Date Stamp & Return

California ISO
Your Link to Power

California Independent
System Operator Corporation

FILED
SECRETARY OF THE
COMMISSION

2008 JUN 17 P 4: 35

FEDERAL ENERGY
REGULATORY COMMISSION

June 17, 2008

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Amendments to MRTU Tariff Provisions, Docket No. ER08-___-000.

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Federal Energy Regulatory Commission's regulations, 18 C.F.R. § 35 *et seq.*, the California Independent System Operator Corporation ("CAISO") submits an original and five (5) copies of proposed tariff revisions.

Respectfully submitted,

Anna McKenna

Anna McKenna

Counsel for the
The California Independent System Operator
Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7296

California Independent
System Operator Corporation

June 17, 2008

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Amendments to MRTU Tariff Provisions, Docket No. ER08-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35 *et seq*., the California Independent System Operator Corporation ("CAISO") submits an original and five (5) copies of proposed revisions to the current ISO Tariff and the Market Redesign and Technology Upgrade ("MRTU") Tariff. The MRTU program is a comprehensive redesign of the California electricity markets and is aimed at enhancing reliability and increasing the efficient utilization of the CAISO Controlled Grid.

As part of this effort and pursuant to the order issued by the Commission on September 21, 2006,[1] the CAISO has identified certain improvements that will further enhance the CAISO's congestion management solutions by appropriately pricing and modeling interchange transactions, *i.e.*, imports and exports between the CAISO Controlled Grid. The proposal will establish an interconnected Balancing Authority Area ("BAA") which the CAISO proposes to apply upon MRTU start-up to interchange transactions with the Sacramento Municipal Utility District ("SMUD") BAA and the Turlock Irrigation District ("TID") BAA. The proposal prevents the unjust and unreasonable scheduling and pricing of such interchange transactions, improves reliability, and prevents CAISO ratepayers from having to pay inappropriate prices and unnecessary uplift charges associated with inaccurate modeling and pricing of such transactions.

Specifically, the CAISO respectfully requests Commission approval of tariff amendments that: (1) establish the SMUD BAA[2] and the TID BAA as an Integrated Balancing Authority Area

---

[1] *California Independent System Operator Corporation*, 116 FERC ¶ 61,274 (2006) ("September 2006 Order").

[2] In addition to SMUD's own transmission system, the SMUD BAA includes the transmission facilities of: (a) the Western Area Power Administration – Sierra Nevada Region ("Western"); (b) the Modesto Irrigation District

("SMUD-TID IBAA" or "IBAA") to be implemented in conjunction with MRTU start-up and therefore incorporated into pre-production testing prior to start-up; (2) authorize the CAISO to implement a single-hub IBAA default modeling and pricing approach for interchange transactions with the SMUD-TID IBAA (including the opportunity for the CAISO provide alternative, non-default modeling and pricing arrangements based on entities providing the CAISO with certain information), similar to the practices adopted by the Eastern Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs"); (3) provide a process for the adoption of a new IBAA or changes to an existing IBAA; (4) provide a process for coordinating the adoption of a new IBAA or changes to an existing IBAA with the release of Congestion Revenue Rights ("CRRs"); and (5) provide a process for parties to adjust the definition of previously-released CRRs that are not consistent with the new IBAA modeling and pricing approach to be in effect during the effective term of such CRRs.

With the exception of the CRR-related tariff provisions, the CAISO requests an effective date for the IBAA proposal upon implementation of MRTU. The CAISO respectfully requests an effective date for the CRR-related provisions of *sixty days from the date of filing* so that CRR Holders of previously-released CRRs may have an opportunity to elect to reconfigure their previously-released CRRs prior to the start of the next annual CRR release process to be conducted later this summer.

The CAISO also respectfully requests that the Commission issue an order approving all of the changes described herein within *sixty days from the date of filing*. As discussed in greater detail in Section IV, *infra*, a 60-day order approving the IBAA is necessary in order to allow the proposed and Commission-approved functionality to be incorporated into the MRTU market systems and fully tested in time for the start of MRTU in the fall of 2008.

I. INTRODUCTION & EXECUTIVE SUMMARY

The objectives of the IBAA proposal are three fold. The most important objective is to protect CAISO ratepayers from unjust and unreasonable prices that may result in the absence of the CAISO having accurate information that allows the CAISO to verify the location of external resources within the SMUD and TID BAAs that are dispatched to implement interchange transactions between those BAAs and the CAISO. The second objective is to appropriately model and price interchange transactions, *i.e.*, imports and exports, between the CAISO Controlled Grid and the highly-integrated SMUD and TID BAAs in a manner consistent with the use of locational marginal prices ("LMPs") under MRTU. A third objective is to establish a process whereby the CAISO can enhance the accuracy of the CAISO's congestion management process by including the transmission facilities of other interconnected BAAs (as well as the external resources supporting scheduled interchange transactions with those BAAs) in the Full Network Model. In addition, the IBAA proposal also includes provisions to ensure consistency

("MID"); (c) the City of Redding ("Redding"); and (d) the City of Roseville ("Roseville"). The TID BAA contains TID's transmission facilities.

between the settlement of Congestion Revenue Rights ("CRRs") and the settlement of interchange transactions between the CAISO and an IBAA.

The CAISO respectfully requests that the Commission approve tariff amendments that capture the objectives stated above. In particular, the CAISO requests that the Commission approve the establishment of the SMUD-TID IBAA in conjunction with MRTU start-up and therefore its incorporation into pre-production testing prior to start-up.

A. The Need For the IBAA Proposal

Implementation of the IBAA proposal at the start of MRTU is extremely important because it: (a) prevents the potential for the "infeasible schedule" problem to occur with interchange transactions with the SMUD-TID IBAA, a significant problem which the Commission has previously recognized and which MRTU set out to solve as a whole, and (b) ensures that CAISO ratepayers will not be subject to the adverse implications of inappropriate pricing for interchange transactions with the SMUD-TID IBAA due to the CAISO's inability to accurately reflect and model the actual resources that are supporting such transactions. Specifically, the IBAA proposal will protect CAISO ratepayers from having to pay inappropriate prices and unnecessary uplift costs by:

(a) addressing the "infeasible schedule" problem and making the operation of the CAISO Controlled Grid more reliable by establishing feasible forward-market schedules and appropriately pricing interchange transactions with the IBAA and thereby avoid the need for constant real-time re-dispatch to correct infeasible forward-market schedules;

(b) avoiding the creation of unjust and unreasonable scheduling incentives and pricing of interchange transactions where the prices are not representative of the value of power injected at such locations for purposes of managing congestion on the CAISO Controlled Grid; and

(c) having a more reasonable and more accurate assessment of the impacts of interchange transactions on the CAISO Controlled Grid, thereby increasing the effectiveness of the congestion management process on the CAISO Controlled Grid.

Considering the 2000-2001 energy crisis in California, its aftermath, and the Commission's directives for the CAISO to "fix" its congestion management system (as well as the tremendous collective effort of the CAISO, market participants and the Commission to implement MRTU), it would be wholly unreasonable for the CAISO and the Commission not to apply fundamental MRTU market design principles to interchange transactions between the CAISO and the SMUD-TID BAA. Such a result would undermine a primary goal of MRTU by allowing infeasible interchange schedules to be established adversely affecting the reliable operation of the transmission system and causing consumers to pay inappropriate costs resulting from inaccurate LMPs and inaccurate real time re-dispatch costs due to a disparity between the scheduled location of the external resources and the actual location of the external resources dispatched within the IBAA. Such a disparity is the result of the unwillingness of the entities within the IBAA to provide the CAISO with information regarding interchange transactions.

The IBAA proposal protects against these undesirable consequences. Moreover, the "proxy bus" mechanism which is the centerpiece of the IBAA proposal is a proven mechanism successfully used by the RTOs and ISOs in the east to address the modeling and pricing of interchange transactions with an LMP regime in use in the modeling region.[3] The mechanism was developed specifically to prevent the type of inappropriate market incentives and modeling inaccuracies that the CAISO is seeking to avoid with its proposal. Consistent with the experience of the eastern RTOs/ISOs, and the knowledge gained by that experience in addressing the problems associated with interchange transactions, the Commission should approve the CAISO's IBAA proposal as a just, reasonable and proven method of addressing such problems.

B. The IBAA Proposal

The CAISO proposes to establish a single IBAA comprised of the SMUD BAA and the TID BAA for the purpose of appropriately pricing and modeling interchange transactions between the CAISO Controlled Grid and the IBAA. While the SMUD and TID BAAs are no longer part of the CAISO BAA, the transmission systems previously were part of the CAISO BAA and were built or configured in a highly-integrated manner with the facilities that comprise the CAISO Controlled Grid. The SMUD BAA and the TID BAA cover a large area in the center of northern California and their combined transmission system facilities runs in parallel with major parts of the CAISO Controlled Grid.[4]

The SMUD and TID BAAs also are the most integrated with the CAISO Controlled Grid based on the quantified parallel flows observed between the systems, which is not surprising given that these now separate BAAs were developed as part of a single control area and grew in an integrated manner. The SMUD BAA alone has ten (10) interconnections with the CAISO Controlled Grid, far more than any other BAA with which the CAISO is interconnected (the next highest number of interconnections is four). The TID BAA has two interconnections with the CAISO and is directly connected with the SMUD BAA. Instead of modeling and pricing interchange transactions as if the associated energy injections or withdrawals were located at one of the 12 interconnection points, the proposed IBAA (*i.e.*, the combination of the SMUD BAA and the TID BAA) is configured as a single-hub with default "proxy buses," *i.e.*, default modeling and pricing points for interchange transactions. The SMUD-TID IBAA will have a separate default pricing point for imports to the CAISO Controlled Grid and a separate default pricing point for exports from the CAISO Controlled Grid.

As explained in more detail in Section IV.A.1, *infra*, under the default approach all imports to the CAISO Controlled Grid from the IBAA will be modeled and priced based on the

---

3 The term "proxy bus" is used with the eastern RTOs and, unless otherwise noted, the term has the same meaning as the term "pricing point" used in this transmittal letter.

4 Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price at 33-35.

injections and LMPs calculated at the Captain Jack Substation in Oregon. All exports from the CAISO Controlled Grid to the IBAA will be modeled and priced based on the injections and LMPs calculated at the SMUD-Hub.[5] Significantly, the IBAA proposal permits use of alternative (or non-default) modeling and pricing arrangements if a market participant agrees to provide the CAISO with more precise information regarding the location and operation of the resource(s) used to implement interchange transactions between the IBAA and the CAISO. The information must allow the CAISO to verify whether the resources, in fact, were dispatched in real time to implement the interchange transaction.[6]

C. The Process Leading Up to the IBAA Proposal

The IBAA proposal outline herein is the culmination of a lengthy process that began at the start of the CAISO's decision to move to LMP pricing and the related desire to have a Full Network Model that includes a network representation of the entire Western Electricity Coordinating Council ("WECC") transmission network.[7] The CAISO's desire for a more detailed exchange of data between Balancing Authorities has been consistently voiced across a number of related efforts, including: (i) the MRTU filing and the intent to include embedded and adjacent control areas (now IBAAs) in the full Network Model; (ii) the attempt to resolve certain "Seams Issues" in the west per the Commission's orders;[8] (iii) the attempt to enter into data sharing arrangements necessary to support the newly adopted mandatory NERC reliability standards;[9] and (iv) a collaborative effort between the CAISO and other members of the now defunct Seams Steering Group – Western Interconnection ("SSG-WI") which formulated and published a conceptual proposal for coordinated day-ahead scheduling and congestion management across the entire western region.

The elements of the CAISO's single hub, default pricing point proposal result directly from the limited type and amount of information the CAISO expects to receive from IBAA Entities[10] regarding interchange transactions at the start of MRTU. It is clear from a review of the process on Seams issues and the IBAA stakeholder process, as provide in Attachment E to

---

5 The SMUD-Hub is described, *infra*, in Section IV.A.1 n. 52 of this Transmittal Letter.

6 *See* Exhibit ISO-2, Testimony of Dr. Hildebrandt at 12, 16-18. The alternative arrangement could be with the SMUD BA, the TID BA, or other market participants (*e.g.*, resource owners or operators) that can provide the requisite information to the CAISO.

7 The process began on (and the CAISO's intent was expressed as far back as) May 1, 2002 when the CAISO filed its Comprehensive Market Redesign Proposal ("MD02"). *See* Attachment E to this filing "Summary of IBAA Development, Consultation and Stakeholder Process" at 1-2.

8 These efforts included the Commission's December 14-15, 2006 Seams Technical Conference and the filing of quarterly Seams Reports with the Commission. *See* Attachment E to this filing at 5-24.

9 *See* Attachment E at 9.

10 IBAA Entities is a collective reference to the SMUD BA, the TID BA, Western and the Transmission Agency of Northern California ("TANC"). TANC, in turn, is a joint powers agency authorized by Section 6502 of the California Government Code and is composed of the California cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, and Ukiah; the Plumas-Sierra Rural Electric Cooperative; SMUD; MID, and TID.

this Transmittal Letter, that the CAISO favors the more transparent, granular, and data intensive modeling approach. To that end the CAISO has consistently stipulated its desire and need for verifiable data regarding the location and dispatch of external resources actually used to implement interchange transactions in order to more accurately model the effect of such transactions on the CAISO Controlled Grid. The CAISO does not have this information; only the BAAs or the parties engaging in interchange transaction from the IBAA have such information. The CAISO has openly and freely admitted numerous times that it believes it is less than optimal to "estimate" the location of the external resources used to implement interchange transactions. However, the unwillingness of the IBAA Entities to exchange more useful data has been singularly instrumental in the CAISO's decision to propose a default modeling and pricing approach (which operates in the absence of data allowing the CAISO to verify the location and dispatch of the external resources used to implement interchange transactions).

The IBAA entities' unwillingness to engage in more detailed and meaningful data exchange is evident in the account of events provided in Attachment E to this Transmittal Letter. This theme is reinforced by the following excerpt from a November 14, 2007 letter from SMUD to the CAISO:

> We believe the scope of the proposed CAISO MRTU regime should only apply at the boundaries or the physical interconnection points of all ICAs [Interconnected Control Areas]. This approach is consistent with our understanding of the standard business practices of other neighboring balancing authorities/control area operators within the Western Electricity Coordinating Council (WECC).
>
> * * * *
>
> We believe as public entities, and based upon many years of experience in operating our respective systems, adequate regulatory safeguards are already in place between the CAISO and SMUD/Western and TID ICAs to allow our business activities to be transacted exclusively at our physical points of interconnection, similar to what already occurs between the ICAs within the WECC. *That negates the need for the CAISO to acquire additional data for modeling our internal operations*.[11]

In the six months of IBAA stakeholder process (and in the Commission process regarding Seams issues) conducted by the CAISO from November 14, 2007 (the date of the above-quoted letter) to May 8, 2008 , the CAISO amended its proposal and scaled back the information it

[11] November 14, 2007 Letter from James R. Shetler, Sacramento Municipal Utility District to Charles King Vice-President of Market Development and Program Development at the CAISO at 1, 2 respectively (emphasis added). After proposing a multiple hub approach in December 2007, the CAISO moved to a single hub approach with default pricing locations (in April 2008) in large part because of the reluctance of the IBAA entities to provide data to the CAISO. At the subsequent CAISO Board Meeting on May 21, 2008, the need for the default provisions were illustrated when a representative of SMUD stated that SMUD would "never" provide day-ahead data to the CAISO.

would request in response to the IBAA Entities concerns.[12] Despite the fact that the CAISO worked diligently in collaboration with stakeholders, the Market Surveillance Committee ("MSC"), Department of Market Monitoring ("DMM") and its experts to find a solution to the identified issues that does not require the data intensive effort it originally pursued, in their May 8, 2008 proposal the IBAA Entities still propose that the CAISO model interchange schedules at the boundary points/Intertie Scheduling Points between the CAISO and the IBAA.[13] Moreover, while the IBAA Entities suggested some movement could be made towards data exchanges, the terms of what data would be exchanged, how, and for what purposes were not clear and not consistently articulated by all the parties involved.

