settlement Interval. Bid cost recovery payment will be based on Settlement Intervals in which the resource: 1) did not recover its Energy Bid costs, and 2) generated or consumed an amount of Energy resulting from any Dispatch Instructions pursuant to Section 2.5.22. These Settlement Intervals will be netted against all Settlement Intervals in which the Instructed Imbalance Energy payments to the resource exceeded its Energy Bid costs. The resulting total bid cost recovery payment is then divided equally amongst the same Settlement Intervals to yield a per-Settlement Interval bid cost recovery payment. ~~Payments for unrecovered bid costs for portions of Energy associated with bids above the Maximum Bid Level will not be netted with other surpluses or deficits and are subject to recall if the such bids above have not been adequately justified pursuant to Section 28.1.2.~~ Energy Bid cost recovery associated with Residual Energy as provided for in Section 2.5.22.6.4 shall be based on the Energy Bids for the previous or next operating hour, whichever the case may be, upon which the Dispatch Instruction was based.

* * *

11.2.4.2.2 Allocation of Above-MCP Costs For Accepted Bids

For each Settlement Interval, the at or below-MCP costs incurred as a result of accepted bids in the ISO Imbalance Energy Markets shall be allocated in accordance with 11.2.4.1. Allocation of above-MCP costs for accepted bids in the ISO Imbalance Energy Markets shall be in accordance with this Section 11.2.4.2.2 as follows.

11.2.4.2.2.1 Allocation of Bid Costs Above ~~the Maximum Bid Level~~MCP

For each Settlement Interval, costs that are ~~both~~ above the MCP ~~and above the Maximum Bid Level~~, incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement shall be charged to Scheduling Coordinators as follows in a three-step process. First, each Scheduling Coordinator's charge shall be the lesser of:

(a) the pro rata share of the total costs that are ~~both~~ above the MCP ~~and above the Maximum Bid Level~~ based upon the ratio of each Scheduling Coordinator's Net Negative Uninstructed Deviations to the total system Net Negative Uninstructed Deviations; or

(b) the amount obtained by multiplying the Scheduling Coordinator's Net Negative Uninstructed Deviation for each Settlement Interval and a weighted average price. The weighted average price is equal to the total costs that are ~~both~~ above the MCP ~~and above the Maximum Bid Level~~ divided by the MWh delivered as a result of ISO instructions with a cost component above the MCP.

Second, any remaining unallocated costs shall be reduced pursuant to Section 11.2.4.1.2.

Third, any remaining unallocated costs shall be allocated amongst all Scheduling Coordinators in that Settlement Interval pro rata based on their metered Demand, including exports.

A Scheduling Coordinator shall be exempt from the first allocation step of costs that are ~~both~~ above the MCP ~~and above the Maximum Bid Level~~ in a Settlement Interval if the Scheduling Coordinator has sufficient incremental Energy bids from physically available resources in the Imbalance Energy market to cover its Net Negative Uninstructed Deviation in the given Settlement Interval and the prices of such Energy bids do not exceed the applicable Maximum Bid Level as set forth in Section 28.1.2 of this Tariff.

11.2.4.2.2.2 Allocation of Bid Costs Above-MCP Pursuant to Section 11.2.4.1.1.1 ~~and Below the Maximum Bid Level~~

For each Settlement Interval, the total unrecovered costs pursuant to Section 11.2.4.1.1.1 that are above the MCP and below the Maximum Bid Level as set forth in Section 28.1.2 of this tariff for each Trading

Day will be allocated pro-rata to each Scheduling Coordinator based on its metered Demand. For a Scheduling Coordinator of an MSS Operator that has elected to follow Load, allocation of such unrecovered costs will be based on net metered Demand.

* * *

28.1 Damage Control Bid Cap

28.1 Notwithstanding any other provision of this ISO Tariff, Damage Control Bid Cap provisions of Section 28.1.2 and 28.1.3 shall apply to the ISO's Energy and Ancillary Service capacity markets.

28.1.2 **Maximum Bid Levels.** The maximum bid level for bids in the ISO's Energy markets, and the maximum bid level applicable to Adjustment Bids used in the ISO's Congestion Management markets, shall be $400/MWh. Notwithstanding any provision in this ISO Tariff to the contrary, the ISO shall not accept Energy bids or Adjustment Bids in excess of $400/MWh.

The maximum bid level in the ISO's Ancillary Service capacity markets shall be $250/MWh. Market Participants may submit bids in the ISO's Ancillary Service capacity markets above $250/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.

* * *

<u>ISO Market Monitoring and Information Protocol (MMIP)</u>

APPENDIX A

ISO Market Monitoring Plan

Market Mitigation Measures

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

A reference level for each bid segment shall be calculated each day for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

1. Excluding proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. Accepted and justified bids above the applicable ~~soft~~ cap, as set forth in Section 28.1.2 of this Tariff, will be included in the calculation of reference prices.
2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly

as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.
4. The mean of the Economic Market Clearing Prices for the units' relevant location (Zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or
5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:
   i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or
   ii. an appropriate average of competitive bids of one or more similar Electric Facilities.

(b) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO Market Clearing Prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be as follows:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of an increase of 200 percent or $50 per MWh in the projected Hourly Ex Post Price at any location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

For Energy Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion: if the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

Accepted and justified bids above the applicable ~~soft~~ cap, as set forth in Section 28.1.2 of this Tariff, will not be eligible to set the Market Clearing Price. Such bids shall be included in the Market Impact test, however, and, for purposes of this test only, shall be assumed to be eligible to set the Market Clearing Price.

SETTLEMENT AND BILLING PROTOCOL

APPENDIX D

IMBALANCE ENERGY CHARGE COMPUTATION

* * *

D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators

Standard Ramping Energy is Energy associated with a Standard Ramp and shall be deemed delivered and settled at a price of zero dollars per MWh.

Ramping Energy Deviation is Energy produced or consumed due to hourly schedule changes in excess of Standard Ramping Energy and shall be paid or charged, as the case may be, at a Resource-Specific Settlement Interval Ex Post Price calculated using the applicable Dispatch Interval Ex Post Prices as described in this Appendix D 2.4. For Scheduling Coordinators scheduling a MSS that has elected to follow its Load, this Ramping Energy Deviation will account for the units following Load.

Ramping Energy Deviation shall be settled as an explicit component of Instructed Imbalance Energy for each resource *i* in Dispatch Interval *k* of Settlement Interval *o* for hour *h*, and calculated as follows:

$$REDC_{i,h,o} = \left(\sum_{1}^{k} RED_{i,h,o,k} \right) * STLMT\_PRICE_{i,h,o}$$

Hourly Predispatched energy from System Resources is an explicit component of Instructed Imbalance Energy for each interchange resource *i* in Dispatch Interval *k* of Settlement Interval *o* for hour *h*, and settled pursuant to Sections 11.2.4.1.1 and 11.2.4.1.1.2 of the ISO Tariff. The settlement calculation is as follows:

If (

$(COST\_AT\_STLMT\_PRICE_{i,h,o} >= 0$

And

$BID\_COST_{i,h,o} >= 0)$

Then

$$\cancel{IIEC\_PREDISPATCH_{i,h,o} = (-1) *}$$

$$\cancel{[min(COST\_AT\_STLMT\_PRICE_{i,h,o}, BID\_COST_{i,h,o})}$$

$$\cancel{+ (STLMT\_PRICE_{i,h,o} * PRE\_DISP\_ABC\_BQ_{i,h,o})]}$$

$$IIEC\_PREDISPATCH_{i,h,o} = (-1) *$$

$$\underline{min(COST\_AT\_STLMT\_PRICE_{i,h,o}, BID\_COST_{i,h,o})}$$

Else

$IIEC\_PREDISPATCH_{i,h,o} = (-1) * \underline{BID\_COST_{i,h,o}}$

$\cancel{[BID\_COST_{i,h,o} + (STLMT\_PRICE_{i,h,o} * PRE\_DISP\_ABC\_BQ_{i,h,o})]}$

Where

$COST\_AT\_STLMT\_PRICE_{i,h,o} =$

$$\left(\sum_{1}^{k} IIE\_PREDISPATCH_{i,h,o,k}\right) * STLMT\_PRICE_{i,h,o}$$

$BID\_COST_{i,h,o} =$

$$\sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m} * IIE\_PRICE_{i,h,o,k,m}$$

for the portion of incremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ limited to the Bid Floor when $IIE\_PRICE_{i,h,o,k,m}$.is less than the Bid Floor.