The refusal to engage in more detailed and beneficial data exchanges while insisting on a pricing structure that benefits the IBAA Entities, but imposes unjust and unreasonable costs on CAISO's ratepayers, places the CAISO in a difficult position. The combined position of the IBAA entities on the exchange of data and pricing is neither reasonable nor tenable.

It literally is impossible for the CAISO to ignore the testimony of Dr. Harvey and Dr. Hildebrand and the MSC, all of whom explain that granting the desire of the IBAA entities to have their transactions modeled and priced as if the injection is physically at the Intertie Scheduling Point is tantamount to requiring that the CAISO ratepayers pay a price for power calculated based on the "most favorable" assumptions to the IBAA entities regarding the location of the generation supporting imports from their Balancing Authority Area in *all* circumstances, regardless of whether or not the imports are actually supported by generation whose location warrants the higher price.[14] The IBAA entities should not be permitted to fail to provide the CAISO with the information it needs to accurately price and model interchange transactions and then reap the benefits of that non-transparency by receiving LMPs that are favorable to them only because of the CAISO's inability to accurately reflect such transactions due to a lack of information.

The IBAA proposal is a just and reasonable means of meeting the CAISO objectives (*i.e.*, protecting CAISO ratepayers from unjust and unreasonable prices and improving the representation of the IBAA in the Full Network Model) given the refusal of the IBAA Entities to provide data that would allow the CAISO to verify the location of external resources within the SMUD-TID IBAA that are dispatched to implement interchange transactions. In discussing the

---

[12] *See* Attachment E at 12 (indicating that the CAISO originally wanted each IBAA to provide detailed information and that in the Spring of 2007 the CAISO scaled back its approach in response to the concerns of the IBAA Entities).

[13] *See* the May 8, 2008 Municipal Proposal at 11, 14. The proposal was from the SMUD BA, the TID BA, and the TANC members and can be found at http://www.caiso.com/1fc2/1fc2d9bcd910.pdf.

[14] Exhibit ISO-3, Testimony of Dr. Harvey, at 22-23. Similarly, Dr. Hildebrandt states that the counterproposal of the IBAA entities: "is specifically designed to ensure that Market Participants have the ability to schedule imports and exports at ISPs where prices would be *most favorable* to them, without any requirements or consideration as to the actual source of the generation supporting these schedules. Thus, the IBAA counter proposal is specifically designed to permit scheduling practices that conflict with the fundamental concerns identified by the CAISO." Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 20 (emphasis added).

CAISO's long run desire to exchange detailed scheduling, generation, and load information with other BAAs, Dr. Harvey stated that the CAISO's goal:

> can only be achieved with the cooperation of adjacent Balancing Authority Areas that have a similar interest in improving reliability and reducing costs. While the CAISO pricing proposal for the SMUD-TID IBAA does not reflect the intended end state, *it is an improvement over the current scheduling and pricing mechanism, is better than the alternative proposed by the IBAA parties, and is a step forward toward the intended end state that ought to be taken. Until the end state system is implemented, the CAISO must operate the transmission system based on the best information available to it, and the current CAISO proposal will enable it to do so. In the absence of better information, the CAISO will make reasonable assumptions or approximations regarding the location of the resources supporting interchange transactions between the SMUD and TID Balancing Authority Areas and the CAISO*.[15]

The CAISO's MSC and Dr. Hildebrandt have opinions similar to that of Dr. Harvey. The MSC states that in the absence of detailed information on the day-ahead schedules of all generation units and inter-ties outside of the CAISO Balancing Authority Area that exert an influence on power flows in the CAISO BAA, the CAISO's "proposal of a single aggregate IBAA with an import and export price appears to be the best available way to obtain day-ahead schedules that are accurate predictions of real-time flows that do not involve significant monetary transfers from CAISO participants to these entities."[16]

D. Reliability Benefits of the IBAA Proposal

As described in more detail in the testimony of Dr. Scott Harvey, Dr. Eric Hildebrandt, and the panel testimony of Mark Rothleder and Dr. James Price, the location of resources matters under an LMP regime. This fact is true for resources internal to the CAISO Controlled Grid and for those resources external to the CAISO Controlled Grid used to implement interchange transactions. The locations of resources that support transactions internal to the CAISO Controlled Grid and the location of external resources that support import and export transactions all affect the CAISO's congestion management processes and the resulting LMPs. Failure to reflect, as accurately as possible, the location of the resources used to implement interchange transactions can result in less efficient utilization of the transmission system in the CAISO markets; less consistency between transactions in the CAISO markets and the physical operating needs on the CAISO Controlled Grid; greater differences between scheduled and actual flows on the CAISO Controlled Grid; a less reliable grid; less accurate LMPs; and inappropriate and unnecessary costs borne by CAISO ratepayers.

---

15 Exhibit ISO-3, Testimony of Dr. Harvey at 24-25 (emphasis added).

16 *See* Attachment I to this filing, the MSC's Opinion on Modeling and Pricing of Integrated Balancing Areas under MRTU ("*MSC Opinion*") at 2; *see also*, Exhibit ISO-2, Testimony of Dr. Hildebrandt at 16-17.

Under the CAISO's current zonal market regime, interchange transactions are modeled as if each associated external resource were located at an Intertie Scheduling Point. This approach works reasonably well given the limited congestion management functionality and network model of the current forward zonal market design. Under LMP, however, representing interchange transactions at Intertie Scheduling Points – particularly with regard to adjacent BAAs that have multiple points of interconnection with the CAISO BAA – will tend to compromise the effectiveness of congestion management in ensuring feasible schedules.

Because the CAISO neither controls the dispatch, nor knows the location of the generation and loads located within the IBAA that are dispatched to implement interchange transactions, the CAISO cannot ensure that an interchange transaction scheduled day-ahead at any particular Intertie Scheduling Point is consistent with the location of the generation and loads actually dispatched to implement the interchange transaction in real time. As a result, schedules that appear feasible in the day-ahead market may actually create very different flows in real-time and thus require the kinds of real-time operator actions that MRTU is intended to prevent.

By using a more accurate and reasonable representation of the locations of external resources used to implement interchange transactions in the CAISO's Full Network Model, the IBAA proposal will help to ensure that: (i) such interchange transactions are appropriately valued for purposes of managing congestion on the CAISO Controlled Grid, and (ii) there are not significant differences between scheduled flows and actual flows. Reducing the possibility of large differences between scheduled and actual flows will eliminate the infeasible schedule problem that plagued the pre-MRTU zonal market design and thus improve reliability.[17]

E. Market Incentive Improvements of the IBAA Proposal

The use of a single hub mechanism with default pricing points for interchange transactions between the CAISO and the SMUD-TID IBAA eliminates the inappropriate scheduling incentives that come with having multiple pricing points for interchange transactions between the CAISO and the IBAA.[18] According to Dr. Harvey, the concerns regarding inefficient scheduling incentives are not hypothetical; the problems have repeatedly manifested themselves in the eastern interconnection across scheduling points spanning much larger geographic and electrical distances than those at issue with the pricing of interchange between the CAISO and the SMUD and TID BAA.[19] In Dr. Harvey's opinion:

> [t]here is no question that if presented with different prices at alternative scheduling points with a single Balancing Authority Area, market participants

---

17 In the words of Dr. Harvey, more accurate predictions of the impact of imports on internal CAISO transmission constraints will reduce the potential for situations to arise in real-time in which transmission system flows are so different from those modeled in the day-ahead or hour-ahead commitment process that the CAISO either will not be able to solve the constraints with the units that are on-line, or the constraints will only be solved in real-time by curtailing scheduled interchange transactions. Exhibit ISO-3, Testimony of Dr. Harvey at 15.

18 *See* Exhibit ISO-2, Testimony of Dr. Hildebrandt at 16.

19 Exhibit ISO-3, Testimony of Dr. Harvey at 7.

> will schedule transactions along a contract path external to the Balancing Authority Area to the scheduling point with the most favorable price. This kind of behavior has been repeatedly observed and continues to be observed in other markets. There is no need to wait to see what happens in California.[20]

Dr. Harvey explains that because the price paid for power varies locationally based on the differential impact injections or withdrawals at each location would have on binding transmission constraints on the CAISO transmission system, it is necessary to model imports as being sourced at some location, so their impact on internal CAISO transmission constraints can be calculated.[21] Similarly, it is necessary to model exports as sinking at some location, so their impact on internal CAISO transmission constraints can be calculated.[22] However, if the location at which imports are modeled for the purpose of calculating congestion charges differs from the actual location at which generation would actually be increased to support the net imports, then the CAISO may be paying too much or too little (*i.e.*, causing too few imports to be scheduled) for those imports.[23]

The experience of the eastern RTOs as discussed by Dr. Harvey has been that entities will schedule imports at the pricing points with the highest prices even though the location and value of the power of the resources actually used to implement the transaction is lower. The CAISO's ratepayers should only pay, *e.g.*, $80 for power when they actually receive power valued at $80; they should not pay $80 for power and receive power valued at $30. The IBAA proposal ensures that an entity that schedules an interchange transaction with the CAISO from the SMUD-TID IBAA will not be paid a premium for power that in fact does not have a favorable impact on internal transmission constraints on the CAISO Controlled Grid.[24]

For any market participant that argues that the CAISO's default modeling and pricing proposal does not value their generation properly or is weighted inappropriately in favor of CAISO ratepayers, the CAISO explicitly has made the modeling and pricing proposal a "default" proposal in response to stakeholder comments. The IBAA proposal allows market participants to avoid the default modeling and pricing mechanism if they supply the CAISO with better information that allows the CAISO to verify the location and operation of the resources used to implement interchange transactions between the CAISO Controlled Grid and the IBAA. As explained by Dr. Hildebrandt of the CAISO's D M, the conditions and data requirements that must be met to receive non-default pricing appropriately places much of the burden of data preparation and verification on the participant, rather than on the limited resources of the CAISO DMM, and, potentially FERC's own Office of Enforcement.[25]

---

20 *Id*.

21 *Id*. at 16.

22 *Id*.

23 *Id*.

24 Exhibit ISO-3, Testimony of Dr. Harvey, at 26.

25 *See* Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 18.

In summary, the default pricing points in the CAISO's IBAA proposal are needed to protect California ratepayers within the CAISO BAA. Since the CAISO cannot force entities to provide more detailed information regarding the location and dispatch of resources external to the CAISO BAA, it must provide for a default pricing mechanism that protects CAISO ratepayers in the absence of such information.[26] The IBAA proposal uses the same mechanism employed by the RTOs in the east, represents a reasonable approach to protect consumers from being exposed to inappropriate prices, promotes accurate pricing or valuation for interchange transactions between the IBAA and the CAISO Controlled Grid, and makes the operation of the CAISO Controlled Grid more reliable.

II. BACKGROUND

In its decision conditionally authorizing the CAISO to proceed with MRTU, the Commission recognized that MRTU would repair the structural flaws in the California wholesale electric market that contributed to the California Energy crisis of 2000-2001.[27] The Commission concluded, *inter ala*, that MRTU:

- <u>Eliminates… infeasible schedules</u>. Market participants currently submit infeasible schedules for energy because there are no negative financial consequences to their doing so. Also, under the current tariff, the CAISO must accept infeasible day-ahead schedules that do not reflect actual transmission bottlenecks and operating limitations of generators because its computer software ignores these limitations. This is a serious problem that forces the CAISO's transmission grid operators to scramble in real-time to correct infeasible day-ahead schedules. MRTU will ensure that day-ahead schedules are physically feasible because its new computer software will fully consider all transmission bottlenecks and generator operating limitations. This will make the CAISO's system more reliable.

- <u>Uses a more comprehensive model of the transmission grid</u>. The CAISO currently decides which resources will be used for reserves (ancillary services) in a manner that is independent from its energy dispatch decisions. This results in less efficient use of generation capacity. Under MRTU, the CAISO will consider at the same time which resources to use for energy and which resources to use for reserves. This will create more efficient dispatch. Meeting demand and reserve requirements from the lowest cost set of generators will benefit customers by keeping prices down.

* * *

---

26 The entities that possess this needed information can avoid default pricing by entering into an alternative arrangement with the CAISO that provides the CAISO with the information that it needs to accurately model interchange transactions between the two BAAs.

27 *September 2006 Order* at P 5

- Adopts locational marginal pricing for suppliers and for improved congestion management: Under locational marginal pricing, or LMP, prices in wholesale markets vary by location and time, based on the true physical limitations of the transmission grid, and reflect the incremental cost of meeting customer demand at each location. Locational marginal pricing will communicate the true market value of electricity at each location, as well as the cost of alleviating congestion between any two locations. This will create financial incentives to dispatch the lowest cost energy, when considering all transmission bottlenecks. In the long-term, by making energy and congestion prices more transparent, locational marginal pricing will help encourage transmission and generation investment at appropriate locations, as well as demand response. It bears emphasis that the CAISO's version of locational marginal pricing is aimed primarily at suppliers who will be paid their location-specific price. Wholesale customers will be insulated from the location-specific prices because they will continue to pay an aggregated zonal price.[28]

A. The Need for an Accurate Full Network Model

The accuracy of the Full Network Model is essential to more fully realizing the benefits of MRTU's LMP-based market design and remedying the CAISO's flawed congestion management process.[29] The Full Network Model is used in the Day-Ahead, Real Time, and transmission rights markets (*i.e.*, the Congestion Revenue Right or "CRR" markets). To realize its purpose of facilitating congestion management and providing accurate LPM prices, the Full Network Model must reflect, as accurately as possible, the topology of the CAISO Controlled Grid, including associated transmission constraints.

The Full Network Model enables the CAISO to conduct power flow analyses to identify transmission constraints in the optimization of the CAISO Markets.[30] By ensuring consistency between transactions in the CAISO markets and the physical operating needs on the CAISO Controlled Grid, the Full Network Model ensures that there are not large differences between scheduled flows and actual flows. Reducing differences between scheduled and actual flows eliminates the infeasible schedule problem that was prevalent with the pre-MRTU zonal market design.[31]

---

28 *Id*. at P 10.

29 As noted by the CAISO's Market Surveillance Committee ("MSC"): "One lesson from the current zonal market design in California is that there is a significant risk of adverse unintended consequences from attempts to simplify the full network model in the day-ahead market and still obtain final energy schedules that are accurate representations of real time power flows." *MSC Opinion* at 4.

30 *See* MRTU Tariff § 27.5.1.

31 The infeasible scheduling problem arises when the CAISO uses a model of the CAISO Controlled Grid for scheduling purposes that does not reflect the actual transmission bottlenecks and operating limitations of the transmission system, or the submitted schedules do not reflect the actual locations of the scheduled supply and demand resources. Either type of inaccuracy can result in the CAISO accepting day-ahead schedules that will result in infeasible real-time power flows. Infeasible schedules are a serious problem that can force the CAISO's

The Full Network Model is a detailed mathematical representation of the physical transmission system operated by the CAISO and it represents the constraints and interfaces of the CAISO Controlled Grid. The Full Network Model also incorporates a representation of the interconnections between the CAISO and other BAAs in neighboring states as well as those BAAs within California that are not part of the CAISO Controlled Grid.[32] Interchange transactions between the CAISO BAA and the other BAAs can have a significant effect on the flows and constraints on the CAISO Controlled Grid and, therefore, in order to manage congestion as accurately as possible on the CAISO Controlled Grid, it is important to, as accurately as possible, reflect the affect of interchange transactions on the CAISO Controlled Grid in the Full Network Model.

The improvement in the accuracy of the Full Network Model proposed in this filing also increases the accuracy of the resulting LMPs because the LMPs are one of the main outputs of the Security Constrained Unit Commitment ("SCUC") based optimization, which uses the FNM to arrive to the market solution. It is fundamental to a system using LMPs that the LMPs provide accurate signals to market participants to operate in a manner consistent with reliable grid operation and economic efficiency. In addition, the Full Network Model is used in the allocation and auction of CRRs so that CRRs (and the hedge against congestion costs that CRRs provide) reflect as closely as possible the grid constraints that will actually be enforced in the Day-Ahead and Real Time Markets.