))

~~where~~

~~$PRE\_DISP\_ABC\_BQ_{i,h,o}$ =~~

$\cancel{\sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m}}$ ~~for the portion of~~

~~incremental energy bid segments with $IIE\_PRICEi_{,h,o,k,m}$ greater than the Maximum Bid Level.~~

The amount of Instructed Imbalance Energy that will be deemed delivered in each Dispatch Interval will be based on Dispatch Instructions, as provided for in Section 2.5.22.6, and Final Hour-Ahead Schedules. The amount of Instructed Imbalance Energy to be settled in a Settlement Interval will be equal to the sum of all Instructed Imbalance Energy for all Dispatch Intervals within the relevant Settlement Interval. Instructed Imbalance Energy for each Settlement Interval shall be settled at the relevant Resource Specific Settlement Interval Ex Post Price. Generating Units, Participating Loads, and System Units may be eligible to recover their Energy Bid costs in accordance with Section 11.2.4.1.1.1. Instructed Imbalance Energy from System Resources shall be settled in accordance with Section 11.2.4.1.1.2.

The Instructed Imbalance Energy amount for each resource *i* in Settlement Interval *o* for hour *h* shall be determined as follows:

$$IIEC_{i,h,o} = (-1) * \begin{pmatrix} \sum_{1}^{k}\sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} \\ + \sum_{1}^{k} IIE\_RERATE_{i,h,o,k} + \sum_{1}^{k} IIE\_ML_{i,h,o,k} \end{pmatrix} * STLMT\_PRICE_{i,h,o}$$

$$+ \; IIEC\_OOS_{i,h,o} \; + \; REDC_{i,h,o} + IIEC\_REG_{i,h,o} + IIEC\_PREDISPATCH_{i,h,o}$$

Uninstructed Imbalance Energy is Imbalance Energy due to non-compliance with a Dispatch Instruction and shall be settled as provided for in SABP Appendix D Section 2.1.1.

* * *

~~**D 2.6.5**~~ ~~**Excess Cost Payments for Instructed Incremental Energy Bids above the Maximum Bid Level**~~

~~Incremental Instructed Imbalance Energy above the Maximum Bid Level will receive an additional Excess Cost Payment subject to operating within a resource's Tolerance Band.~~

~~Excess cost payments are calculated as follows:~~

$$\cancel{EXCESS\_COST_{i,h,o} = \left[\left(\sum_{1}^{k}\sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m}\right) * STLMT\_PRICE_{i,h,o} - BID\_COST_{i,h,o} - BID\_COST\_RIE_{i,h,o}\right] * PERF\_STAT_{i,h,o}}$$

~~for the portion of energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ and $RIE\_PRICE_{i,h,o,k,m}$ greater than the Maximum Bid Level.~~

* * *

D 3 **Meaning of terms in the formulae**

D 3.1 **[Not Used]**

D 3.2 **COST_AT_STLMT_PRICE$_{i,h,o}$ - $/MWh**

The sum of all dollar amounts from each dispatched bid segment for Energy quantities settled at the Resource-Specific Ex Post Price, for resource i during Settlement Interval o of hour h, and limited to those bid segments with Energy Bid prices below the Maximum Bid Level.

D 3.3 **BID_COST$_{i,h,o}$ - $/MWh**

The sum of all dollar amounts from each dispatched bid portion of Energy quantities settled at the maximum of either the corresponding Energy Bid price for those bids with Energy Bid prices below the Maximum Bid Level or the Bid Floor, for resource i during Settlement Interval o during hour h.

D 3.4 **~~PRE_DISP_ABC_BQ$_{i,h,o}$ – MWh~~[Not Used]**

~~The pre-dispatched Energy from all Energy Bids with any Energy Bid price above the Maximum Bid Level, for resource i during Settlement Interval o during hour h.~~

* * *

ATTACHMENT C

CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Greg Cook, Manager, Tariff and Regulatory Policy

cc: ISO Officers

Date: December 16, 2005

Re: **Approval to Raise Real-time Energy Market Bid cap from $250/MWh to $400/MWh**

This Memorandum requires Board action.

Background

Recently, there have been significant changes in market conditions including an increase in natural gas prices, the fuel source for the majority of generation used to meet California load. Concern that the current level of the bid cap may constrain the ISO's ability to acquire sufficient power in real time in certain circumstances caused the ISO Department of Market Monitoring (DMM) to request a re-examination of the level of the real-time energy market Damage Control Bid Cap. On November 9, 2005, in response to a request from DMM, the ISO's Market Surveillance Committee (MSC) provided an Opinion on raising the levels of the Damage Control Bid Cap on the real-time energy market. The MSC supports raising the bid cap to $400/MWh based on their primary concern that generation unit-level variable costs could approach or rise above the current cap level of $250/MWh due to high and volatile natural gas fuel costs. The MSC also contends that the $250/MWh bid cap established in 2002 would be comparable to a $400/MWh cap under current natural gas prices.

Analysis

Market conditions have changed significantly since the current $250/MWh bid cap was implemented as part the Phase 1a market redesign elements on October 1, 2002. The California IOUs have indicated that they have locked in their forecast energy requirements through summer 2006 through long-term forward energy contracts that are set at a fixed price or a price indexed to natural gas prices. This leaves the majority of the load in the ISO control area with very small cost exposure to spot market energy prices and shifts the spot market price risk to the supply side of the market, which provides suppliers with incentives to keep spot market prices low. Over the past year, the ISO real-time imbalance market has comprised less than 2 percent of the total wholesale energy requirements in the ISO's control area. The current $250/MWh bid cap on the California ISO's real-time energy market was most recently established in October 2002 when natural gas prices were between $3 and $4/mmbtu. In recent months, concerns over tight natural gas supply have resulted in very high and volatile natural gas prices throughout the country. Natural gas spot prices in California recently reached as high as $12/mmbtu and have recently been extremely volatile. Natural gas prices could easily rebound higher during the critical winter heating demand months (December-March). Given these significant changes in market conditions, ISO Management is recommending that the real-time energy market Damage Control Bid Cap be increased from $250/MWh to $400/MWh.

Raising the bid cap under current market conditions would provide several significant benefits to the California energy markets.

- A higher bid cap would also provide several reliability benefits critical to maintaining reliable grid operation given the tight supply margins forecast for next summer.
    1. Attract resources to offer supply to the real-time imbalance energy market, particularly from intertie resources that are not required to bid into the ISO market.
    2. It would provide greater incentives for generator owners to maintain their units at a high level of availability so they mitigate the risk of experiencing a forced outage during a critical peak load hours.
    3. It would provide greater incentives for further development of demand response programs such as real-time pricing. Such demand programs would reduce reliance on high cost, environmentally unfriendly combustion turbines during critical peak demand hours and increase supply margins during peak load periods.
    4. It would promote reliability by providing greater fixed cost recovery for generating units during high demand periods when supply margins are tight and prices are at or near the bid cap. Several generating units in California are at risk of retirement due to insufficient fixed cost recovery. Moreover, some new generating units in the CAISO Control Area do not have long-term power contracts and a higher spot price during critical peak periods will help to make these units more economically viable.
    5. Should gas prices escalate significantly over the winter months in response to high gas heating demand or supply disruptions, a higher cap would not discourage suppliers from selling into the California real-time energy market where they may not be able to recover their production costs. A higher cap would also provide a greater incentive to suppliers with options of selling their output in the western bilateral short-term energy markets to provide real-time energy bids to the ISO to meet system balancing needs.
- A higher bid cap would provide greater incentives for the LSEs to continue to minimize their spot market exposure by signing additional long-term power contracts.
- Finally, increasing the cap to $400/MWh would also provide a measured transition to the $500/MWh energy bid cap scheduled to be invoked with the California ISO's new market design in February 2007. ISO Management is not proposing to change the current Ancillary Services Markets bid cap of $250/MW that will continue under the new market design.

Stakeholder Comments

The ISO and MSC received limited comments from stakeholders on the issue of raising the bid cap. The following provides a brief summary of the comments provided:

Southern California Edison. In comments to the MSC, SCE agreed that given the current high natural gas prices, it is appropriate for the ISO to review the bid cap and develop a plan of action in the event that marginal production costs for the typical units operating could rise above $250/MWh. SCE proposed a mechanism that would adjust the bid cap based on the level of bid week natural gas prices at Malin and the SoCal border. In subsequent discussions with the ISO, SCE indicated that they would not oppose raising the cap to $400/MWh if the ISO would agree to reconsider the cap level in the event that market conditions change significantly that would justify a lower bid cap level.

City of Anaheim. The City of Anaheim provided initial comments to the MSC raising concerns that the current $250/MWh cap was sufficient for generating units to cover their operating costs even when natural gas prices are in the $11 to $12/MMbtu range. Later, after further discussions with the ISO regarding their concerns, Anaheim indicated that they would not oppose raising the bid cap to $400/MWh.

APS Energy Services, Constellation NewEnergy and Strategic Energy. Electric Service Providers (ESPs) APS Energy Services, Constellation NewEnergy and Strategic Energy, who serve direct access customers in California, provided comments to the MSC stating that they are concerned that the current $250/MWh bid cap jeopardizes the ability of California to obtain sufficient energy to meet its needs in the coming months. They also commented that the current bid cap artificially constrains prices, creates shortages and discourages investment in California. These joint ESPs support a $1,000/MWh hard cap for energy bids to be implemented immediately which they argue would better reflect the realities of today's energy market and send a strong signal that California is moving toward a stable long-term energy environment that encourages infrastructure investment.

Duke Energy Services. Duke commented that they view the current $250/MWh cap as interim in nature and that the cap should not prevent generators from recovering their costs or preventing units from setting the market clearing price if market conditions such as high natural gas prices push energy offers above the damage control cap. Duke recommends that the ISO raise the bid cap to the FERC approved MRTU cap level of $500/MWh. Duke also recommended that the AMP price screen of $91.87/MWh be adjusted as well to be in line with current gas prices and that the 90 day look back period for setting the AMP reference level be shorted to a 7-day period.

Conclusion

The determination of whether to raise the bid cap is not a science, but a weighing of the relative risks of higher energy costs versus reliability risks associated with a cap that is too low. Given current market conditions, the ISO believes that the reliability risks far outweigh the cost risks associated with raising the bid cap. The ISO's real-time energy market has been stable for more than four years and the majority of the load in the ISO control area is hedged against spot market price risk. Moreover, local market power mitigation measures will remain in place to address potential market performance concerns related to infeasible schedules caused by congestion within the ISO's established congestion zones until the new market design is implemented in early 2007. The supply to demand balance is forecast to be tight for the summer of 2006, particularly in southern California. To maintain reliable system operation, the ISO will need to attract sufficient resources to the real-time imbalance energy market, particularly from intertie resources that are not required to bid into the ISO market. For these reasons, the California ISO is recommending that the real-time energy market bid cap be increased from $250/MWh to $400/MWh. The ISO will continue to closely monitor market performance and should market conditions change significantly, the ISO will revisit the appropriate level of the Damage Control Bid Cap.

Resolution

Based on the reasoning discussed above, ISO Management recommends that the Board adopt the following motion:

Moved, that the ISO Board of Governors:

Authorizes Management to file an Amendment to the ISO tariff with the Federal Energy Regulatory Commission to raise the current $250/MWh Damage Control Bid Cap for Real-time Energy Bids to $400/MWh. Any accepted bids above $400/MWh would not be eligible to set the Market Clearing Price and

would be subject to cost-justification and refund. ISO Management is also authorized to include in the Amendment an increase in the congestion management adjustment bid cap to $400/MWh. ISO Management will revisit the level of the bid cap whenever circumstances arise that are detrimental to market performance or reliable system operation.

ATTACHMENT D

Raising the Level of the Bid Cap on the Real-Time Energy Market in California

by

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

November 9, 2005

1. Introduction

We have been asked by the ISO management whether recent trends in natural gas prices justify raising the level of the bid cap on the real-time energy market in California. The present level of the bid cap was initially established in 1998 when the price of natural gas in California was between $2.00 per million BTU (MMBTU) and $3.00/MMBTU. Spot natural gas prices are currently fluctuating between $10/MMBTU and $12/MMBTU, which implies that reconsideration of the $250/MWh bid cap is necessary.

This opinion provides our recommendation for re-setting the level of the bid cap. In the process of preparing it we received written comments from the City of Anaheim, Southern California Edison, Duke Energy, and RTO Advisors (on behalf of APS Energy Services, Constellation NewEnergy and Strategic Energy). We have also discussed issues relating to re-setting the level of the bid cap at the September 22 Market Surveillance Committee meeting and received public comment from stakeholders. We are extremely grateful to stakeholders for their written comments and participation at the MSC meetings. Their perspectives on this very important issue were extremely helpful to us in formulating this opinion.

We conclude that the primary concern at the present time is the risk of generation unit-level variable costs approaching or rising above the cap level.[1] If gas prices rise further beyond their current range, there is a risk that the bid-cap will restrict electricity supplies to California. Rather than wait for natural gas prices to exceed some pre-specified value before increasing the bid cap, we believe that the likelihood of substantially higher natural gas prices during the winter of 2005 is sufficiently high to justify raising the bid cap at the present time. Given the relatively small amount of power now purchased at short-term market prices, we view the risk of supply shortfall to be a much more serious threat to California consumers than the potential cost consequences of increasing the bid cap. Raising the bid cap only in response to evidence of supply shortfalls at the current bid cap has significant reliability consequences. We do not believe that the "soft" nature of the current bid cap adequately addresses these risks.[2] The new level of the bid cap should be high enough to make it very unlikely that the ISO will need to increase the cap again before February of 2007, when the locational marginal pricing (LMP) market is scheduled to be implemented. If the current $250/MWh bid cap was appropriate for the natural gas prices that prevailed during 1998 and

[1] The degree to which energy revenues are to be relied upon for the recovery of fixed and capital costs of generation is the subject of ongoing resource adequacy proceedings. The final level of the bid cap beyond 2007 obviously should be influenced by the results of this proceeding.

[2] If market conditions are such that generation units in the California ISO control area can credibly justify variable costs above the current bid cap, under the "soft" cap those units are allowed to bid a price above $250/Mwh if they can demonstrate that their costs make such a bid necessary. This creates a situation in which heavy use of the soft cap contributes to market opaqueness and encourages generators to inflate their variable cost estimates.

1999, the bid cap should be increased to at least $400/MWh,considering the likely trajectory of natural gas prices this winter. Although our main concern is the reliability of the market if gas prices rise further above current levels, we feel that this possibility is likely enough that it would be advisable to raise the bid-cap now, rather than wait for conditions that may prove disruptive to the market.

2. Factors Determining Level of Bid Cap

Although economic theory provides limited guidance for setting the level of the bid cap, the trade-off in setting the level of cap is the ability to limit the unilateral market power exercised by suppliers against the risk that the cap will be set too low and artificially limit the supply of energy. Low bid caps also risk limiting the role of demand response in the short-term market and dull the incentive retailers have to enter into long-term fixed price contracts for energy and ancillary services. The risk of supply shortfalls has three dimensions. First, the cap may be set below the incremental costs of some generation units and be inadequate to attract supply into California in the short-term market. Second, the cap may be set above the incremental costs of all units but still too low to allow suppliers to recover fixed costs and therefore attract new investment to the California market. When genuine shortage conditions occur, prices should be allowed to reflect that scarcity in order to attract investment. Third, a cap that is effectively lower than neighboring regions could draw needed supply away from the local market when it is needed most.