As previously recognized by the Commission, it is very important for the CAISO to use a Full Network Model that is as accurate as possible. The Full Network Model is used across all market time-frames and is intended to ensure that market outcomes reflect the efficient and reliable Real-Time operation of the transmission grid.

B. The MRTU Filing, the September 21, 2006 Order and IBAAs (formerly referred to as "Embedded Control Areas" and "Adjacent Control Areas")

---

transmission grid operators to scramble in real-time to correct infeasible day-ahead schedules. The promise of the MRTU market design is that it will ensure that day-ahead schedules are physically feasible because the Full Network Model will consider all transmission bottlenecks and generator operating limitations and therefore will make the CAISO's system more reliable. The IBAA proposal is intended to reduce the submission of infeasible schedules for interchange transactions by: (a) more accurately reflecting the external SMUD-TID IBAA network in the Full Network Model, and, (b) reasonably approximating the location of the external resources used to implement interchange transactions in the absence of more detailed information.

[32] The CAISO notes that North America Electric Reliability Corporation ("NERC") and the WECC now use the terms Balancing Authority ("BA") and Balancing Authority Area instead of Control Area Operator and Control Area, respectively. To match the NERC and WECC terminology, the CAISO replaced: (i) the term "Control Area Operator" with "Balancing Authority", (ii) the term "Control Area" with "Balancing Authority Area", and (iii) the terms "Embedded Control Area" and "Adjacent Control Area" with the term "Integrated Balancing Authority Area" or "IBAA". To the extent the CAISO quotes or refers to: (i) tariff language previously placed on file with the Commission, (ii) previous Commission orders, and/or (iii) previous CAISO documents, it may continue to use the terms Control Area and Control Area Operator in this transmittal letter.

As noted in the previous section: (i) the Full Network Model is a representation of the CAISO Controlled Grid and CAISO BAA that enables the CAISO to identify transmission constraints for the optimization of the CAISO Markets, and (ii) external transmission systems are modeled in the Full Network Model to support the commercial requirements of the CAISO MRTU markets including the congestion management process. In the *September 2006 Order*, the Commission conditionally-approved Section 27.5 of the MRTU Tariff dealing with the Full Network Model and noted the CAISO's description of the Full Network Model as providing "an accurate representation of the CAISO Control Area and all control areas that are either embedded within the CAISO Control Area or adjacent to the CAISO Control Area [*i.e.*, IBAAs] and within the State of California."[33]

As filed on February 9, 2006 and as conditionally-approved in the *September 2006 Order*, section 27.5.3 read as follows:

> **27.5.3 Embedded Control Areas and Adjacent Control Areas.**
> To the extent sufficient data is available or adequate estimates can be made for the embedded Control Areas and adjacent Control Areas, the Full Network Model will include a full model of embedded Control Areas and adjacent Control Areas used for power flow calculations and congestion management in the CAISO Markets Processes. The CAISO monitors but does not enforce the network constraints for embedded Control Areas or adjacent Control Areas in running the CAISO Markets Processes. The CAISO models the resistive component for transmission losses on embedded Control Areas and adjacent Control Areas but does not allow such losses to determine LMPs.[34]

In the *September 2006 Order*, the Commission supported the CAISO's commitment to include more information concerning adjacent and embedded control areas (now IBAAs) in the Full Network Model as soon as possible.[35] The Commission agreed that the CAISO should operate the California grid using the most accurate model of internal and external areas that can be developed.[36] In addition, the Commission directed the CAISO to work with external control areas to develop the model more fully in the future, but noted that the CAISO can only model external areas to the extent it has the information to do so.[37]

Pursuant to the Commission's direction and due to the physical characteristics of the SMUD BAA and the TID BAA, the CAISO focused its efforts to model these areas as an IBAA. As explained further below, the SMUD-TID BAAs are uniquely situated because together they

33 *See September 2006 Order* at PP 45, 46. As noted earlier, the term "CAISO Control Area" is referred to as the "CAISO BAA" and "embedded" and "adjacent control areas" are referred to as "Integrated Balancing Authority Areas" or "IBAAs".

34 *See* MRTU Tariff § 27.5.3 (as filed on February 9, 2006).

35 *September 2006 Order* at P 45.

36 *Id*.

37 *Id*. *See also* MRTU Tariff § 27.5.3.

have the most interties with the CAISO BAA and are the most closely integrated as reflected in the degree of parallel flows between the areas. As early as spring 2006, after filing its MRTU Tariff in February 2006, the CAISO had announced the need to model the SMUD and TID BAAs, which preceded the *September 2006 Order*, in which the Commission endorsed the CAISO approach. For example, on July 31, 2006, the CAISO published a draft BPM for the Full Network Model indicating that the SMUD; Western, MID and TID are Adjacent Control Areas that may be included in the Full Network Model because they have transmission facilities that operate in parallel with the CAISO Control Area and are highly interconnected to the CAISO Control Area.[38] A detailed accounting of the CAISO's efforts to further enhance the Full Network Model, develop its IBAA proposal, and consult with the IBAA is included in Attachment E to this Transmittal Letter.

III. The Stakeholder Process

The CAISO is grateful for the effort of its stakeholders in participating in this process which involved difficult issues associated with the modeling and pricing of interchange transactions with the IBAA. While all appeared to share a common goal of utilizing the most accurate Full Network Model in managing congestion on the CAISO Controlled Grid,[39] there was a divergence of opinion on how this objective could and should best be accommodated. Since the Commission's *September 2006 Order* conditionally approving the CAISO's MRTU market design and the subsequent Seams Technical Conference, the CAISO has continued to address seams issues and has worked closely with Balancing Authorities ("BAs"), especially those BAs whose areas are embedded within or adjacent to the CAISO Controlled Grid (*i.e.*, the entities within the SMUD and TID BAAs that are subject to the instant proposal).[40]

Attachment E to this Transmittal Letter contains a detailed timeline and description of the CAISO's development of the IBAA proposal.[41] Attachment E sets forth the CAISO's

---

[38] *See* § 2.2.5 of July 31, 2006 BPM for the Full Network Model at page 2-7. The BPM can be found at (http://www.caiso.com/1841/1841c80437f00.pdf).

[39] For example, Western Power Trading Forum ("WPTF") states the CAISO should "[m]odel more accurately the flows on the COTP system, thereby creating accurate prices at the interchange points and preventing the overcharge of congestion and losses given respective loop flows on the respective systems." WPTF April 28, 2008 comments at 1 (http://www.caiso.com/1fb8/1fb899d913f40.pdf). Western Area Power Administration "does not object with the CAISO's desire to improve the accuracy with respect to the way it models its system operations in the state of California." Western April 28, 2008 comments at P 10 (http://www.caiso.com/1fb9/1fb991ac33820.pdf). Powerex "agrees with the desire to model the system more accurately to manage congestion and flows on the CAISO Grid." Powerex April 28, 2008 Comments at 1-3 (http://www.caiso.com/1fb8/1fb8968068e20.pdf). California Municipal Utilities Association (CMUA) "supports constructive efforts to improve predictive modeling and increase pricing accuracy inside the CAISO markets." CMUA April 28, 2008 Comments at 1 http://www.caiso.com/1fb9/1fb992f841290.pdf.

[40] *See* Attachment E to this Transmittal Letter "Summary of the IBAA Development, Consultation, and Stakeholder Process" ("*Attachment E*").

[41] The CAISO has long acknowledged the need to appropriately model and price interchange transactions between the CAISO and neighboring Balancing Authority Areas and that the consultation and stakeholder processes goes as far back as the CAISO's original MRTU design proposal (then referred to as the CAISO's Comprehensive Market Redesign or "MD02 Proposal"). Beginning with the MD02 Proposal in 2002, the CAISO acknowledged its

development, consultation, and stakeholder process from the original filing of the MRTU (then "MD02") proposal on May 1, 2002, through the filing of the instant IBAA proposal. Attachment E also includes a description of the Seams Technical Conference held on December 14-15, 2006; the seams reports filed by the CAISO and others over the last year and a half; and a table setting forth the milestones in the specific IBAA development, consultation and stakeholder process.[42]

The CAISO initiated an internal process to develop the design and implementation details for modeling and pricing IBAAs in early 2007.[43] Once the CAISO developed what it believed was a reasonable framework, it began to work with potential IBAAs entities to secure their support for the modeling and pricing of interchange transactions between an IBAA and the CAISO. At the same time that the CAISO was developing its initial IBAA proposal, the CAISO began to engage external Balancing Authorities around the West regarding use of a detailed Full Network Model and data requirements associated with its use. In addition, the CAISO engaged these same entities in data sharing arrangements necessary to support the newly-adopted mandatory NERC reliability standards. While the CAISO agrees with the Commission that the "need for better data exchange among control areas in the West is not a seams issue related to MRTU,"[44] in an effort to move towards better data exchanges with its own neighbors, and starting with an area of the interconnected grid which the CAISO had identified required better modeling the most, the CAISO sought to solicit from all the neighboring BAs more cooperative involvement in data exchanges.

CAISO concentrated its efforts the most with the SMUD and TID BAAs, but as evidenced by the quarterly reports on seams issues,[45] by the fourth quarter of 2007, the discussions between the CAISO and the proposed IBAA Entities were no longer moving toward resolution. At that time, based on opposition of the IBAA Entities to the CAISO's then-proposed IBAA proposal (and because of the then-impending February 1, 2008, MRTU start date), the CAISO determined that it was appropriate and prudent to initiate a broader stakeholder discussion regarding the IBAA proposal prior to MRTU start up. Beginning with the issuance of two IBAA whitepapers on December 14, 2007, the CAISO began the broader stakeholder effort.[46]

---

intent to treat interchange transactions in a manner consistent with the CAISO's proposed LMP methodology. *See Attachment E* at 1-2.

42 *See Attachment E* and the table at 19-22.

43 The CAISO's original thinking regarding the modeling and pricing for IBAAs is detailed in Appendix 3 to the CAISO's December 14, 2007 "Discussion Paper Modeling and Pricing Integrated Balancing Authority Areas Under the California ISO's Market Redesign and Technology Upgrade Program" posted on the CAISO website at http://www.caiso.com/1cb4/1cb4e1a154060.pdf.

44 April 20 Order at P 208.

45 *See Attachment E* at 14-24 and the table at 28-31.

46 *See* the December 14, 2007 "Discussion Paper – Modeling and Pricing Integrated Balancing Authority Areas Under the California ISO's Market Redesign and Technology Upgrade Program" ("*Modeling & Pricing Discussion Paper*"); and the December 14 ,2007 "MRTU Release 1 Implementation of Preferred Integrated Balancing Authority Area Modeling and Pricing Options" ("*Release 1 Implementation of IBAA Modeling & Pricing Options*"). The *Modeling & Pricing Discussion Paper* can be found at

The stakeholder process included the submission of numerous written comments to the CAISO over a series of five rounds of comments[47], many of which the CAISO answered explicitly in writing or more generally in its subsequent stakeholder meetings.[48] As reflected in Attachment E to this Transmittal Letter, the CAISO held numerous Conference Calls and In-person Meetings. The CAISO also accommodated requests by stakeholders to hold break-out sessions that focused on specific issues that seemingly impacted only a smaller group of stakeholders.[49]

The CAISO appreciates the efforts of all of its market participants to engage on the IBAA proposal and other important MRTU seams issues. Throughout the stakeholder process several issues were raised by stakeholders. In developing the CAISO's final proposal (*i.e.*, the instant filing) the CAISO incorporated the suggestions of some stakeholders and rejected the suggestions of others.[50] The CAISO has a responsibility to develop market rules that, in its opinion, will: (i) best foster full and fair competition, (ii) promote the efficient use of generation and transmission resources, and (iii) not create inappropriate incentives that result in ratepayers bearing unreasonable costs. The CAISO also notes that the final proposal has been greatly influenced by the guidance and expertise of the CAISO's D MM, the CAISO's MSC composed of outside economic experts, and the expertise of Dr. Scott Harvey with his knowledge of how the Eastern RTOs have addressed similar interchange issues as well as his knowledge of the MRTU market design.

As described in further detail in Attachment E, the following actions were a direct response to the specific stakeholder comments:

(i) The CAISO extended the stakeholder process and deferred action (*i.e.*, obtaining CAISO Board of Governors approval and filing with the Commission) on the IBAA proposal three times in response to stakeholder concerns;

(ii) The CAISO agreed to file the IBAA proposal as a new Section 205 filing and not as a compliance proposal due to the pricing provisions of the proposal;

(iii) The CAISO developed and committed to a stakeholder process regarding changes to the existing IBAA (assuming approval) and the creation of a new IBAA;

---

http://www.caiso.com/1cb4/1cb4e1a154060.pdf. The *Release 1 Implementation of IBAA Modeling & Pricing Options* paper can be found at http://www.caiso.com/1cb4/1cb4e0984a670.pdf.

47 *See* Attachment E at 25, 28-31.

48 All stakeholder comments that have been submitted to the CAISO are posted at: http://www.caiso.com/1f50/1f50ae5b32340.html.

49 IBAA questions by stakeholders and answer to the stakeholder questions by the CAISO can be found at http://www.caiso.com/1f50/1f50ae5b32340.html#1f5e90576130.

50 For a discussion of the alternatives the CAISO considered, *see* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 48-58.

(iv) The CAISO assessed and developed a proposal in response to stakeholder concerns regarding the impact of the IBAA proposal on CRRs; and

(v) The CAISO included the availability of alternative modeling and pricing arrangements (*i.e.*, Market Efficiency Enhancement Agreements) for interchange transactions with the IBAA that are different from the default modeling and pricing arrangements so long as the CAISO is provided with better information that allows the CAISO to verify the location and operation of the resources used to implement interchange transactions between the CAISO Controlled Grid and the IBAA.

Based on comments in the stakeholder process and public comments at the CAISO Board of Governors meeting when the IBAA proposal was approved, the IBAA will be supported by a wide cross section of stakeholders that includes the investor-owned utilities in California and other entities in the West that engage in import and export transactions using the CAISO Controlled Grid. As discussed in greater detail in IV.E, *infra*, the most significant opposition to the IBAA proposal comes from the municipal entities in northern California, including the entities located within the SMUD and TID BAAs and the participants in the California Oregon Transmission Project ("COTP").

IV. DISCUSSION

A. The Integrated Balancing Authority Area Proposal for the SMUD BAA and the Turlock BAA

The CAISO's proposal combines the SMUD and TID BAAs into a single IBAA for modeling and pricing the interchange transactions with the IBAA. The proposal will improve the CAISO's assessment of the impacts of interchange transactions on the CAISO Controlled Grid to and from the SMUD-TID IBAA and will increase the accuracy of the congestion management process on the CAISO Controlled Grid. By using a single hub approach with one default pricing point for all imports and one default pricing point for all exports, the IBAA proposal avoids creating unjust and unreasonable scheduling and pricing incentives that result from: (i) having multiple price locations for transactions between the IBAA and the CAISO Controlled Grid, and (ii) the incentive to schedule at the most favorably priced locations irrespective of the location of the resources actually dispatched to implement the transaction. The proposal also allows for alternative pricing arrangements if an entity agrees to provide the CAISO with additional information sufficient to support the alternative pricing arrangement and allow the CAISO to verify the location and operation of the resources within the IBAA that are actually used to implement interchange transactions.

In addition, by having a more accurate representation of the location and operation of external resources used to implement interchange transactions in the CAISO's Full Network Model, the IBAA proposal helps to ensure that there will not be significant differences between day-ahead scheduled flows and actual flows in real time. Reducing the possibility of large differences between scheduled and actual flows will eliminate the infeasible schedule problem that was prevalent with the pre-MRTU zonal market design. Moreover, the RTOs in the east all use "proxy bus" mechanisms to model and price interchange transactions and the CAISO's proposal is consistent with the proxy bus arrangements in place in the east.[51] In short, the IBAA proposal is necessary to more appropriately manage congestion on the CAISO Controlled Grid and to protect California consumers from having to pay inappropriate prices and unnecessary uplift costs associated with interchange transactions between the IBAA and the CAISO Controlled Grid.