It is very difficult to assess whether any hourly price-cap is set high enough to recover fixed costs and attract new investment. This is because investment decisions are based upon forecast average prices over long periods of time, and the ability of a given bid cap level to provide sufficient revenues depends largely upon how often market prices reach that price-cap. Because of the time lags in construction, we note that current cap levels will almost certainly not impact the level of *installed* capacity over the next summer, although too low of a bid cap may cause some existing high cost units to retire if they are unable to sign a long-term contract for their energy. Nevertheless, because California is in the process of developing a resource adequacy regime to take effect by June 2006, we conclude that policies about the current level of the bid cap should focus on the risks of near-term disruption--in other words, current policy should focus on the risk that the operating costs could rise close to or above the cap level.

From the perspective of short-term reliability, it is crucial that the west-wide bid cap exceed the variable cost of the higher cost units needed to meet the demand peaks in California. Because California is a net importer of electricity in virtually all hours of the year, setting the bid cap below this level runs the risk that a supplier needed to meet demand in California will be unable to cover the variable cost of producing the necessary electricity at a price equal to the bid cap. Consequently, this unit owner may decide not to supply the needed electricity to the California market. This inability to recover the variable cost of production is less of a concern under the current "soft" bid cap on the real-time market which allows a supplier to cost-justify bids in excess of the current $250/MWh bid cap. Yet we note that the more frequently such exemptions are made to the cap, the less credible the $250/MWh level becomes. Specifically, the more exemptions that are made, the more likely it will be that other firms will seek them. More importantly, extensive reliance on the soft-cap creates a two-tier payment structure, with expensive units paid as-bid above $250/MWh and less expensive units consigned to earning no more than $250. If these units are denied the ability to earn a legitimate market-clearing price above $250 in California, they will likely try to earn that price outside of California. Thus the application of the soft cap to some generation does not adequately ensure that enough suppliers, both inside and outside of California, will choose to sell into the California market.[3]

California's experience with the $150/MWh soft bid cap, implemented on January 1, 2001, demonstrates what can happen when the bid cap is set low enough for suppliers to credibly justify variable costs above the bid cap. It must be noted that implementation of this soft-cap ushered in the months with the highest wholesale electricity costs of the entire crisis period. A substantial amount of generation was impacted by the soft-cap, and the regulatory and bureaucratic machinations involved in enforcing it created very strong incentives to inflate costs. The disruptive effects spilled over from the electricity market to markets for natural gas and emissions credits.

For this reason, the bid cap should be set far enough above the incremental costs of the vast majority of generation units in the California ISO control area so that few, if any, unit owners can credibly justify bids in excess of this level. If the bid cap is set too low, suppliers may find it profitable to take actions to increase their apparent regulated variable costs so that their bid can exceed the bid cap. The ISO will have a difficult time preventing suppliers from taking these actions, because it is very difficult, if not impossible, for the ISO to determine a supplier's actual variable cost. Avoiding this incentive to inflate variable costs above $250/MWh in all hours by allowing a higher market-clearing price during some hours could result in lower wholesale energy costs under a higher bid cap.

The level of the bid cap is closely related to the extent of fixed-price forward contracting in a market. Higher levels of forward contracts reduce the exposure of load serving entities to price spikes in the short-term market. Thus, high levels of forward contracts are necessary under a high bid cap. On the other hand, forward contracts also help to ensure reliability under a low cap. If electricity demand outside of California is high enough to cause the spot price of electricity outside of California to rise above the bid cap, all suppliers in Western Electricity Coordinating Council (WECC) that do not have forward contract commitments to California LSEs can be expected to sell their electricity outside of California through multi-hour bilateral transactions that effectively pay prices higher than the current bid cap during some hours. These actions create significant reliability problems for the California ISO operators and increase the likelihood of supply shortfalls in California. Lower levels of forward contracting by California LSEs and direct access (DA) customers imply a greater risk that high spot prices outside of California result in insufficient energy being offered into the spot market in California at or below the bid cap.

Experience from other wholesale electricity markets does not provide clear recommendations for adjusting the bid cap as the level of forward contracting is reduced from 100% coverage. In addition, answering this question with any confidence requires knowledge of the fixed-price forward contract position of the major suppliers to the California market. The three major LSEs in California argue that a substantial fraction of the demand they expect to serve over the coming two to three years is covered by fixed-priced forward contracts for energy. For this reason, there is less of a concern that California consumers might be harmed by an increase in the bid cap.

Raising the bid cap significantly increases the incentive for final demand to become an active participant in the wholesale market. The potential for higher short-term prices under a higher bid

[3] Even if a $250 cap continued to be applied to the entire western market, there is concern that neighboring control areas could easily acquire energy at prices above that level through bilateral arrangements that effectively sell power above capped levels.

cap increases the benefits that consumers can realize from paying the hourly wholesale price for some fraction of their consumption each hour of the day. Increasing the amount of final demand able to respond to short-term price movements increases system reliability. It reduces the risk of a real-time supply shortfall, because higher short-term prices will not only increase the supply of electricity to California, but they will also reduce the real-time demand for electricity in California.

Therefore, it is very important for the California Public Utilities Commission (CPUC) to encourage more active demand-side participation. As we have previously noted, unless the CPUC encourages more active demand-side participation in the wholesale market by a substantial fraction of final demand, the net benefits, in terms of spot market efficiency and demand-side participation, of higher bid caps are likely to be limited.[4] There are substantial reliability and market efficiency benefits that can be realized by raising the bid cap if the CPUC allows more active demand-side participation in the wholesale market. A higher bid cap increases the incentive that retailers have to sign fixed-price long-term contracts. This higher bid cap also increases the incentive that these suppliers have to make their generation units available to the short-term market. If they do not supply their forward contract commitment in energy from their generation units, then they must purchase the remainder of the forward commitment from the short-term market at a price that can be as high as the bid cap. A higher bid cap also makes it more likely that suppliers located outside of California will be willing to keep their units available to sell energy into California.

There are also potential environmental benefits associated with a higher bid cap on the short-term energy market. To meet the demand peaks it is often necessary to operate high cost combustion turbine units located near California's major load centers. These units also have very high NOx emissions rates. Allowing a larger fraction of final demand to respond to short-term prices reduces the need to operate these units, thereby reducing peak NOx emissions near major load centers, assuming that emissions by distributed generation do not ramp up and erase that reduction.

3. Recommended Procedure for Revising Bid Cap

Assuming that the $250/MWh Bid Cap was appropriate when natural gas prices were $2.50/MMBTU to $3/MMBTU, it is possible to derive a procedure for adjusting the bid cap to reflect current natural gas prices using information on the heat rate of the least efficient class of natural gas-fired units in California and an estimate of the variable operating and maintenance costs of these units. Because of the thinness of the short-term natural gas market in California and the state's experience with misreporting of natural gas transactions prices during the winter and spring of 2001, we do not recommend a trigger for raising bid cap based on California natural gas prices. Instead, we base our analysis on average values of Henry Hub futures prices for the winter of 2006, which are currently in the range of $12/MWh.

The least-efficient natural gas-fired units in California have heat rates in the range of 17 MMBTU/MWh. Multiplying this heat rate by a $12/MMBTU gas price and adding a $6/MWh variable operating and maintenance cost (that has been approved by FERC in setting a number of cost-based rates) yields a variable cost estimate of $210/MWh. Multiplying this same heat rate by $3/MMBTU yields a variable cost estimate of approximately $60/MWh. Subtracting this $60/MWh

[4] California ISO Market Surveillance Committee, "Opinion on the California ISO's Market Redesign and Technology Upgrade (MRTU) Conceptual Filing," April 26, 2005. (At http://www.caiso.com/docs/2005/04/26/2005042611125729395.pdf)

variable cost estimate from \$250/MWh yields a \$190/MWh difference that could be applied to going-forward fixed costs at a natural gas price of \$3/MMBTU. Applying this same \$190/MWh value to the \$210/MWh variable cost estimate yields a bid cap of \$400/MWh. This bid cap provides the same headroom at a \$12/MMBTU natural gas price that a \$250/MWh bid cap provided at a \$3/MMBTU natural gas price. From this perspective, a \$400/MWh bid cap today could therefore be seen as consistent with the \$250/MWh bid cap in 1998.

Because natural gas prices are not likely to return to \$3/MMBTU level and may even rise beyond \$12/MMBTU during the winter of 2006, a \$400 bid cap should be sufficient to ensure that further increases in natural gas prices will not cause the variable costs to approach the bid cap and create the distortions and reliability concerns outlined above. This higher bid cap makes it even more imperative that the CPUC continue to work toward increasing the degree of participation of final consumers in the wholesale market. As noted above, this bid cap increases the potential benefits that final consumers can realize from managing short-term wholesale price risk for some or all of their consumption.

4. Concluding Comments

The levels that natural gas prices may reach during the winter of 2006 could make the variable cost of some generation units in the WECC higher than the current \$250/MWh bid cap. This opinion has suggested an approach to raising the bid cap based on expected natural gas prices during the winter of 2006 and the return to fixed costs that was implicit in the \$250/MWh bid cap at \$3/MMBTU natural gas prices.

It important to emphasize that many of the arguments against raising the bid cap during the period from June 2000 to June 2001 are no longer relevant. Virtually all of California load is covered by fixed-price forward contracts or tolling arrangements between generation unit owners and LSEs, so suppliers to the California market have significantly less incentives to raise the short-term price of electricity because they typically earn this price on only a small fraction of the output they produce. Moreover, bidding to increase the short-term price also reduces the likelihood that their units will not be dispatched to serve load, which increases the risk that these suppliers will sell less than their forward commitments in the short-term market.

If LSEs are adequately hedged with fixed-price forward contracts for energy, then there are limited costs to raising the bid cap that should be outweighed by the significant potential reliability benefits to consumers of a higher bid cap. With the right conditions in the retail market, the ultimate goal should be to raise the bid cap on the short-term market to a level that limits the reliability risks of a bid cap. Clearly, the higher the bid cap, the less likely there is to be a supply shortfall, because final consumers will reduce their demand in response to higher short-term electricity prices. All market participants will then benefit from greater grid reliability and lower capital costs because the same number of consumers can be served with less total generation capacity.

For these reasons, we support raising the bid cap to \$400/MWh before the winter of 2006, rather than wait until the price of natural gas rises above some level. We believe this is preferable to raising the bid cap in response to evidence of either reduced supply to the real-time market or bids above the \$250/MWh cap. As noted earlier, the bid cap is scheduled to increase to \$500/MWh in 2007. Some experience with a higher bid cap with current market design appears to us a lower risk strategy for transitioning to the eventual $500/MWh bid cap. We also do not support lowering the bid cap in the event that natural gas prices subsequently fall. Instead, we view this bid cap increase as an opportunity to realize the system reliability improvements and average wholesale energy cost reductions that can result from a wholesale market with active participation by a significant fraction of final demand. We hope that CPUC will support this by implementing tariffs for all customers with hourly meters that allow them to benefit from more active demand-side participation in the wholesale market.

ATTACHMENT E

Memorandum

To: Operations Committee

From: Keith Casey, Director, Market Monitoring

cc: ISO Officers, ISO Board of Governors

Date: December 9, 2005

Re: Market Monitoring Report

This is a status report only. No Board Action is required.

As part of the CAISO's realignment process, market performance reporting to the Board of Governors has been transferred to the Department of Market Services. Going forward, the Market Monitoring Reports to the Board of Governors will focus on analysis of issues that may be impacting market performance or system reliability. The following provides a summary of the current issues being analyzed by the Department of Market Monitoring.

Raising the Damage Control Bid Cap from $250/MWh to $400/MWh.

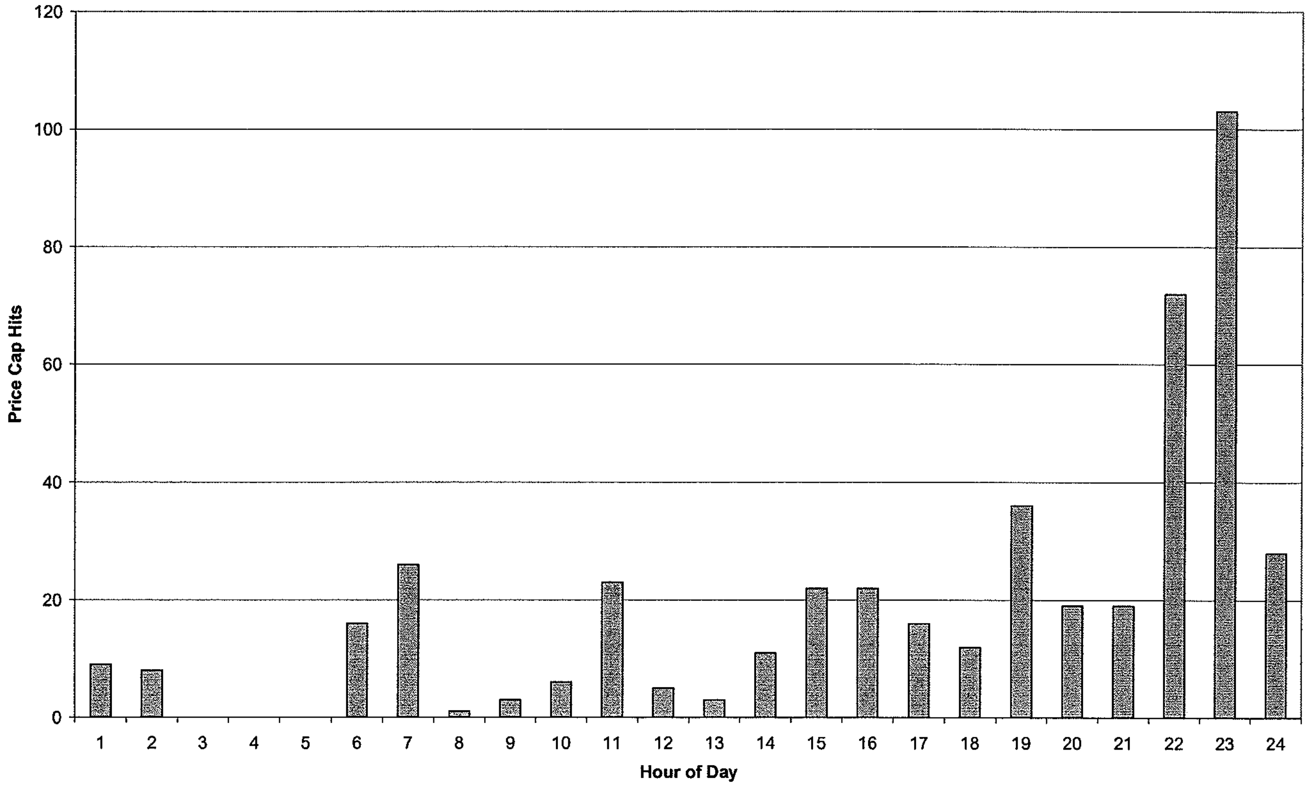
On November 9, 2005, in response to a request from the Department of Market Monitoring, the ISO Market Surveillance Committee (MSC) provided an Opinion on raising the level of the Damage Control Bid Cap (DCBC) on the real-time energy market. The current cap is a $250/MWh "soft bid-cap", which means that accepted market bids above $250/MWh are ineligible to set the market clearing price, are paid as-bid, and subject to cost-justification with FERC. The MSC recommends raising the bid cap to $400/MWh based primarily on a concern that generation unit-level variable costs could approach or exceed the current cap level of $250/MWh due to high and volatile natural gas prices. The MSC also noted that a $400/MWh bid cap would be more comparable to a $250 bid cap given the significant increase in natural gas prices since the $250/MWh bid cap was originally established. Additionally, they argued a higher bid cap would further encourage the development of demand response programs.