1. The Design of the IBAA Proposal

Under the CAISO's proposal, there is one default modeling and pricing point for imports and another default modeling and pricing point for exports. For all imports to the CAISO (*i.e.*, an import from the IBAA scheduled at one of the CAISO's twelve Intertie Scheduling Points with the IBAA), the impact of such imports on the CAISO Controlled Grid would be determined by modeling the transaction as if the resources within the IBAA whose output was increased to support the import were located at the Captain Jack Substation. Specifically, the CAISO will create an external, virtual System Resource in the Full Network Model located at the Captain Jack substation and, when a market participant schedules an import from the IBAA at one of the Intertie Scheduling Points between the CAISO Controlled Grid and the IBAA, the CAISO will map the schedule for modeling and pricing purposes to the System Resource located at the Captain Jack substation (*i.e.*, model the schedule as an injection at the Captain Jack Substation). The default LMP used to price the imports will be the LMP calculated at the System Resource / proxy bus location at the Captain Jack substation.

For all exports from the CAISO Controlled Grid to IBAA, the default modeling and pricing process will use a System Resource / proxy bus in the Full Network Model that is located at the SMUD Hub.[52] When a market participant schedules an export from the CAISO to the IBAA at one of the various Intertie Scheduling Points between the CAISO Controlled Grid and the IBAA, the CAISO will map the schedule to (or model the scheduled injection at) the System Resource located at the SMUD Hub. The default LMP used to price the exports will be the LMP calculated at the System Resource / proxy bus located at the SMUD Hub.

It is important to note that prior to deciding on the single hub proposal, the CAISO contemplated a multiple hub proposal with two IBAAs – one for the SMUD BAA and a separate IBAA for the TID BAA. The SMUD IBAA would have had 5 pricing points or sub-hubs: (i) a SMUD hub, (ii) a Western hub, (iii) a Modesto Irrigation District ("MID") hub, (iv) a City of

---

[51] *See* Exhibit ISO-3, Testimony of Dr. Harvey at 39-42.

[52] The SMUD Hub is comprised of the following transmission buses (using CAISO naming conventions) and will have the following Intertie Distribution Factors ("IDF"): (1) 37005_ELVERTAS 230kV with an IDF of 0.14; (2) 37010_HURLEY S 230kV with an IDF of 0.31; (3) 37012_LAKE 230kV with an IDF of 0.19; and (4) 37016_RNCHSECO 230kV with an IDF of 0.36. *See* the SMUD Hub buses and IDFs in the January 22, 2008 CAISO Power Point Presentation Update "Modeling and Pricing of Integrated Balancing Authority Areas" at slide 38 ("January 22, 2008 Power Point Presentation"). The *January 22, 2008 Power Point Presentation* can be found at (http://www.caiso.com/1f56/1f56eb9739860.pdf).

Roseville ("Roseville") hub, and (v) a hub at the Captain Jack Substation.[53] The TID IBAA would have had one pricing point or hub. As noted above, under the CAISO's single hub proposal, the SMUD hub is the default modeling and pricing point for all exports to the IBAA and the Captain Jack Substation is the default modeling and pricing point for all imports to the IBAA.

From a modeling perspective, a single hub approach can be less accurate than the CAISO's original multiple hub approach with accurate identification by Market Participants of the resources actually supporting their scheduled interchange transaction and use of this information to assign transactions to the appropriate hub for pricing and modeling purposes. A single hub approach will, however, provide a more accurate model than a multiple hub approach in which Market Participants are permitted to use contract path schedules to deliver power to the highest priced hub, without regard to the location of the generation supporting the transaction.[54] Moreover, the CAISO IBAA proposal will function as a multiple hub approach, and realize the associated modeling benefits, to the extent that the relevant market participants enter into alternative pricing arrangements with the CAISO.

The CAISO cannot ignore the potential negative pricing consequences of a multiple hub proposal. Based on the collective input from Dr. Hildebrandt in the CAISO's DMM,[55] the opinion of the CAISO's MSC,[56] and the testimony of Dr. Harvey regarding the experience of the

---

53 *See* December 14, 2007 "Discussion Paper - MRTU Release 1 Implementation of Preferred Integrated Balancing Authority Area Modeling and Pricing Options" ("IBAA Implementation Discussion Paper") at 5; *see also*, December 14, 2007 "Discussion Paper – Modeling and Pricing Integrated Balancing Authority Areas Under the California ISO's Market Redesign and Technology Upgrade Program" ("Modeling & Pricing Discussion Paper"). The *IBAA Implementation Discussion Paper* can be found at (http://www.caiso.com/1cb4/1cb4e0984a670.pdf) and the *Modeling & Pricing Discussion Paper* can be found at (http://www.caiso.com/1cb4/1cb4e1a154060.pdf).

54 Dr. Harvey notes that while it might seem that the introduction of multiple proxy buses that allows market participants to choose the proxy bus used to schedule their transactions might provide a better approximation of system impacts than a single proxy bus model, this is not the case; in fact, just the reverse will generally be the case. *See* Exhibit ISO-4, Scott Harvey, "Proxy Buses and Congestion Pricing of Inter-Balancing Authority Area Transactions" June 9, 2008 at 8. Dr. Harvey explains that a multiple proxy bus design will likely provide market participants with financial incentives to schedule transactions such that the proxy bus used to schedule their transactions does not reflect the actual location of the generation that would be dispatched to support the transaction. *Id*. Moreover, this effect is systematic, causing a system operator employing a multiple proxy bus system to price scheduled net interchange in a manner that incurs costs that must be recovered from market participants in uplift charges. *Id*. Dr. Harvey concluded that "despite the approximations inherent in a single proxy bus system, no more than one proxy bus should be established to price a single interchange schedule with an adjacent balancing authority area." *Id*.

55 *See* Exhibit ISO-2, Testimony of Dr. Hildebrandt at 8-16.

56 *See* Attachment I, *MSC Opinion* at 5 (indicating that the MSC supports a single pricing location for the SMUD-TID IBAA region). The MSC states that a single hub approach:

> should provide entities transferring energy in and out of the CAISO BAA from and to the SMUD/WAPA/MID/TID region with an incentive to schedule resources in a least-cost manner. This pricing mechanism will at least eliminate the incentive to schedule power in a way that takes advantage of the inadequacies of the WECC-wide balancing process as it affects CAISO markets. Firms will have a strong incentive to schedule imports to the CAISO BAA from the least cost (to

RTO's in the east dealing with the issue of pricing interchange transactions under an LMP regime,[57] the CAISO believes the single-hub approach is the most appropriate design to use at the beginning of the MRTU markets.

Dr. Hildebrandt and Dr. Harvey explain that the benefits of a multiple hub approach are almost entirely dependent on having an accurate representation of the marginal resources actually supporting the import and export schedules and bids submitted by market participants.[58] Furthermore, Dr. Hildebrandt and Dr. Harvey explain that due to the impacts of congestion within the CAISO system on the LMPs used to settle imports and exports, participants would have a natural financial incentive to submit schedules and bids at the location with the highest price for imports and the location with the lowest price for exports and that such scheduling activity could negate the congestion management benefits of a multiple hub approach or even exacerbate congestion.[59]

The single hub proposal protects CAISO ratepayers from unreasonable charges and addresses the lack of information the CAISO will have regarding the location and operation of external resources used to implement interchange transactions with the SMUD-TID IBAA. The single hub proposal essentially eliminates the poor scheduling incentives associated with multiple pricing points.[60] In addition, the single hub proposal will still improve modeling accuracy as compared to radial modeling at each of the twelve Intertie Scheduling Points between the CAISO and the IBAA and it will help to eliminate the infeasible schedule problem that was prevalent with the pre-MRTU zonal market design with regard to interchange transactions between the IBAA and the CAISO Controlled Grid.

2. Alternative Pricing Arrangements

As noted previously, if any market participant believes that the default rules will not appropriately price or reflect the value of their interchange transactions, they may obtain alternative pricing arrangements by providing the CAISO with more detailed information that enables the CAISO to verify the location and operation of the resources within the IBAA that actually are dispatched to implement the interchange transactions. This option and the criteria for entering into such an agreement are set forth in proposed MRTU Tariff section 27.5.3.2.

---

them) location in their region because they will receive the same price for imports regardless of where these imports come from. Similar logic applies to the case of withdrawals.

Id.

57 *See* Exhibit ISO-3, Testimony of Dr. Harvey at 7.

58 *See*, *e.g.*, Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 8 (where Dr. Hildebrandt notes that the potential congestion management benefits of the sub hub approach depend *entirely* on having an accurate representation of the marginal System Resource (*e.g.*, SMUD Hub, Western Hub, Captain Jack, etc.) actually supporting the import and export schedule and bids submitted by Market Participants)

59 *Id*.

60 Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 16.

In addition, in response to stakeholder comments, the CAISO agreed to provide a stakeholder process before finalizing such arrangements and filing them with FERC.[61] In order to enter into such an agreement, the CAISO must demonstrate that there are market efficiencies and enhancements obtained through such an arrangement. This provides an entity that has the data to make such an approach feasible with the opportunity for a more favorable pricing structure. The CAISO has labeled such alternative agreements as "Market Efficiency Enhancement Agreements" ("MEEA").[62]

3. The Proposal Will Have No Effect on Non-CAISO Controlled Grid Facilities, WECC Contract Path Scheduling Procedures, or WECC Interchange Transaction Checkout Procedures

It is important to recognize that the only purpose of modeling and pricing interchange transactions between the CAISO and the highly integrated SMUD and TID BAAs is to better assess the impacts of such transactions on *the CAISO Controlled Grid*.[63] The IBAA proposal and the location of external System Resources or pricing points *does not* value (or charge for) transmission service over non-CAISO Controlled Grid facilities.[64] The IBAA proposal also does not manage congestion on, or charge for losses over, the transmission facilities within the IBAA.[65] Transmission service over and any constraints within the IBAA systems are scheduled, priced and managed by the transmission system operators within the IBAA (*i.e.*, the transmission operators within the SMUD and TID BAAs).

The CAISO will enforce thermal and capacity constraints on the interties between the CAISO Controlled Grid and the IBAA as necessary for the reliable operation of the CAISO Controlled Grid. However, the IBAA will be responsible for congestion management within its own network. The CAISO will not enforce transmission constraints within the IBAA and will only address marginal losses within the CAISO footprint.[66] In other words, the LMPs produced in the CAISO markets will reflect conditions on the CAISO Controlled Grid, but will not attempt to reflect the impact of congestion within the IBAA. The CAISO will not be managing congestion within, or attempting to reveal prices internal to, the IBAA. While the CAISO will

---

[61] *See* Proposed MRTU Tariff § 27.5.3.2.

[62] *See* Proposed MRTU Tariff, Appendix A, Master Definition Supplement (definition of Market Efficiency Enhancement Agreement).

[63] The IBAA proposal also does not interfere with the rights under existing transmission contracts ("ETCs") or transmission ownership rights ("TORs"). These issues are discussed in more detail in the Panel Testimony of Mark Rothleder and Dr. James Price. *See* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 73-81.

[64] *See* Exhibit ISO -1, Testimony of Mr. Rothleder and Dr. Price at 76-79.

[65] *See* Exhibit ISO-3, Testimony of Dr. Harvey, at 20-21.

[66] Although transmission losses within the IBAA (and the losses on the Interties between the IBAA and other BAAs) will be fully accounted for in power flow calculations, the marginal impact of those losses will be ignored in the loss penalty factor calculations for setting the CAISO's LMPs. This is done because the IBAA is responsible for the transmission losses within its network. The contributions to the loss penalty factors from network branches within the IBAA (and from each of the IBAA Interties) will be ignored by setting these contributions to zero.

calculate LMPs at the applicable external System Resources, the LMPs will be representative of the value of power injections at those locations for purposes of managing congestion and losses only on the CAISO Controlled Grid.

Although network constraints within the IBAA will not be enforced, any constraint violations observed will be reported by the CAISO's market applications. If transmission overloads are observed in the Day-Ahead or Real-Time Market within the IBAA (or at the Intertie boundaries), the CAISO will communicate such events to the SMUD BA and TID BA and will coordinate with the respective BAs regarding any manual re-dispatch that is necessary in real-time. Consistent with Section 34.9.1 of the MRTU Tariff and pursuant to coordinated operating procedures, if the SMUD BA and TID BA are unable to resolve the overloads in real-time on its own, thereby posing a threat to reliability or creating a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system modeling, the CAISO will consider, based on operational discussions with the BAs, whether to issue Exceptional Dispatches to resources within the CAISO BAA to assist in resolving the overloads.

The LMPs that result from the default single hub pricing proposal and any alternative arrangements entered into by the CAISO will be applied at locations (PNodes) that are either internal to the CAISO Controlled Grid or at Intertie Scheduling Points that represent the points of interconnection where CAISO Controlled Grid facilities interconnect with non-CAISO Controlled Grid facilities. While obvious, it is important to emphasize in responding to the arguments of the IBAA Entities (discussed in Section IV.E. herein), that the LMPs will be applied only to billing determinants associated with *service over CAISO Controlled Grid facilities* (*i.e.*, imports to, exports from, and transactions internal to the CAISO Controlled Grid).

In addition, it is also important to note that market participants will still be able to schedule at the same Intertie Scheduling Points that exist today and the IBAA proposal does not change the Western Electric Coordinating Council ("WECC") contract path scheduling procedures or WECC interchange checkout procedures.[67]

4. The Choice of the Default Pricing Points is Reasonable

Under the CAISO's IBAA proposal the default pricing location for imports from the IBAA is the Captain Jack substation and the default location for exports is the SMUD Hub. There are a number of reasons for choosing these default locations.

a. The Default Locations are Likely Points at Which the Poor Scheduling Incentives of a Multi-Hub Approach Would Manifest Themselves And Reduce the Likelihood of Circular Schedules and Artificial Price Differences Between the Malin and Captain Jack Substations

[67] Exhibit ISO -1, Panel Testimony of Mr. Rothleder and Dr. Price, at 72; Exhibit ISO-3, Testimony of Dr. Harvey at 9.

The default pricing locations are likely points at which the inefficiencies and the poor scheduling incentives would have manifested themselves under the CAISO's original six hub proposal. During a typical period of north-to-south congestion between Northern California and the Pacific Northwest, a schedule associated with an increase in output from a generator in the SMUD hub could provide significant congestion management benefits, while a schedule associated with an increase in imports from the Northwest on the COTP or the other elements of the California Oregon Intertie ("COI") could exacerbate congestion on the CAISO Controlled Grid.[68]

During such a period, the LMPs would tend to be higher for import schedules mapped back to the SMUD or Western hubs than for imports mapped back to the Captain Jack sub-hub.[69] In this circumstance -- higher prices at the SMUD or Western hubs, coupled with lower prices at the Captain Jack hub -- would create an incentive for any additional supplies from the Northwest being imported on COTP to ultimately be scheduled as imports from the SMUD or Western sub-hubs.[70] This activity could include "circular" import and export schedules allowing the scheduling entity to "sell low" and "buy high."[71] Dr. Hildebrandt states that:

> [a] variation of such circular scheduling patterns would be that exports at the Malin inter-tie from CAISO into the Bonneville Power Authority ("BPA") might be used – directly or indirectly – to support additional imports into the SMUD IBAA at Captain Jack, which could then in turn be used to support additional imports back into the CAISO via schedules mapped to a higher priced sub hub within the SMUD and TID IBAA (such as SMUD or Western).[72]

By choosing the Captain Jack and SMUD hub default locations, the CAISO eliminates the "circular scheduling" concern discussed by Dr. Hildebrandt.[73] In particular, the default locations reduces the likelihood that Market Participants will take advantage of potential artificial price differences between Captain Jack and the Malin Intertie Scheduling Point (Malin is the Intertie Scheduling Point between the CAISO and BPA) that could occur if a different and higher priced default location were used for imports to the CAISO from the SMUD-TID IBAA.[74]

---

[68] *See* Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 7.

[69] *Id*. at 9.

[70] *Id*. Dr. Hildebrandt notes that in addition to requiring that CAISO Market Participants overpay for these imports relative to their impact on congestion within the CAISO system, this could exacerbate congestion within the CAISO system in real time, and thereby require the CAISO to redispatch other resources and incur additional redispatch costs in the CAISO's real time market.

[71] *Id*.

[72] *Id*. at 10,

[73] *See* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 58; *see also* Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 9-11.

[74] *See* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 58-59. Mr. Rothleder and Dr. Price explain that the CAISO expects that the prices at the Captain Jack System resource and the Malin substation will typically be the same when the scheduling limit at Malin is not binding. *Id*. at59. This is because Captain Jack

b. The CAISO Must Accept All Qualified Offers for Power and Has an Obligation to Establish Market Rules that Will Not Have Ratepayers Paying Unjust or Unreasonable Prices

The CAISO has an obligation to ensure that prices on its system and in its markets are just and reasonable and that it cost-effectively manages congestion on the CAISO Controlled Grid.[75] As explained in the testimony of Dr. Harvey, the CAISO must buy power offered by CAISO sellers in a transparent market; there is no symmetric obligation on the SMUD-TID IBAA.[76] In other words, because the CAISO must accept all qualified offers to sell and buy into its markets, the CAISO has the right and responsibility to establish an appropriate price and terms for such sales and purchases.[77] In the absence of information regarding the location and operation of the external resources used to implement interchange transactions, the CAISO must establish market rules and related prices that eliminate inappropriate price incentives and reduce the risk to CAISO Market Participants of paying: (i) too much for power, and (ii) for the cost of the real time re-dispatch necessary because the CAISO procured and paid for power that was not representative of the value of such power to the CAISO for managing congestion on the CAISO Controlled Grid.[78]

c. In the Absence of Information, the Default Locations Are Reasonable Approximations of the Marginal Resources for Import and Export Transactions

Finally, in the absence of more detailed information, the default locations are reasonable approximations of the marginal, external resources likely to support imports to, and exports from the CAISO Controlled Grid.[79] On any given day, the CAISO believes that it is a reasonable assumption that entities within the SMUD and TID IBAA will procure generally less expensive power available from the Pacific Northwest.[80] Absent information that verifies that such entities are not dispatching their own internal generation to support a scheduled import to the CAISO, the CAISO believes that the Captain Jack System Resource represents a reasonable approximation of the marginal resources likely to be used to support the scheduled interchange transaction.[81] Similarly, the CAISO believes that exports to the SMUD-TID IBAA will generally be scheduled to serve load in the SMUD area (as represented by the SMUD hub), since

---

and Malin are separated by a 500 kV low-impedance transmission line with that is not usually congested. Therefore, the LMPs at each location should be the same or very similar). *Id*. *See also*, Attachment I, *MSC Opinion* at 6.

75 Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 60.

76 Exhibit ISO-3, Testimony of Dr. Harvey, at 23.

77 Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 60.

78 *Id*.

79 *Id*.

80 *Id*.

81 *Id*. at 60-61.

that is the location in the SMUD-TID IBAA with the greatest amount of load and any export would reduce higher cost generation within the SMUD-TID BAA.[82]

5. The SMUD BAA and the Turlock BAA have the Characteristics of an IBAA

There are several general factors or characteristics that the CAISO evaluates in considering the need to model an external BAA as an IBAA in the Full Network Model. As specified in the proposed Section 27.5.3.3, these factors include but are not limited to the following:

- The number of interconnection points with the CAISO Balancing Authority Area and the distance between them;
- Whether the transmission system(s) within the Balancing Authority Area run(s) in parallel to major parts of the CAISO Controlled Grid;
- The frequency and magnitude of unscheduled flows at the interconnection tie-points;
- The number of hours where the actual direction of flows in real time reversed from day-ahead scheduled directions;
- The availability of information to the CAISO for modeling accuracy; and
- The estimated improvement to the CAISO's power flow modeling and congestion management processes to be achieved through more accurate modeling of the Balancing Authority Area.

The SMUD BAA and the TID BAA have the relevant characteristics for modeling the combined systems as an IBAA.[83] The transmission networks within the SMUD BAA and the TID BAA are embedded within and/or run in parallel to major parts of the CAISO Controlled Grid and transactions with these BAAs have a more significant impact on the CAISO Controlled Grid than other BAAs.[84] Second, the SMUD BAA has ten (10) networked interconnections with the CAISO.[85] The TID BAA has two networked interconnections with the CAISO Controlled Grid.[86] The next closest number of interconnections that any other interconnected BAA has with the CAISO Controlled Grid is four and several BAAs have one interconnection.

Third, due to the embedded or parallel nature of the SMUD transmission system and the TID transmission system, the accuracy of the CAISO's power flow modeling for the CAISO

---

82 *Id*.

83 *See* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 30-43.

84 *Id*. at 33-35.

85 *Id*. at 32.

86 *Id*.

Controlled Grid depends to a greater degree upon modeling both systems.[87] Fourth, there are large and persistent discrepancies between scheduled flows and actual flows between the SMUD BAA and the CAISO Controlled Grid and between the TID BAA and the CAISO Controlled Grid.[88] In addition to the differences between scheduled and actual flows, the number of hours in which the flows actually reversed direction (in comparing day-ahead schedules to actual, real time flows) was 6369 hours from December 1, 2006 to November 30, 2007 for the SMUD/Western/MID system.[89] Fifth, these systems were once part of the CAISO BAA and therefore, the CAISO has more extensive data available to it to enable it to determine the reasonableness of the assumptions it makes regarding the location of resources in these BAAs and the IBAA proposal. Sixth, alternating current ("AC") power flow solutions are very sensitive to network modeling accuracy. In testing the Full Network Model used for MRTU, the AC solution was sensitive to the modeling of the SMUD-TID IBAA.[90] In addition, there are critical network constraints and/or contingencies close to the IBAA boundary and the CAISO Controlled Grid. The critical network constraints include constraints near Stockton, CA (*i.e.*, near MID and TID) and near the Tesla and Tracy substations where major transmission lines between Western and the CAISO system connect with one another.[91] All of the considerations described above, were factors in the CAISO's decision to model the SMUD BAA and the TID BAA as an IBAA.

6. The CAISO Is Not Discriminating Against the SMUD BAA and the TID BAA by Proposing to Treat These Areas on an Integrated Basis

In the stakeholder process, certain participants either argued that the CAISO was unduly discriminating against the SMUD and TID BAAs or questioned why integrated modeling and pricing was required for the SMUD and TID BAAs and not required for the interconnections and interchange transactions with other BAAs. There are number of reasons why the CAISO's IBAA proposal is not unduly discriminatory towards the SMUD and TID BAAs and why it is imperative that the IBAA proposal be applied to the SMUD and TID BAAs at the start of MRTU operations.

First, with regard to the CAISO's Balancing Authority responsibilities, the SMUD-TID IBAA proposal does not change the interconnections with or interface relationships between the SMUD BA, the TID BA and the CAISO. Entities can continue to use the existing Intertie Scheduling Points under the IBAA proposal.[92] Second, with regard to the CAISO's market responsibilities, the IBAA proposal treats all market participants that import from or export to the SMUD-TID IBAA similarly. The default pricing rules apply to all schedules submitted by a market participant at the Intertie Scheduling Points between the CAISO and the SMUD-TID

---

87 *Id*. at 38-40.

88 *Id*. at 36-37.

89 *Id*. at 37.

90 *Id*. at 38-39.

91 *Id*. at 23.

92 *Id*. at 57.

IBAA (excluding to those schedules from a pseudo-tie).[93] Third, as noted in the previous section there are no other BAAs with which the CAISO is interconnected that have the same physical characteristics and same significant impacts on the CAISO Controlled Grid.[94] Under these circumstances, a more integrated approach to modeling and pricing of interchange transactions between the SMUD and TID BAAs and the CAISO Controlled Grid is necessary and such treatment is not unduly discriminatory.

Mr. Rothleder and Dr. Price explain that while the parallel flows are significant in other parts of the grid as well, the characteristics in this location are unique and represent the most integrated portions.[95] At a most basic level, these BAAs have a total of twelve Intertie Scheduling Points, as opposed to four for LADWP which is the next area with the most. The simple fact that there are so many interties exasperates the potential for the price chasing described by Dr. Harvey and Dr. Hildebrandt. Mr. Rothleder and Dr. Price explain that in the case of LADWP (which has the second highest number of interconnections with four Intertie Scheduling Points and also experiences a high degree of parallel transmission that parallels with the CAISO Controlled Grid at two of its interties), the CAISO has more visibility in that system because of its need to model certain entitlements on that system which have become part of the CAISO Controlled Grid.[96]

Also, other BAAs, such as the Comision Federal de Electricidad ("CFE") and the Imperial Irrigation District ("IID") have much fewer interconnections and the parallel flows are more minimal.[97] In addition, in the case of CFE the CAISO has additional visibility into those flows and can see whether one intertie or another will be used because some of the resources in that BAA are configured to switch between BAAs.[98] CAISO recognizes that in the case of IID, the parallel flows are not insignificant.[99] However, the CAISO at present does not have access to sufficient data to predict any problems under MRTU, or identify a solution to that problem. IID has multiple interconnections to Arizona that add complexity to the development of an appropriate model of IID as an IBAA.[100]

The approach the CAISO chooses to use in modeling and pricing of interchange transactions depends upon the specific physical characteristics of the interconnections between the BAAs and the CAISO Controlled Grid. The CAISO's choice of the SMUD and TID BAAs

---

93 *Id*. at 14.

94 *Id*. at 28-43.

95 *Id*.

96 *Id*. at 42-43.

97 *Id*. at 40-42.

98 *Id*. at 41.

99 *Id*. at 41-42.

100 *Id*. Mr. Rothleder and Dr. Price indicate that without a thorough review of such flows, partial modeling of the internal IID transmission to account for parallel flows on the IID transmission between the CAISO controlled SCE and SDGE systems may actually result in less accurate flows. *Id*. at 41-42. Therefore, additional study and potential visibility is necessary before proposing an IBAA approach for IID. *Id*. at 42.

to model and price on an integrated basis is hardly arbitrary, capricious or unduly discriminatory; it is based on the unique characteristics of the SMUD and TID BAAs and the issues they raise as they relate to the impact on the CAISO Controlled Grid.

Dr. Harvey also notes that PJM consolidated its southeast and southwest interface pricing points in 2006 to address the kind of inefficient scheduling incentives that concern the CAISO with the SMUD-TID IBAA, but that it did not consolidate other interface pricing points. Comparing PJM's experience with the CAISO's proposal, Dr. Harvey states that PJM's actions:

> did not reflect discrimination, it merely reflected PJM's judgment was to the locations at which the inefficient scheduling incentives were a problem that needed to be addressed. The CAISO has made a similar judgment in proposing the pricing rules for the SMUD-TID IBAA. Like PJM, the CAISO may find a need to make changes over time to its interchange pricing rules, but this filing concerns the pricing policies that are known to be needed now, not the changes that may be identified as needed in the future.[101]

As set forth in proposed tariff § 27.5.3, the CAISO will consider modeling other BAAs as IBAAs if, over time, they have or begin to exhibit the characteristics mentioned above.[102] If the CAISO begins to consider whether to change an existing IBAA or whether to model and price another BAA as an IBAA, it will initiate a stakeholder process and obtain stakeholder input regarding the contemplated change in modeling.[103]

7. Open Loop or Radial Modeling of the Other BAAs (*i.e.*, not the IBAA) is Acceptable for the Start of MRTU Operations

For most of the BAAs with which the CAISO is interconnected, the Full Network Model incorporates the BAAs in an "open loop" (or radial) format that treats each Intertie Scheduling Point independently of the others and does not try to represent power flows in the external BAAs. To model interchange transactions in a radial manner means modeling injections at or near the Intertie Scheduling Point with the CAISO Controlled Grid. Such modeling can be appropriate when it accurately reflects the topology of the external network, the location of the resources within the external network, and the flow affects on the CAISO Controlled Grid. Such modeling is inappropriate when modeling injections at or near the Intertie Scheduling Point with the CAISO Controlled Grid does not accurately reflect the network topology, location of the resources within the external network, and the flow affects on the CAISO Controlled Grid.

---

101 Exhibit ISO-3, Testimony of Dr. Harvey, at 31.

102 *See* Proposed MRTU § 27.5.3. Of course, given the CAISO's long term goal to have an exchange of more detailed data, if an interconnected BAA voluntarily wanted to engage in a higher level of coordination and integration with the CAISO, the CAISO would agree to such an arrangement notwithstanding the fact that the interconnected BAA might not meet all the criteria in the tariff.

103 *See* Proposed MRTU Tariff § 27.5.3.2.

Dr. Harvey notes that the importance of developing an improved model of the congestion impacts of scheduled interchange is not equal at all locations and that radial modeling can be adequate for both reliability and market purposes in certain circumstances, *e.g.*, if the interchange schedules would have similar impacts on the relevant binding transmission constraints regardless of which tie line they are modeled as flowing over.[104] For the start of MRTU operations, the CAISO believes that radial modeling and pricing is satisfactory for determining the impact of flows internal to, and between, the other BAAs (*i.e.*, the BAAs with which the CAISO is interconnected besides the SMUD and TID BAAs).[105]

The CAISO will monitor closely whether other BAAs should be modeled and priced as an IBAA.[106] Again, as noted by Dr. Harvey, the importance of developing improved modeling may change over time and radial modeling and pricing may become inadequate if transmission congestion patterns change.[107]

8. The CAISO's IBAA Proposal Reflects the Degree of Coordination and Information Currently Obtainable with Other BAAs (including the SMUD and TID BAAs)

The CAISO recognizes that there are other means by which the CAISO could obtain accurate information about the resources dispatched in real time to implement interchange transactions between the CAISO and a BAA. For example, if the CAISO and a BAA had joint or coordinated dispatch agreement, the CAISO likely would know the source and location of the resources dispatched to implement interchange transactions. Similarly, if the CAISO and a BAA were to model each other's systems in a "closed loop" fashion, the CAISO likely would know the source and location of the resources dispatched to implement interchange transactions.

Using a closed loop model is similar to a coordinated dispatch agreement because it requires a high degree of coordination and information exchange between the CAISO and the interconnected BAA. With a closed loop model the CAISO would know the actual location and physical operating characteristics of the generation and load within the BAA. However, as noted previously, the IBAA (and other adjacent BAAs) have expressed adamant opposition to providing the CAISO with more data or to moving to a closed loop configuration at this time.[108] Consequently, the IBAA proposal reflects the degree of coordination and information currently obtainable with the IBAA.[109]

---

[104] Exhibit ISO-3, Testimony of Dr. Harvey at 29.

[105] *See*, *e.g.*, Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price at 45-46.

[106] *Id*. at 62-63.

[107] Exhibit ISO-3, Testimony of Dr. Harvey at 29.

[108] At the CAISO Board Meeting on May 21, 2008, for example, a representative of SMUD stated that the municipality would "never" provide day-ahead data to the CAISO.

[109] The MSC shares the CAISO desire for a greater degree of coordination and information exchange between the CAISO and the IBAA (as well as other BAAs). The MSC states that:

> [T]here is no optimal solution to modeling and pricing transactions between the CAISO and neighboring BAAs given the current WECC protocols for settling deviations between neighboring

The elements of the CAISO's single hub, default pricing point proposal pertain directly to the type and amount of information the CAISO will receive from IBAA Entities regarding interchange transactions at the start of MRTU. It is clear from a review of the IBAA stakeholder process that: (a) the CAISO wants more data regarding the location and dispatch of external resources used to implement interchange transactions; (b) the IBAA Entities do not want to provide the data; and (c) the CAISO doesn't want to guess about the location of the external resources used to implement interchange transactions, so in the absence of data that would allow it to verify the location and dispatch of the external resources used to implement interchange transactions, the CAISO must use an approximation or default pricing points.