The Department of Market Monitoring supports the MSC's recommendation. Market conditions have changed significantly since the 2000-2001 energy crisis. The California IOUs have largely hedged their exposure to spot market energy prices for summer 2006 through long-term forward energy contracts that are set at a fixed price or a price indexed to natural gas prices. This leaves the majority of the load in the ISO control area with very small cost exposure to spot market energy prices and shifts the spot market price risk to the supply side of the market, which provides suppliers with incentives to keep spot market prices low.

The high level of forward energy contracting in California has resulted in very low volumes of energy transacted in the real-time energy market. Over the past year, average underscheduling was only 2.1 percent of the total wholesale energy requirements. Although the real time market does experience occasional prices spikes and market volumes above 5 percent of total wholesale energy requirements, primarily during periods of fast load ramps or unexpected high loads, the bid cap is seldom binding in these periods as there is generally a sufficient amount of bids provided under the cap. Raising the price cap would primarily impact those periods when the bid cap constrains the market clearing price. DMM analysis shows that 5-minute prices were at or just under the $250 cap in only 460 five-minute intervals since January 2005, which equates to approximately 0.5% of the total 5-minute intervals during that period. High real-time energy prices usually occur during periods of fast load or generation ramping (HE7, HE19, and HE 22-23), which can occur in any season, and high summer load periods (HE 14 through HE 18). The following chart shows the distribution of cap constrained price hours since January 2005.

Figure 1. Number of SP26 Interval Prices at or near the $250 Cap by Operating Hour[1]

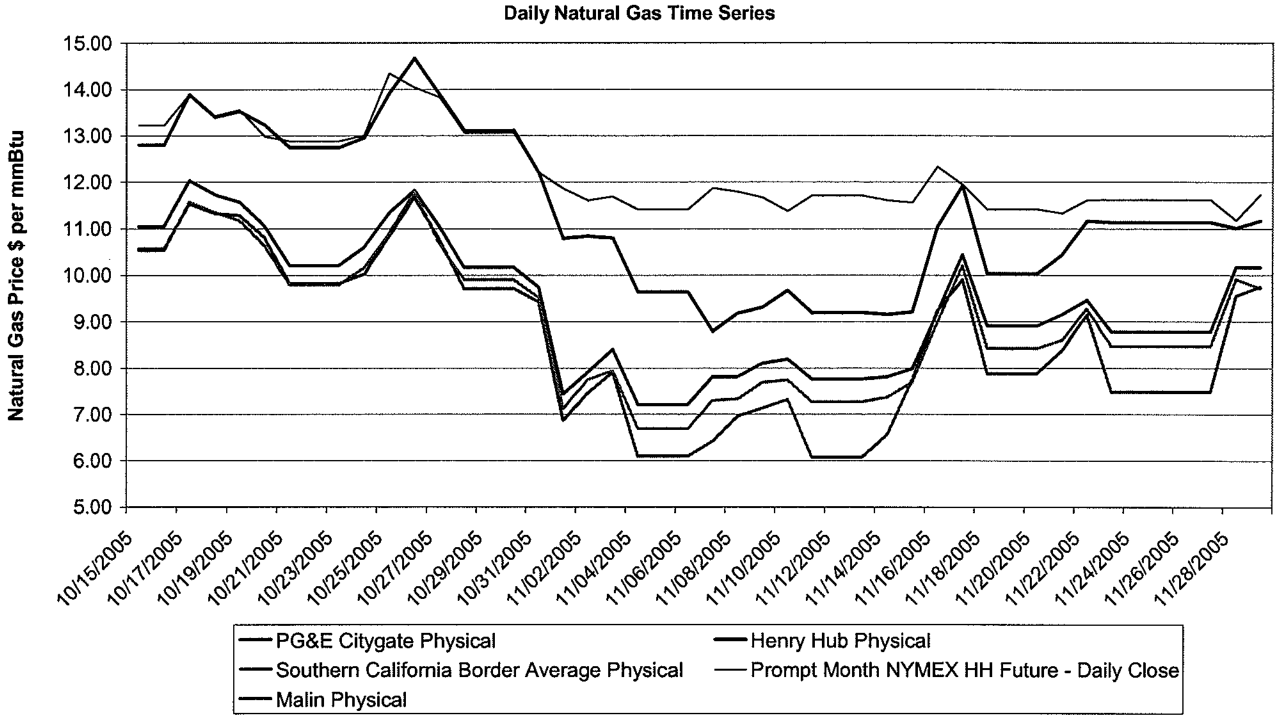
January - November 2005



The current $250/MWh bid cap on the California ISO's real-time energy market was most recently established in October 2002 when natural gas prices were between $3 and $4/mmbtu. In recent months, concerns over tight natural gas supply have resulted in very high and volatile natural gas prices throughout the country. Natural gas spot prices in California recently reached as high as $12/mmbtu and have been extremely volatile. Though natural gas prices have moderated in recent weeks, they could easily rebound higher during the critical winter heating demand months (December-March). The following chart shows the recent trend in natural gas physical and prompt month NYMEX futures prices since May 2005.

[1] This analysis uses a definition of a price cap hit as a price within $1 of the $250 price cap; i.e. at least $249/MWh. The period of analysis was January 1 through November 14, 2005.

Figure 2. Daily Natural Gas Physical and Futures Prices



Given these significant changes in market conditions, DMM recommends that the real-time energy market Damage Control Bid Cap be increased from $250/MWh to $400/MWh. Raising the bid cap under current market conditions would provide several significant benefits to the California energy markets.

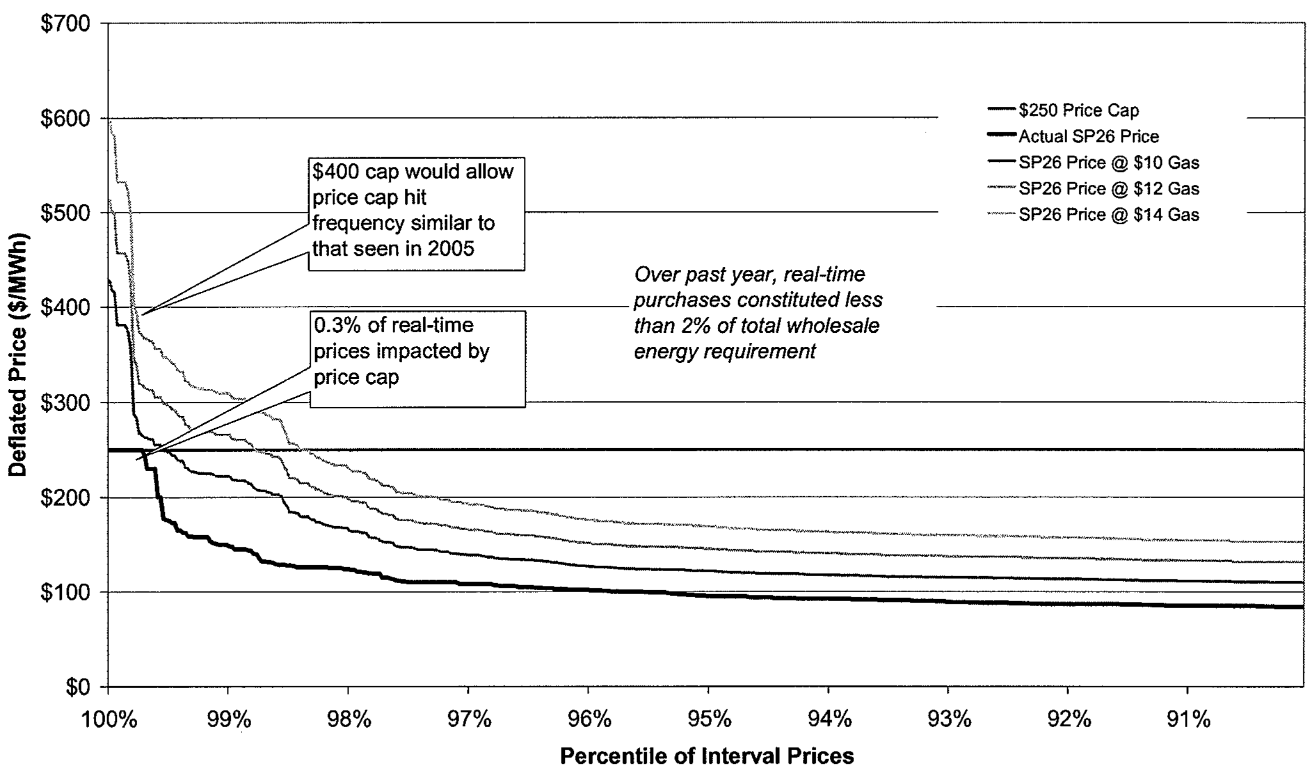
- A higher bid cap would provide several reliability benefits critical to maintaining reliable grid operation given the tight supply margins forecast for next summer.
  1. It would provide greater incentives for generator owners to maintain their units at a high level of availability so they mitigate the risk of experiencing a forced outage during a critical peak load hours.
  2. It would provide greater incentives for further development of demand response programs such as real-time pricing. Such demand programs would reduce reliance on high cost, environmentally unfriendly combustion turbines during critical peak demand hours and increase supply margins during peak load periods.
  3. It would promote reliability by providing greater fixed cost recovery for generating units during high demand periods when supply margins are tight and prices are at or near the bid cap. Several generating units in California are at risk of retirement due to insufficient fixed cost recovery. Moreover, some new generating units in the CAISO Control Area do not have long-term power contracts and a higher spot price during critical peak periods will help to make these units more economically viable.
  4. Should gas prices escalate significantly over the winter months in response to high gas heating demand or supply disruptions, a higher cap would not discourage suppliers, particularly importers, from selling into the California real-time energy market since they would be assured bid cost recovery for accepted bids above