The CAISO believes the IBAA Entities would agree to the first two points; regarding the third point, there is a difference of opinion regarding what approach should be used at the start of MRTU. For example, the following is from a November 14, 2007 letter from SMUD to the CAISO:

> We believe the scope of the proposed CAISO MRTU regime should only apply at the boundaries or the physical interconnection points of all ICAs [Interconnected Control Areas]. This approach is consistent with our understanding of the standard business practices of other neighboring balancing authorities/control area operators within the Western Electricity Coordinating Council (WECC).
>
> * * * *
>
> We believe as public entities, and based upon many years of experience in operating our respective systems, adequate regulatory safeguards are already in place between the CAISO and SMUD/Western and TID ICAs to allow our business activities to be transacted exclusively at our physical points of interconnection, similar to what already occurs between the ICAs within the WECC. *That negates the need for the CAISO to acquire additional data for modeling our internal operations*."[110]

In the Commission process on Seams Issues and in the six month IBAA stakeholder process conducted by the CAISO from November 14, 2007 (the date of the above-quoted letter)

> BAAs. A clearly superior solution would be to settle inter-tie level real-time deviations between neighboring BAAs at the real-time LMP at that inter-tie. All parties could then be confident that power is being delivered at the location at which it has been scheduled, and that parties responsible for deviations from that schedule would bear the full costs caused by those deviations. We hope that the neighboring IBAAs will provide the necessary information to the CAISO so that it can move toward this solution as soon as possible. More broadly, we urge western BAAs to negotiate seams agreements that allow this sort of imbalance pricing and seams management.

MSC Opinion at 8.

[110] November 14, 2007 Letter from James R. Shetler, Sacramento Municipal Utility District to Charles King Vice-President of Market Development and Program Development at the CAISO at 1, 2 respectively (emphasis added).

to May 8, 2008, the CAISO amended its proposal and scaled back the information it would request in response to the IBAA Entities concerns.[111] Nonetheless, in their May 8, 2008 proposal, the IBAA Entities proposed that the CAISO model interchange schedules at the boundary / Intertie Scheduling Points between the CAISO and the IBAA.[112]

The combined position of the IBAA Entities on the exchange of data and pricing is neither reasonable nor tenable. The IBAA Entities do not want to provide more detailed data *but* they also want prices calculated on the most favorable assumptions regarding the location of their generation in all circumstances. Dr. Harvey describes the desire of the IBAA Entities to have their transaction modeled at the Intertie Scheduling Points (*i.e.*, to have the injections modeled as if there were a resource within the IBAA at or near the Intertie Scheduling Point) as requiring the CAISO to pay a price calculated based on the "most favorable" assumptions to them regarding the location of the generation supporting imports from their Balancing Authority Area in all circumstances, regardless of whether or not the imports are actually supported by generation whose location warrants the higher price.[113] Similarly, Dr. Hildebrandt states that the counterproposal of the IBAA Entities:

> is specifically designed to ensure that Market Participants have the ability to schedule imports and exports at [Intertie Scheduling Points] where prices would be *most favorable* to them, without any requirements or consideration as to the actual source of the generation supporting these schedules. Thus, the IBAA counter proposal is specifically designed to permit scheduling practices that conflict with the fundamental concerns identified by the CAISO.[114]

In testifying that the CAISO's proposal is reasonable, Dr. Harvey notes the CAISO's long run desire to exchange detailed scheduling, generation, and load information with other BAAs in order to assess the impact on the CAISO Controlled Grid of interchange transactions (as well as the base flows within the IBAA) and states that the long run goal:

> . . . . can only be achieved with the cooperation of adjacent Balancing Authority Areas that have a similar interest in improving reliability and reducing costs. While the CAISO pricing proposal for the SMUD-TID IBAA does not reflect the

[111] For example, the CAISO originally wanted each IBAA to provide detailed information regarding the scheduling of physical resources within the IBAA, including both "base schedules" regarding how the IBAA would serve its internal load as well as imports/exports and wheel-through transactions to and on the CAISO system. *See* Attachment E at 12 (quoting the joint report by CAISO and Western). In response to concerns regarding the exchange of detailed data, the CAISO scaled back its approach. *Id.* The joint Seams Report filed with SMUD for the third quarter of 2007 indicates that SMUD and Western thought the CAISO's revised approach was preferable to the more data-intensive original proposal which they views as a non-starter, but also needed more information about the approach. *Id.* at 16.

[112] *See* Municipal Proposal at 11, 14. The proposal was from the SMUD BA, the TID BA, and the TANC members and can be found at http://www.caiso.com/1fc2/1fc2d9bcd910.pdf.

[113] Exhibit ISO-3, Testimony of Dr. Harvey, at 22-23.

[114] Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 20 (emphasis added).

> intended end state, it is an improvement over the current scheduling and pricing mechanism, is better than the alternative proposed by the IBAA parties, and is a step forward toward the intended end state that ought to be taken. Until the end state system is implemented, the CAISO must operate the transmission system based on the best information available to it, and the current CAISO proposal will enable it to do so. In the absence of better information, the CAISO will make reasonable assumptions or approximations regarding the location of the resources supporting interchange transactions between the SMUD and TID Balancing Authority Areas and the CAISO.[115]

The CAISO's single hub IBAA proposal is eminently reasonable; it is tailored appropriately to the information the CAISO will be able to obtain regarding interchange transactions using the SMUD-TID IBAA. While the CAISO can't require the SMUD and TID BAA to exchange more detailed information with the CAISO, the IBAA Entities also cannot complain that the CAISO has chosen default modeling and pricing points that protect CAISO ratepayers from unreasonable costs and will result in a more reliable grid. This is particularly true given that that mechanism the CAISO has chosen is successfully used by RTOs in the east to address the same interchange issues.

9. The IBAA Proposal and CRRs.

During the stakeholder process, stakeholders raised a number of issues regarding the impact of the IBAA proposal on the revenue streams and congestion hedging effectiveness of CRRs. Under the IBAA proposal the congestion charges that will be applied in the Integrated Forward Market ("IFM") for schedules to or from an IBAA will be determined by the pricing points adopted for the particular IBAA.[116] A potential financial inconsistency for the CRR Holder could arise if the CRR Source or CRR Sink of a CRR from or to the IBAA, respectively, does not match the IBAA pricing point that will be used for settling the corresponding IFM interchange transaction. In its posted papers and stakeholder discussions on this issue the CAISO has clearly stated its intention – and has proposed specific policies to this end – to conform the settlement of CRRs between the CAISO and an IBAA to match the settlement of the corresponding IFM Energy schedules by utilizing the same pricing points for both settlements. Thus, if an Market Participant holds a CRR whose CRR Source or CRR Sink is in the IBAA and has an IFM Energy Schedule that matches the CRR in terms of source, sink and MW, the CRR settlement will exactly offset the IFM Energy settlement for that hour.[117]

In anticipation of the importance of conforming CRR settlement with IFM Energy settlement in cases where both are affected by the implementation of an IBAA in the CAISO markets, and based on the status of the SMUD-TID IBAA proposal at the time of the first annual

---

115 Exhibit ISO-3, Testimony of Dr. Harvey, at 24-25.

116 *See Release 1 Implementation of IBAA Modeling & Pricing Options* at 8. The paper can be found at http://www.caiso.com/1cb4/1cb4e0984a670.pdf.

117 *Id*.

CRR release process conducted in 2007, the CAISO did incorporate the SMUD-TID network into the CRR FNM and did establish CRR Sources and CRR Sinks corresponding to the pricing points of the multiple hub approach, and CRRs were released on that basis. Had the multiple hub approach gone forward, the released CRRs would have been fully consistent with the settlement of IFM interchange transactions between the IBAA and the CAISO.[118] With the move to a single hub pricing approach, however, it becomes necessary to address the potential inconsistency described above; that is, the CAISO must apply its proposed provisions for conforming "previously-released CRRs" to the new IFM Energy settlement pricing points associated with the revised IBAA approach.

a. The Impact of an IBAA Change on the Settlement of Previously-Released CRRs

The term "previously-released CRRs" refers to those CRRs that were released based on a CRR Full Network Model that did not include the IBAA change in question and that will continue to be in effect – either as active financial instruments or as allocated CRRs eligible for renewal nomination in the Priority Nomination Process (PNP) – when the IBAA change is implemented in the CAISO spot markets.[119] The concern expressed by several stakeholders relates to the potential for an IBAA change to create a discrepancy between the source or sink location of a previously-released CRR and the new source or sink that is adopted as a pricing point based on incorporating the IBAA transmission and pricing provisions into the Full Network Model. In resolving this issue, the CAISO considered two possible approaches:

> Approach 1: Allow the holder of a previously-released CRR whose source or sink is affected by the IBAA change to make a one-time election either to: (a) modify the settlement of the CRR to be congruent with the revised IFM pricing points associated with the IBAA change, or (b) retain the original source or sink specification of the CRR.
>
> Approach 2: Modify all relevant CRR settlements to reflect the IBAA change, as in option (a) of the first approach, without allowing the CRR Holder to elect to retain the original source or sink specification of the CRR.[120]

Based on stakeholder feedback and further consideration, the CAISO incorporated Approach 1 into the instant proposal and filing, subject to the requirement that affected CRR

---

[118] Some stakeholders mistakenly believed and commented that the FNM used to release CRRs in 2007 did not reflect the CAISO's original multiple hub IBAA proposal. However, the CAISO in fact had included in the FNM the detailed model of the SMUD-TID network facilities and the pricing points for the multiple hub IBAA proposal. The model was made available to Market Participants through the CRR process in the July 2007, timeframe. On December 3, 2007, the CAISO completed its first annual CRR Allocation and on December 19, 2007, the CAISO completed its first annual CRR Auction, releasing the CRRs planned to be in effect in conjunction with the then-anticipated "go live" date for MRTU of April 1, 2008. On January 4, 2008, the CAISO settled the outcome of the first annual CRR Auction.

[119] *See* the April 18, 2008 "Draft Final CAISO Integrated Balancing Authority Area (IBAA) Proposal ("*April 18, 2008 Final IBAA Proposal*") at 16.

[120] *Id*.

Holders make their elections prior to the start of the CAISO's process to release any new CRRs that will be effective for the period when the IBAA change will be in effect.[121] Allowing the choice per Approach 1 will enable CRR Holders to maintain their intended hedge against potential congestion costs for purposes of serving load if that is their objective, while also allowing those CRR Holders that procured a CRR for purely financial purposes to keep their original financial instruments. The requirement regarding the timing of the one-time election will ensure that the previous-released CRRs can be accurately represented in the CRR FNM for purposes of the next relevant CRR release process.

The implementation of the single-hub approach described herein is a departure from the assumptions of the CRR FNM under which 2008 CRRs were released that have sources or sinks within the IBAA. Hence such CRRs fit the definition of "previously-released CRRs and the provisions described above will apply. Under the proposal, holders of affected CRRs will be eligible to make a one-time election, for each affected CRR they hold, either to retain the IBAA source and sink specification as originally awarded, or to reconfigure the affected CRR source or sink to match the revised pricing locations of the single-hub IBAA approach.[122] These provisions will apply to: (a) Seasonal CRRs, allocated or auctioned, that are in effect during the months of 2008 for which the MRTU markets are operating, (b) previously-allocated Seasonal CRRs that are not affective during actual MRTU market operation but are eligible for PNP nomination in the upcoming process for releasing 2009 CRRs, and (c) previously-released Long Term CRRs.[123]

b. The Impact of an IBAA Change on the Revenue Adequacy of Previously-Released CRRs

One consequence of modifying the sources or sinks of previously-released CRRs to reflect the modified IBAA pricing locations is that that the entire set of previously-released CRRs may no longer be simultaneously feasible. This could increase the risk of a shortfall in the CAISO's collection of the IFM congestion revenues used to settle with CRR Holders.[124]

Because the MRTU Tariff and Commission policy require that all CRRs be fully funded, any revenue shortfall that results from IBAA-related changes to CRR sources and sinks would have to be funded to prevent any direct adverse affect on the CRR Holders. The CAISO proposes to use the CRR Balancing Account – which has already been approved by the

---

121 *See* proposed MRTU Tariff § 36.14.2.

122 *April 18, 2008 Final IBAA Proposal* at 17.

123 *Id*.

124 The CAISO notes that a departure from simultaneous feasibility would not definitively "cause" a shortfall in the CAISO's collection of the IFM congestion revenues used to settle with CRR Holders. Under the revenue adequacy theorem for financial transmission rights, changes in the network that result in a violation of simultaneous feasibility of outstanding rights only means that full revenue adequacy is no longer guaranteed. The actual impact of a departure from revenue adequacy due to an IBAA change or any other change in network conditions will depend on numerous factors including actual network conditions and actual supply and demand at the time the IFM is run.

Commission as the means to ensure full funding of CRRs – to cover any IBAA-related shortfall that occurs in a given month.[125]

There are several reasons why the CAISO believes it is appropriate to use the CRR Balancing Account to manage this risk. First, because any given IBAA change will occur in a limited area of the grid, it can be expected to affect a relatively small share of the total released CRRs, and hence any impact on revenue adequacy should be small relative to the total volume of congestion revenues and CRR settlements.[126] Second, although any particular IBAA change will typically occur in a specific area of the grid, the benefits of the IBAA change in terms of improved accuracy of congestion management and pricing will benefit users of the entire CAISO BAA.[127] Third, it will not be possible to specifically assign any net CRR revenue shortfall at the end of each month to the IBAA change in any reliable, non-arbitrary manner.[128]

Under the proposed single-hub approach, holders of affected CRRs will have the opportunity to reconfigure their affected sources or sinks as discussed in the previous sub-section. As noted there, there are three categories of CRRs that meet the definition of "previously-released CRRs" and may therefore be reconfigured. Of these three categories, only (a) and (c) have the potential to create violations of simultaneous feasibility. Category (b), the CRRs released for Seasons 2 and 3 of 2008 during which the MRTU markets were not in production, may be reconfigured only for purposes of PNP nomination for 2009. These reconfigured CRRs will not create any increased risk of revenue inadequacy because CRRs nominated into the PNP are awarded subject to a further Simultaneous Feasibility Test (SFT). Since the single-hub approach will be modeled in the CRR FNM for releasing 2009 CRRs, any reconfigured CRRs that are nominated in the PNP will be awarded only if they satisfy simultaneously feasibility.

In cases where IBAA changes are implemented after some Seasonal and Long-Term CRRs have been released based on different Full Network Model assumptions, the CAISO will be able to test for any potential failure of simultaneous feasibility and, if it exists, to estimate its magnitude. The CAISO proposes to perform this assessment for information purposes in accordance with the procedure outlined in the February 20, 2008 Issue Paper entitled "Congestion Revenue Rights (CRRs) Associated with Integrated Balancing Authority Areas (IBAAs)".[129]

c. Coordination of New IBAA Changes with Release of CRRs

The need to reconfigure previously-released CRRs can obviously be minimized if the implementation of new IBAAs or changes to existing IBAAs can be coordinated with the annual CRR release process. In general, the CAISO expects that any IBAA changes will undergo extensive study and analysis before they are implemented in the FNM for use in the spot

125 *See* proposed MRTU Tariff § 36.14.3.

126 *April 18, 2008 Final IBAA Proposal* at 18.

127 *Id.*

128 *Id.*

129 The issue paper can be found at http://www.caiso.com/1f74/1f74d20558b20.pdf.

markets, and therefore it will be feasible to plan such changes in conjunction with the annual CRR cycle. Thus, whenever possible the CAISO intends to schedule new IBAA changes to take effect on January 1 of a new year (*i.e.*, in the Day-Ahead Market that is run on December 31), and to provide to market participants all the IBAA modeling and pricing details as part of the FNM information package that is made available for CRR purposes prior to the conduct of the annual CRR release process for that year. As a result, all CRRs released – including one-year Seasonal CRRs as well as Long Term CRRs – would be released using the same basic FNM that will be used in the Day-Ahead and Real-Time markets when those CRRs become effective.

In some instances there may be a need to implement an IBAA change mid-year because of a need for improved accuracy in the Day-Ahead and Real-Time Market congestion management processes. In such a case the CAISO would implement the IBAA change in the spot markets on a first-of-the-month Trading Day and incorporate the IBAA change into the FNM for the corresponding monthly CRR process. In such instances the CAISO will follow the proposed provisions described above for reconfiguring previously-released CRRs and for assessing any potential departures from simultaneous feasibility due to such reconfiguration.

10. Process for Development of Additional or Changes to Existing IBAAs

In response to stakeholder concerns, the CAISO is also proposing to include in the tariff a new section 27.5.3.2 providing a general description of the criteria and process to be used for the adoption and implementation of additional IBAAs in the future (or a modification to any then-existing IBAAs). The MSC has recognized the potential need to modify the IBAA configuration:

> Because the transmission network configuration between the California ISO and the SMUD/WAPA/MID/TID IBAA is likely to change, the CAISO should reserve the right to change the collection of proxy buses that comprise the import and export pricing points. We recommend a stakeholder process justifying the need to change the status quo and the describing the advantages of the proposed change, with the approval by the California ISO Board or in emergency situations the simply the approval the CAISO management with ex post review by the California ISO Board. Our key point is the CAISO must have the flexibility to adapt the import and export pricing points to changing conditions in the CAISO and IBAA BAAs if the CAISO's IBAA proposal is to achieve the two main goals described above.[130]

The proposed process requires the CAISO to undertake a collaborative and consultative process with the affected BAAs and CAISO stakeholders. Specifically, the CAISO is proposing to include in section 27.5.3.2 a requirement that the CAISO initiate a stakeholder process before any change to the existing number of IBAAs. As part of this process, the CAISO will engage in direct discussions with the affected BAA and seek to develop modeling specifications that most

---

130 MSC IBAA Opinion at 8.

accurately reflect the affected BAA.[131] The CAISO notes that the first clause of the proposed tariff provision regarding an exception to the stakeholder consultation process for "exigent" circumstances was not included in the tariff provisions posted for stakeholder review. However, the tariff provision but the provision is consistent with the approval the CAISO received from its Board of Governors.[132] The CAISO believes it is important to specify that under exigent circumstances we may have to bypass the proposed stakeholder process to prevent serious harm to the market. The provision also is consistent with the MSC's Opinion, which provides in part that:

> Because the transmission network configuration between the California ISO and the SMUD/WAPA/MID/TID IBAA is likely to change, the CAISO should reserve the right to change the collection of proxy buses that comprise the import and export pricing points. We recommend a stakeholder process justifying the need to change the status quo and the describing the advantages of the proposed change, with the approval by the California ISO Board *or in emergency situations the simply the approval the CAISO management with ex post review by the California ISO Board.* Our key point is the CAISO must have the flexibility to adapt the import and export pricing points to changing conditions in the CAISO and IBAA BAAs if the CAISO's IBAA proposal is to achieve the two main goals described above.[133]

In addition, the CAISO will be required to discuss with stakeholders the modeling and pricing of the new or changed IBAA and would also be required to seek CAISO Governing Board approval to the extent that implementation of the new or changed IBAA requires changes to the IBAA provisions already reflected in the CAISO Tariff and BPMs. Finally, the CAISO would be required to make a FERC filing to modify its tariff to actually add a new IBAA or change any of the elements regarding the existing IBAA reflected in its Tariff. The CAISO believes this consultative process with the appropriate CAISO Governing Board and Commission approvals provides market participants sufficient reassurance of the process should a new IBAAs be adopted or if an existing IBAA changes.

---

131 Proposed MRTU Tariff § 27.5.3 specifies: "Except under exigent circumstances, the CAISO must follow a consultative process with the applicable Balancing Authority and CAISO Market Participants pursuant to the process further defined in the Business Practice Manuals, to establish a new IBAA or enter into a new MEEA or modify an existing IBAA or MEEA. Changes to an existing IBAA may include changes to the modeling of the IBAA's network topology or to the specification of the default Resource IDs described in Section 27.5.3.4. Upon completion of this process and having determined it necessary to establish a new IBAA or enter into a new MEEA or modify an existing IBAA or MEEA, the CAISO will make any necessary filings with FERC to amend this CAISO Tariff and to submit for FERC acceptance any related MEEA as appropriate, at which time the CAISO shall also provide its supportive findings for the establishment of the new IBAA or execution of the new MEEA or modification to an existing IBAA or MEEA."

132 *See* Attachment J, May 13, 2008 Board Memo at p. 11; *see also* Attachment J, Board of Governor's Motion Approving the Integrated Balancing Authority Area proposal "*as detailed in the memorandum, and related attachments*." (emphasis added).

133 Attachment I, *MSC Opinion*, at 8.

B. The Integrated Balancing Authority Area Proposal Is Consistent With the Experience of the Eastern RTOs

The CAISO's intent to resolve potential adverse market and reliability outcomes with the IBAA proposal is entirely consistent with the experience of Eastern RTOs/ISOs. Mechanisms similar to the IBAA proposal have proven to be successful in addressing these issues in the east. Dr. Harvey has substantial experience with the use of proxy bus mechanisms by the eastern RTOs. He notes that all of the existing LMP-based pricing systems currently use proxy bus mechanisms for analyzing and pricing the congestion impacts of interchange schedules and that the mechanisms are analogous to the methods the CAISO proposes to use to model and price scheduled interchange with the SMUD-TID IBAA.[134]

With regard to the NYISO, there is no instance in which it uses more than one proxy bus to model and price scheduled interchange over the free flowing ties with a single BAA.[135] Dr. Harvey indicates that the same is true for ISO New England ("ISO-NE") in that it has no more than one proxy bus or pricing point for interchange transactions over the free flowing ties with an adjacent BAA.[136] Dr. Harvey describes the trend in PJM since 1998 as one that has reduced the number of proxy buses, first to no more than one proxy bus per BAA, and now PJM typically uses a single proxy bus to price scheduled interchange with many distinct BAA.[137]

---

[134] Exhibit ISO-3, Testimony of Dr. Harvey, at 24-25.

[135] *Id.* at 32. The NYISO defines a Proxy Generator Bus as follows: "A proxy bus located outside the NYCA that is selected by the ISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The ISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services available at the Interface." *See* § 1.35g of the NYISO OATT and § 2.149 of the NYISO Market Services Tariff.

[136] Exhibit ISO-3, Testimony of Dr. Harvey, at 24-25. The ISO-NE defines an external node as: "a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs." *See* ISO-NE Tariff § III.1.3 – Definitions. Section III.2.7(i) of the ISO-NE Tariff provides that: "External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and reconfigure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts."

[137] Exhibit ISO-3, Testimony of Dr. Harvey, at 24-25. PJM has used the following provision in its Operating Agreement and in its OATT to make changes to proxy bus rules and configurations: "For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding interface point between adjacent Control Areas and the PJM Region." *See* § 3.3.1(d) of the PJM Operating Agreement and PJM OATT; *see also*, the August 12, 2002 PJM Report to FERC on Interface Pricing Policy, at p.1 (http://www.pjm.com/markets/market-monitor/downloads/mmureports/200208-report-ferc1.pdf); and the February 28, 2003 PJM Report to FERC on Interface Pricing Policy, at p.1 (http://www.pjm.com/markets/market-monitor/downloads/mmureports/20030301-interface-pricing.pdf).

PJM's history with proxy bus mechanisms provides part of the foundation for Dr Harvey's opinion that if presented with different prices at alternative scheduling points within the SMUD-TID BAA, market participants will schedule transactions along a contract path external to the CAISO Controlled Grid to the scheduling point with the most favorable price. According to Dr. Harvey: "[t]his kind of behavior has been repeatedly observed and continues to be observed in other markets. There is no need to wait to see what happens in California."[138]

In comparing the CAISO's IBAA proposal to the experience of the eastern RTOs, Dr. Harvey concludes by stating that:

> The CAISO's decision not to establish a separate pricing point for each interconnection with the SMUD and TID Balancing Authority Areas is consistent with the current practices of PJM, NYISO and ISO-NE and with the trend over time in their pricing of scheduled interchange. Moreover, the establishment of a single pricing point (the SMUD-TID IBAA) to price transactions with the SMUD and TID Balancing Authority Areas is consistent with the approach PJM has applied since 2003 to pricing transactions scheduled with Balancing Authority Areas on its southern border.[139]

Finally, Dr. Harvey notes that there is precedent for the CAISO's decision to make the Captain Jack pricing point for imports and the SMUD Hub pricing point for exports "default" pricing locations and allow market participants that engage in interchange transactions from the SMUD-TID IBAA to have alternative pricing arrangements so long as the CAISO is provided with information regarding the location of the external resources and can verify that the resources were dispatched to implement the interchange transaction.[140]

C. The IBAA Proposal is a Just and Reasonable Means of Meeting the CAISO's Modeling and Pricing Objectives

As noted by Dr. Harvey, except for BAAs that are radially interconnected, no single proxy bus location will provide a perfect representation, under all conditions, of the changes in line flows associated with a change in scheduled net interchange with that dispatch region.[141] Dr. Harvey states that any single proxy bus pricing system is necessarily a compromise absent a high degree of information exchange between two BAAs regarding interchange transactions.[142] Specifically, Dr. Harvey explains that:

---

[138] *Id*. at 7.

[139] *Id*. at 38.

[140] *Id*. at 38-40.

[141] *See* Exhibit ISO-4, Scott Harvey, "Proxy Buses and Congestion Pricing of Inter-Balancing Authority Area Transactions" June 9, 2008 at 8.

[142] *Id*.

> in practice, except in the case of radially connected dispatch regions, no single proxy bus location will provide a perfect representation, under all conditions, of the changes in line flows associated with a change in scheduled net interchange with that balancing authority area. The location of the proxy bus in any single proxy bus pricing system is therefore necessarily a compromise that will not be ideal over all system conditions.[143]

The opinion of the CAISO's MSC is similar to that of Dr. Harvey's. The MSC states that in the absence of detailed information on the day-ahead schedules of all generation units and inter-ties outside of the CAISO control area that exert an influence on power flows in the CAISO BAA, the CAISO's "proposal of a single aggregate IBAA with an import and export price appears to be the best available way to obtain day-ahead schedules that are accurate predictions of real-time flows that do not involve significant monetary transfers from CAISO participants to these entities."[144]

D. The Adverse Effects of Not Approving the IBAA Proposal

If the CAISO were not able to model the effects on the CAISO Controlled Grid of interchange transactions with SMUD and TID BAA per its IBAA proposal and instead were required to model the schedules for imports or exports as sourcing or sinking at the various Intertie Scheduling Points based on contract path schedules (*i.e.*, assuming the resources used to support interchange transactions with the SMUD and TID BAA were located directly at or near each Intertie Scheduling Points with the CAISO Controlled Grid), this would lead to a number of adverse reliability and market impacts.[145]

First, as described earlier, if there are material price differences across the various Intertie Scheduling Points at which imports can be delivered, sellers will use contract path schedules to deliver the imports to the Intertie Scheduling Point with the highest price regardless of the actual location of the generation that will be increased to support that important. This fact is not troublesome *if* the location of the import and the modeled favorable impact on the CAISO Controlled Grid reflects the actual delivery of power. However, if this is not the case and the higher payments are premised on a modeled favorable impact on internal CAISO transmission constraints that will not exist in real-time, the CAISO ratepayer will pay an artificially high price to the external seller.[146] In addition, the CAISO will have to dispatch high cost internal generation to solve the transmission constraint in real-time, giving rise to congestion rent shortfalls and raising consumer costs without receiving any corresponding benefit.[147] This effect

---

[143] *Id*.

[144] *See* Attachment E to this filing, the MSC's Opinion on Modeling and Pricing of Integrated Balancing Areas under MRTU ("MSC Opinion") at 2.

[145] Exhibit ISO-3, Testimony of Dr. Harvey, at 18-20.

[146] *Id*. at 19.

[147] *Id*. *See also*, Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 9 (providing an example of how overpayment for imports can occur as well as the incurrence of additional re-dispatch costs in real time).

is referred to as "phantom congestion" by the Commission (*i.e.*, congestion modeled in the Day-Ahead Market that is not present in real-time).

Second, the modeling approach endorsed by the IBAA Entities would lead to adverse reliability impacts for CAISO consumers and the WECC because the CAISO would be required to anticipate congestion impacts in its day-ahead market model and hour-ahead ("HASP") analysis, that would be inconsistent with the transmission system flows and congestion impacts that would be present in real-time.[148] This effect is the reverse or the corollary to "phantom congestion." In other words, the modeling approach would mask congestion in the Day-Ahead Market that turns out to be present in real-time.[149]

Dr. Harvey notes that, in addition, the incorrect modeling of the impact of scheduled interchange would cause the CAISO forward models to include counterflows on binding constraints that would not be present in real-time operations. In this case, Dr. Harvey's opinion is that "[t]he CAISO could not reliably operate in such a manner and would be forced to make the kind of ad hoc adjustments it does today in order to anticipate real-time conditions, denying CAISO consumers one of the benefits of MRTU implementation."[150] According to Dr. Harvey, there would be adverse market impacts because "the ad hoc adjustments the CAISO would need to make in order to maintain reliability would lead to underutilization of the CAISO grid."[151]

In sum, if a proxy bus mechanism were not used and if the twelve interconnections with the SMUD-TID IBAA BAA were modeled in a radial manner, phantom congestion (and/or masking of congestion in the day-ahead market that would occur in Real Time) would still be a significant problem and it would: (i) force the CAISO's grid operators to scramble in real-time, (ii) add difficulty to maintaining the reliability of the CAISO system, and (iii) place the additional cost of dealing with such issues in real time on market participants.

E. Issues Raised In The Stakeholder Process By Entities Opposed To The IBAA Proposal

The most significant opposition to the IBAA proposal comes from the municipal entities in northern California, including the entities located within the SMUD and TID BAAs and certain participants in the COTP. The participants in the COTP are Pacific Gas & Electric Company ("PG&E"), Western, TANC, Carmichael Water District, the California City of Redding ("Redding"), the California City of Vernon ("Vernon"), and the San Juan Suburban Water District.[152] TANC and its members are the COTP participants that raise concerns

---

148 Exhibit ISO-3, Testimony of Dr. Harvey, at 19.

149 *Id*.

150 *Id*. at 19-20.

151 *Id*. at 20.

152 *See, e.g.*, the Owners Coordinated Operation Agreement ("OCOA") at § 4.16. The OCOA is on file at the Commission as PG&E Rate Schedule FERC No. 229. One of the TANC members - the City of Santa Clara, California doing business as Silicon Valley Power ("SVP") - is a load serving entity ("LSE") embedded in within CAISO Controlled Grid. Western also serves load within the footprint of the CAISO Controlled Grid.

regarding the IBAA proposal along with the other IBAA Entities. Each of their claims as reflected in the stakeholder comments are discussed in more detail below.

1. There Is Nothing Inappropriate About Using External Locations In The Full Network Model To Model The Effect Interchange Transactions On The CAISO Controlled Grid

The foundation for many of the arguments is the erroneous notion that placing System Resources in the Full Network Model at a location external to the CAISO Controlled Grid either is inappropriate or means that the CAISO will be asserting control or authority over non-CAISO Controlled Grid facilities.[153] The notion simply is incorrect.

The purpose of modeling and pricing interchange transactions between the CAISO and the IBAA is to avoid establishing improper scheduling and pricing incentives and to better assess the impacts of such transactions on the CAISO Controlled Grid. This is eminently reasonable. Interchange transactions with the CAISO require the use of the CAISO Controlled Grid. By their very nature, half of the resources used to implement interchange transactions are located externally to the CAISO Controlled Grid (*i.e.*, either the external generation increased to implement an import or the external generation decreased to implement an export). With free-flowing ties between the CAISO Controlled Grid and the IBAA, the flows generated from the use of the external resources will have impacts on the CAISO Controlled Grid and thereby affect LMPs on the CAISO Controlled Grid.

In the absence of better information that would confirm the location and operation of the external resources used to implement interchange transactions, placing individual or aggregated System Resources in the CAISO's Full Network Model at dominant transmission bus locations within the external IBAA (based on the best information the CAISO has) is a reasonable means of modeling the effects of such transactions on the CAISO Controlled Grid. It is not a perfect representation of the interchange transactions due to the absence of information exchanged with the CAISO. However, as explained by Dr. Harvey, Dr. Hildebrandt, and Mr. Rothleder and Dr. Price, in their respective testimony, in the absence of such information, the IBAA proposal is an improvement over what the IBAA Entities desire (*i.e.*, the modeling of fictional generation at each of the twelve Intertie Scheduling Points with the IBAA). Moreover, as discussed previously, the CAISO's approach to modeling and pricing interchange transactions is the same approach successfully being used by the RTO's in the east.