$250/MWh. A higher cap would also provide a greater incentive to internal suppliers with options of selling their output to external load through the western bilateral short-term energy markets to instead provide real-time energy bids to the CAISO.

- A higher bid cap would provide greater incentives for the LSEs to continue to minimize their spot market exposure by signing additional long-term power contracts.
- Finally, increasing the cap to $400/MWh would provide a measured transition to the $500/MWh energy bid cap scheduled to be invoked with the California ISO's new market design in February 2007.

As discussed above, over the past year the current $250/MWh bid cap has been binding in only a small number of periods. However these periods are often the most critical times that real-time energy is needed to maintain system reliability. The following chart compares the actual price duration curve (prices stacked from highest to lowest) from May 2005 through September 2005 to price duration curves adjusted for higher gas prices.[2] As shown in the chart, the current bid cap impacted approximately 0.3 percent of interval prices during the past summer, and a higher cap would allow prices to reflect higher natural gas price levels. If gas prices over the next year are in the $10/MMBTu range and the ISO experiences similar market conditions to this year, this analysis suggests real time prices would only exceed $250/MWh in fewer than 0.5 percent of 5-minute pricing intervals seen in the summer of 2005, and high prices during these periods would be impacting a relatively small amount of demand.

Figure 3. SP26 Real-time Energy Market Clearing Price Duration Curves at Different Natural Gas Price Levels, May through September 2005



[2] Each interval price was deflated to using the formula: (price - $4 O&M) * (comparison gas price / actual daily gas price) + $4 O&M. Comparison gas prices used were $10, $12, and $14/MMBtu.

Given the current market conditions discussed above, the DMM concludes that the reliability risks associated with not raising the cap far outweigh any risk of increased prices from a higher bid cap. As noted above, the spot market risk for load serving entities is minimal. Moreover, a higher bid cap is unlikely to have an appreciable effect in increasing the costs of bilateral energy contracts because load serving entities have indicated they have already contracted for the vast majority of their energy requirements for next summer and any additional new contracts would likely extend beyond 2006 and therefore would in any case be reflective of the $500/MWh bid cap ordered by FERC to take effect upon implementation of MRTU in February 2007. Finally, any local market power concerns stemming from a higher bid cap and the potential of having must offer obligations revoked by FERC this summer, will be addressed by the current local market power mitigation measures. Should the exercise of local market power become more prevalent in 2006, for whatever reason, the adequacy of local market power mitigation measures will be assessed and to the extent the current mitigation is found to be inadequate, new mitigation measures will be proposed. In other words, maintaining a lower bid energy cap (i.e., $250) would not be an adequate backstop for potentially inadequate local market power mitigation rules. If the current local market power mitigation rules were determined to be inadequate, DMM would seek to have them modified.

For these reasons, DMM agrees with the MSC and recommends that the real-time energy market bid cap be increased from a $250/MWh soft cap to a $400/MWh soft cap. In addition, DMM recommends the bid cap for adjustment bids used in the Day Ahead and Hour Ahead Congestion Management Markets also be increased to $400/MWh and that the bid cap for the Ancillary Service Markets remains at $250/MW.

Utilization of Contingency Reserves under MRTU

The following summarizes the key findings and recommendations of the Department of Market Monitoring's investigation into the reasons that ISO grid operators did not dispatch contingency reserves on the afternoon of August 25, 2005, a warm day with temperatures 14 degrees above forecast, during which the Pacific DC Intertie failed, resulting in 1,800 MW of shed load. During this event, the SP26 real-time market-clearing price was set at $120.92/MWh and certain resources flagged as contingency reserve were dispatched out-of-sequence with bids as high as $249.99/MWh. As previously reported last month, these contingency reserve bids should have been dispatched in-sequence and allowed to set the market clearing price. DMM reported this issue to Market Operations and they are in the process of correcting real-time market prices for that event. DMM further reviewed this issue to understand why it occurred and what could be done in the future to avoid a reoccurrence.

In discussing this issue with Market Operations, operators identified two issues with managing the use of contingency reserve bids:

1. Confusion due to multiple commodity price sheets for the same operating hour, and
2. Processing delays and manual entries associated with dispatching Contingency Reserve within RTMA

These two issues are discussed below:

1. Confusion due to multiple commodity price sheets for the same operating hour.

   Problem: Prior to real time, operators print out commodity sheets from the software. These printed commodity sheets are hard copies of the lists of bids comprising the real-time market and are used for reference to allow operators to know which resources are dispatchable in the event that there is a computer malfunction in real time. Operators have three different commodity sheets for the operating hour:

- A sheet of *original bids.* This list consists of suppliers' actual bids submitted into the market. This sheet excludes proxy bids (i.e., filled-in bids, pursuant to the Must-Offer Obligation, from suppliers that did not actually submit bids)
- A sheet of *constrained supplemental bids.* This sheet includes bids for all dispatchable supplemental resources (including proxy bids) but excludes energy bids from procured contingency operating reserves.
- A sheet of *unconstrained supplemental bids.* This sheet includes bids for all supplemental resources, including proxy bids and bids from contingency operating reserve.

Operators indicated having multiple commodity sheets was confusing and creates the potential for operators to inadvertently dispatch resources from the wrong sheet.

Solution: Operators would prefer a single commodity stack with all resource information. This would enable them to know the available resources without inadvertently missing certain classes of resources.

2. Contingency Dispatch Usability and Delay

Problem: During a zonal contingency, as was the case during the August 25th event, operators must take several steps to dispatch contingency reserves within a constrained zone. In such a case, he or she must: 1) Switch from the commodity dispatch screen to the contingency flagging screen; 2) Manually un-select the individually resources outside the constrained zone so that the only contingency reserves released to the market are those in the constrained zone; and 3) Switch back to the commodity screen to dispatch.

When RTMA is working optimally, this entire sequence takes a few minutes. However, during a volatile situation such as a contingency, many users are impacting the computer server network and operators may experience significant system delays. This entire procedure can take many minutes, and at times operators' terminals may lock up completely.

Solution: A single button on the commodity dispatch screen should be able to dispatch all resources (including contingency only reserve bids) in a single congestion zone. Additionally, poor server system performance and delays of this magnitude should be considered unacceptable by the ISO and fixed. This a critical time that RTMA needs to have high performance for the dispatching of dozens of units during a major event where time is critical. Switching between screens to set every flag to the right setting is time consuming. One button on the dispatch screen should be able to perform this function.

During the August 25th event, because a grid operator was concerned about the time it would take to dispatch contingency reserve utilizing the RTMA software contingency clearing function, they opted to dispatch manually using the commodity sheet. However, they inadvertently used the "constrained" sheet, which does not show contingency non-spinning reserve bids. These units were dispatched out-of-sequence only after the scheduling coordinator contacted the operator on the telephone to inform him that they were available. This type of situation could be avoided in the future if the solutions proposed above are adopted.

Intrazonal Congestion South of Pastoria

Recently, as loads have subsided in the central valley of California, significant intrazonal congestion has frequently occurred on the transmission system south of the Pastoria substation. During the period of September 1st through November 17th, redispatch costs totaled approximately $5.23 million as a result of decremental dispatches to the

Pastoria (70 percent) and Big Creek (30 percent) generation stations to mitigate the congestion. DMM has been monitoring the situation closely given the lack of competition to relieve the congestion in the area. Under the current local market power mitigation rules, units dispatched out-of-sequence in the decremental direction are charged their decremental reference level, which is determined independently by Potomac Economics. Reference levels are generally established as the average price of accepted bids for the previous ninety days, unless there are no bids or the unit owner has requested a cost-based determination. In response to competitive problems with the Mexican border generation units and Miguel congestion beginning in the summer of 2003, the ISO worked with Potomac to institute a competitiveness screen for out-of-sequence decremental dispatch instructions. Under the screen, a generating unit must have at least 50 percent of their decremental bid volumes dispatched in-sequence over the previous ninety days to have their reference levels set by the bid-based methods. If less than 50 percent of their bids were dispatched in-sequence, Potomac will set their reference levels using the cost-based method.

Since congestion became prevalent south of Pastoria in mid-September, a significant amount of Pastoria's decremental dispatches have been out-of-sequence. DMM is consulting with Potomac to determine whether it is appropriate to implement cost-based reference levels for Pastoria. DMM is also working with the ISO's market and grip operations staff to verify that congestion mitigation in the area is being properly implemented under the ISO's operating procedure (M-401).

RTMA (Real-time Market Applications) Software Issues

$250/MWh Damage Control Bid Cap Enforcement

In recent months, DMM uncovered the fact that RTMA damage control bid cap has not been enforced properly. Under the ISO Tariff, the current damage control bid cap allows a range from -$30/MWh to $250/MWh where the clearing price (MCP) for each 5-minute dispatch interval may be set. DMM has observed that while resources with bid prices equal to $250/MWh were being dispatched by RTMA, the MCP was set at the next lowest marginal bid dispatched. Since RTMA was implemented in October 2004, there has not been a single instance of the MCP set to $250/MWh. DMM raised this issue with Market Operations who performed an investigation. Market Operations determined that the root cause of the issue is the design inconsistency in RTMA software in handling a small internal adjustment of the price curve data of resource economic bids submitted by scheduling coordinators (SC). In effect, bids that were submitted at the bid cap of $250/MWh were adjusted to $250.001/MWh by the software and no longer eligible to set the market clearing price. Market Operations has identified 437 intervals (approximately 36 hours) where the price should have been set at $250/MWh but was instead set at the next lowest priced marginal bid dispatched by RTMA. DMM estimates that the market impact of this issue to be between $2 and $3 million. The RTMA software will be corrected so that bids submitted at the price cap are eligible to set the market clearing price as specified by the ISO Tariff. Settlement reruns will also take place to account for the correct prices.

$12/MWh Price Issue

As DMM reported last month in its RTMA Assessment, Market Operations identified instances of erroneous $12/MWh prices being set by RTMA. After an investigation, they determined that $12/MWh prices were being set by RTMA during instances in which all units dispatched were dispatched at their maximum ramping levels. The rules built into the RTMA software will not allow a unit that is ramped at its maximum ramp rate to set the market clearing price. In these instances the price is set to $12/MWh. Market Operations has sent a proposed solution to this problem to ABB, the ISO's RTMA software vendor. The ISO has concluded that a software fix for this issue is too costly and the ISO will continue to reset these prices to the previous interval price in the ISO's 96-hour correction process. Since this issue was uncovered, DMM has observed only 40 instances of erroneous $12/MWh prices set by RTMA since it was implemented in October 2004.

$0/MWh Price Issue

On July 31, 2005, Market Operations observed that the real-time market clearing price as determined by RTMA software were at $0 for many of the 5-minute dispatch intervals between operating hours 2 through 10. Further investigation by CAISO Market Operations on RTMA save cases found that for those intervals with $0 pricing as determined by ex-ante and ex-post pricing dispatches, the MCP determined by RTMA physical run were non-zero values, between $5 and $40.

Unable to explain these prices produced by RTMA, CAISO asked the RTMA vendor (ABB) to provide an explanation for the $0 pricing phenomenon. They subsequently reported to CAISO that they found a software defect in the RTMA ex-ante (and ex-post) pricing dispatch component. This defect could cause, but not always, the lowering or the increasing of the value of MCP for settlement from the correct value. Moreover, the incorrect MCP is not necessary a $0 value. This problem was corrected in the RTMA software in late October.

RCST Settlement

DMM has been involved in reviewing the Reliability Capacity Services Tariff (RCST) proposal offered by the Independent Energy Producers in their filed complaint to FERC concerning the current Must Offer requirements and generator revenue adequacy. Since the ongoing settlement discussions on this issue are subject to confidential treatment under FERC Rule 602, DMM has provided its recommendation on this issue in a separate confidential memorandum to the Board for the Board's Executive Session meeting on December 9th.

ATTACHMENT F

Board of Governors 12/16/2005 **Damage Control Bid Cap Raise**

Moved, That the ISO Board of Governors authorizes Management to file an Amendment to the ISO tariff with the Federal Energy Regulatory Commission to raise the current $250/MWh Damage Control Bid Cap for Real-time Energy Bids to a $400/MWh hard cap. ISO Management is also authorized to include in the Amendment an increase in the congestion management adjustment bid cap to $400/MWh. ISO Management will revisit the level of the bid cap whenever circumstances arise that are detrimental to market performance or reliable system operation.

Moved: Lowe Second: Cazalet

Board Action: **Passed** Vote Count: **5-0-0**	
Cazalet	Y
Gage	Y
Lowe	Y
Willrich	Y
Wiseman	Y

Motion Number: <number>

ATTACHMENT G

CALIFORNIA ISO

CAISO to File Amendment No. 73 Today to Implement New $400 Hard Bid Cap

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Summary: The CAISO is filing Amendment No. 73 to the CAISO Tariff to implement a $400 hard bid cap for real-time Energy bids and Congestion Management Adjustment Bids effective as of January 1, 2006, or as soon thereafter as possible. The CAISO will be seeking expedited consideration of Amendment No. 73 by FERC and will be requesting a December 28, 2005 comment date.

On December 16, 2005, the California Board of Governors authorized the CAISO to file a tariff amendment raising the existing $250/MWh bid cap on real-time Energy bids and Adjustment Bids used in the CAISO's Congestion Management markets to a $400/MWh bid cap. In addition the Board of Governors directed that the new $ 400/MWh bid cap be a "hard cap" rather than a "soft" cap, as exists now. Today, December 21, 2005, the CAISO will be filing Amendment No. 73 to the CAISO Tariff to implement a $400/MWh hard bid cap for real-time Energy bids and Adjustment Bids. The bid cap on Ancillary Services capacity will remain $250. The CAISO will be seeking expedited consideration by FERC to allow Amendment No. 73 to become effective on January 1, 2006 or as soon thereafter as possible and will be requesting a December 28, 2005 comment date. A copy of Amendment No. 73 will be posted on the CAISO web site.

For More Information Contact: Sidney Davies at sdavies@caiso.com 916.608.7007

California ISO Communications

CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>

The California ISO strives to be the preferred provider of superior electrical transmission services for the benefit of our customers in California and the West.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all the entities that the document states are to receive service, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California on this 21st day of December, 2005.

Anthony Ivancovich / BRM

Anthony Iva~~nc~~ovich