One of the complaints from the IBAA Entities is that the Tracy 500 interconnection point is in the SMUD BAA while the Captain Jack Substation is in a different BAA (*i.e.*, the

---

[153] *See, e.g.*, the March 6, 2008 Power Point Proposal of the Transmission Agency of Northern California: "Implications of the CAISO'sIBAA Proposal on the California-Oregon Transmission Project" at 6 ("The CAISO is unilaterally determining pricing nodes *within the IBAA, not at the interchange points* between the CAISO and IBAAs" (emphasis added)) (hereinafter: "March 6, 2008 TANC Power Point Presentation"). The *March 6, 2008 TANC Power Point Presentation* can be found at http://www.caiso.com/1f82/1f82854699b0.pdf.

Bonneville Power Administration's ("BPA") BAA).[154] There is nothing inappropriate about the fact that the external modeling location is in a location other than an adjacent BAA. For example, PJM uses a proxy bus in Ontario to model and price transactions with PJM even though the Ontario BAA is not adjacent to PJM.[155]

The argument that, in the absence of better information from the IBAA Entities, the CAISO may not place System Resources in the Full Network Model at external locations (based on the best information it has) in order to assess the impact of interchange transactions on the CAISO Controlled Grid is tantamount to saying the CAISO cannot use location-based marginal pricing for interchange transactions. At the very least, the allegation (if accepted) would mean that the CAISO must model interchange transactions as if the external resources used to implement the transactions are at or near the interconnection point even when the CAISO knows such an assumption about the external network is incorrect. This is an unreasonable position that would have CAISO ratepayers bearing unreasonable and unnecessary costs for the reasons discussed previously.

The recommendations of the IBAA Entities contain two basic points, the combination of which is unreasonable. First, they argue that the CAISO must use the most inaccurate form of modeling and pricing for interchange transactions with the IBAA (*i.e.*, radial modeling and pricing at multiple pricing points). Second, they are adamant about not providing the CAISO with information that would allow the CAISO to better reflect the impact of interchange transactions on the CAISO Controlled Grid (*i.e.*, information that would ensure consistency between the day-ahead scheduling of the external resources used to implement interchange transactions and the real time dispatch of those resources). In the absence of having more information about the external resources used to implement interchange transactions, the use of the single-hub approach is a necessary and reasonable default proposal that avoids the negative scheduling incentives associated with entities engaging in interchange transactions chasing prices where the scheduled delivery and flows do not accurately reflect actual delivery and flows.

2. The CAISO's Proposal Is A Substantial Improvement Over Radial Modeling At Each Of The Multiple Pricing Points With The IBAA

The IBAA Entities argue that the IBAA proposal is not as accurate as the CAISO's original multiple hub pricing proposal from a modeling perspective. For example, CMUA states that:

> Indeed, the pricing proposals appear to move away from efforts to more accurately model neighboring systems, toward aggregation of prices in broad hubs. This proposal moves away from efforts to better match power flows and

[154] *Id*. at 5 (last bullet) The Tracy interconnection point is close to the terminus of the COTP and is a location in the SMUD BAA where the municipal entities believe the external generation should be modeled and priced.

[155] *See* Exhibit ISO-4, Scott Harvey, "Proxy Buses and Congestion Pricing of Inter-Balancing Authority Area Transactions" June 9, 2008 at27.

> prices, and undercuts the very rationale that has been the foundation of the IBAA efforts from the beginning.[156]

As noted previously, from a modeling perspective a single hub approach can be less accurate than the CAISO's original multiple hub approach with accurate identification by Market Participants of the resources actually supporting their scheduled interchange transaction and use of this information to assign transactions to the appropriate hub for pricing and modeling purposes. A single hub approach will, however, provide a more accurate model than a multiple hub approach in which Market Participants are permitted to use contract path schedules to deliver power to the highest priced hub, without regard to the location of the generation supporting the transaction.[157] Furthermore, the CAISO IBAA proposal will function as a multiple hub approach, and realize the associated modeling benefits, to the extent that the relevant market participants enter into alternative pricing arrangements with the CAISO. The CAISO cannot ignore the potential pricing consequences of a multiple hub proposal absent confidence that it can accurately identify the location of resources supporting scheduled interchange with the IBAA.

It is not reasonable to divorce modeling from pricing. Indeed, Dr. Hildebrandt describes the type of information the CAISO would still need under a multiple hub approach to ensure that consumers do not pay unreasonable prices.[158] Dr. Hildebrandt recommended that under a multiple hub approach each Scheduling Coordinator ("SC") agree that any Resource ID issued to the SC for each sub-hub(s) reflect the actual source of generation that would be used to support any interchange schedule or bids submitted under the Resource ID.[159] Dr. Hildebrandt also recommended that the CAISO have the right to review requests by Scheduling Coordinators ("SCs") for Resource IDs associated with the sub-hubs and request additional information to verify that the SC actually owns or controls resources within the sub hub for which it was requesting a Resource ID.[160] Furthermore, Dr. Hildebrandt recommended that the CAISO be able to request additional information including, but not limited to, metered generation data for any generating resources within the applicable sub hub(s) and information on trades to and from other market participants with the SMUD and TID BAAs. Dr. Hildebrandt explains that in order to determine whether "circular" scheduling activity is occurring, the CAISO may need to review schedules submitted by market participants to the SMUD and TID BAs in order to distinguish between and separate chains of schedules or e-tags related to scheduled transactions not only between the CAISO and the SMUD and TID BAAs, but also between the various sub hubs the

---

156 CMUA May 20, 2008 letter to Yakout Mansour CEO of the CAISO at 1. This letter can be found at http://www.caiso.com/1fd0/1fd0c44d38da0.pdf.

157 As noted previously, Dr. Hildebrant states that the potential congestion management benefits of the sub hub approach depend *entirely* on having an accurate representation of the marginal System Resource (*e.g.*, SMUD Hub, Western Hub, Captain Jack, etc.) actually supporting the import and export schedule and bids submitted by Market Participants. Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 8.

158 Exhibit ISO-2, Testimony of Dr. Hildebrandt, at 11-13.

159 *Id*. at 12.

160 *Id*.

CAISO originally was proposing.[161] Finally, Dr. Hildebrandt recommended that the CAISO reserve the authority and establish the software capability to quickly switch to a "single hub" approach if the concerns with the multiple hub proposal materialized.[162]

In summary, the CAISO cannot ignore the pricing consequences of the multiple hub approach. In the absence of receiving the type of information described by Dr. Hildebrant, the single hub approach is reasonable choice. As noted by Dr. Harvey, no single proxy bus location will provide a perfect representation, under all conditions, of the changes in line flows associated with a change in scheduled net interchange with the dispatch region (*i.e.*, the IBAA).[163] Moreover, the single hub approach is still more accurate than the approach the IBAA Entities desire, *i.e.*, radial modeling of resources at or near each of the multiple pricing points between the CAISO and the IBAA.[164]

3. The CAISO's Proposal Provides an Opportunity for the IBAA Entities to be Treated More Favorably Than Under Existing Zonal Congestion Model

Dr. Harvey explains that the CAISO proposal provides an opportunity for the IBAA Entities to be treated *more favorably* regarding the pricing of interchange transactions than under the CAISO's existing zonal congestion management model.[165] Under the CAISO's zonal congestion model, imports having a favorable impact on internal CAISO transmission constraints (*i.e.*, imports whose scheduling would reduce the need for out-of-merit dispatch of internal generation to manage intra-zonal congestion) are not paid a premium for their favorable impact on these intra-zonal constraints, they are paid the zonal price.[166] Dr. Harvey explains that as opposed to having a "property right infringed," under the IBAA pricing proposal, the IBAA Entities will have the opportunity to be treated more favorably than they are today, so long as they provide the requisite information to demonstrate that their exports to the CAISO are supported by generation that has a favorable impact on internal CAISO transmission constraints.[167] Dr. Harvey goes on to point out that:

> [w]hat the SMUD-TID IBAA parties do not get under the CAISO proposal is the opportunity to be paid a premium for power that in fact does not have a favorable impact on internal CAISO transmission constraints. SMUD-TID IBAA parties do

---

161 *Id*. at 13.

162 *Id*.

163 *See* Exhibit ISO-4, Scott Harvey, "Proxy Buses and Congestion Pricing of Inter-Balancing Authority Area Transactions" June 9, 2008 at 8.

164 *See* Exhibit ISO-3, Testimony of Dr. Harvey at 24-25 (emphasis added). While the two default pricing points under the single hub proposal won't reflect accurate modeling in all circumstances, they will correct reflect the location of the external resources in a number of circumstances. In contrast, the approach favored by the municipal community (*i.e.*, radial modeling at multiple pricing points) would be inaccurate more often than the CAISO's single hub approach and it would not address pricing issues.

165 Exhibit ISO-3, Testimony of Dr. Harvey at 26.

166 *Id*.

167 *Id*.

> not have a property right entitling them to extract artificially high prices from CAISO rate payers in this manner and do not have the ability to do so in today's market structure. *The mere implementation of MRTU should not give them this ability*. If their transactions do not have an appropriately favorable impact on internal CAISO transmission constraints, they should not be receiving a premium for their transactions that is premised on such a favorable impact.[168]

The IBAA proposal with its default pricing locations appropriately guards against having CAISO ratepayers exposed to artificially high prices merely due to MRTU implementation and the use of LMPs. The CAISO's proposal also provides the opportunity for market participants to be paid a premium if their interchange transactions actually have a favorable impact on internal CAISO transmission constraints, and if they provide the requisite information to the CAISO.

4. Under The IBAA Proposal The CAISO Will Not Charge For Transmission Service Over, Or Manage Congestion On, Non-CAISO Controlled Grid Facilities

The IBAA Entities claim that under the IBAA proposal, the CAISO will charge for transmission service over non-CAISO Controlled Grid facilities and will manage congestion on non-CAISO Controlled Grid facilities.[169] These allegations simply are incorrect.[170]

Under the CAISO's proposal, the LMPs produced are applied only to service over CAISO Controlled Grid facilities (*i.e.*, imports to, exports from, and transactions internal to the CAISO Controlled Grid). Regardless of the external location of the System Resources used to model the affect of interchange transactions on the CAISO Controlled Grid, the purpose and affect of the use of such System Resources is *solely* with regard to service over *the CAISO Controlled Grid*. Their use has no affect whatsoever on the rates paid for, or the transmission service over, the non-CAISO Grid facilities of the IBAA. Nor does the use of external System Resources manage congestion on the non-CAISO Grid facilities of the IBAA. The resulting LMPs only are applied to billing determinants associated with service over CAISO Controlled Grid facilities.

The arguments of the IBAA Entities, in large part, focus on the use of the COTP.[171] Any participant in the COTP that uses its rights to the COTP to deliver energy to load outside of the

---

168 *Id.* at 26-27 (emphasis added).

169 *See*, *e.g.*, *March 6, 2008 TANC Power Point Presentation* at 5 (second bullet). The *March 6, 2008 TANC Power Point Presentation* can be found at http://www.caiso.com/1f82/1f82854699b0.pdf.

170 Exhibit ISO-3, Testimony of Dr. Harvey at 20-12; *see also* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price at 74-79.

171 The CAISO notes that a small portion of the COTP is considered part of the CAISO Controlled Grid. PG&E has rights to use 33MWs of service over the COTP and these rights have been turned over to the CAISO's control. Therefore, a small amount of rights to use the COTP are CAISO Controlled Grid facilities but this fact is not germane to the CAISO's responses to the arguments of the municipal entities regarding the roughly 1567MWs of COTP capacity that is not part of the CAISO Controlled Grid.

CAISO BAA is not charged by the CAISO. Such a transaction does not involve the CAISO Controlled Grid; the settlement of the transaction is between the transmission customer and the COTP participants.

The same is true for the transmission service over the COTP that is used to deliver an import to, or an export from, the CAISO Controlled Grid. If a transmission customer has secured the right to use the COTP, the customer can use those transmission service rights to: (a) deliver energy or ancillary services to the CAISO Controlled Grid (an import), or (b) receive energy or ancillary services from the CAISO Controlled Grid (an export). But in either case, the entity is not charged by the CAISO for the use of the COTP. The charges between the COTP transmission customer and the COTP owners occurs under either Western's Open Access Transmission Tariff ("OATT") or TANC's Transmission Tariff.[172] The CAISO charges apply only to the service over CAISO Controlled Grid facilities required to deliver the import to, or the export from, the CAISO Controlled Grid.

It is important to remember that since its inception, the CAISO has provided transmission service and managed congestion over CAISO Controlled Grid facilities (which include the Intertie Scheduling Points at points of interconnection between CAISO Controlled Grid facilities and non-CAISO Controlled Grid facilities). With implementation of MRTU, the methods by which the CAISO will manage congestion on the CAISO Controlled Grid will change, but the focus of the new market design continues to be the operation of, and service over, CAISO Controlled Grid facilities and only CAISO Controlled Grid facilities. Approval and implementation of the IBAA proposal cannot, and does not, expand the sphere of CAISO operations to non-CAISO Controlled Grid facilities.[173]

5. The IBAA Proposal Does Not "Devalue" Service Over Non-CAISO Controlled Grid Facilities

Closely related to the allegations discussed in the previous section, is the allegation that the CAISO's proposal "devalues" the service over non-CAISO Grid facilities including the COTP.[174] However, as noted in the previous section, the value of using, *e.g.*, the COTP to serve load within the IBAA is unaffected by the CAISO proposal.

---

172 Western's Open Access Transmission Tariff can be found at the following website: http://www.oatioasis.com/WAPA/WAPAdocs/WAPA-OATT.pdf. TANC's Transmission Tariff for service over the COTP can be found at: http://www.oatioasis.com/TANC/TANCdocs/TANC_OATT_July_13_07.pdf. Western's Tariff is on file with the FERC as an acceptable non-jurisdictional reciprocity tariff.

173 MRTU was developed to remedy problems in the existing CAISO market design, in particular a flawed congestion management approach. Neither MRTU nor the IBAA proposal is attempting to institute a new service or reflect a new authorization given to the CAISO; rather, they apply new methodologies to the services being applied today under the CAISO's existing authorizations.

174 *See* SVP May 20, 2008 letter to Yakout Mansour CEO of the CAISO at 1. This letter can be found at http://www.caiso.com/1fd0/1fd0c52344720.pdf. *See also March 6, 2008 TANC Power Point Presentation* at 6 (first bullet). The presentation can be found at http://www.caiso.com/1f82/1f82854699b0.pdf.

The same is true for an entity wishing to schedule an interchange transaction with the CAISO (including a COTP participant with load within the CAISO BAA). The entity (*i.e.*, either a COTP participant or a COTP transmission customer) can use its COTP rights to deliver the import to, or remove the export from, the CAISO Controlled Grid with no charge from the CAISO for service over the COTP. The value of the rights to service over the COTP is maintained.

The IBAA proposal also does not modify or violate the CAISO's treatment of Transmission Ownership Rights ("TORs")[175] or Existing transmission Contracts ("ETCs")[176] under MRTU.[177] The IBAA proposal does not modify the ability for an ETC or TOR rights holder to schedule a transaction at a specific Intertie Scheduling Point, if the ETC or TOR rights holders is entitled to do so under its ETC or TOR allows for use of that point.[178] In the event that an IBAA Hub is established that affects the price and related settlement of schedules at a specific Intertie Scheduling Point based on the hub pricing, the ETC and TOR "perfect hedge" settlement accepted as part of the CAISO's MRTU Tariff would be based on the congestion component of the LMP consistent with the IBAA hub pricing established for the specific Intertie Scheduling Point.[179]

6. Under the IBAA Proposal The CAISO Will Not Charge For Either Losses On Non-CAISO Controlled Grid Facilities Or For Losses Associated with Parallel Flows over CAISO Controlled Grid Facilities

The IBAA Entities claim that under the IBAA proposal, the CAISO will charge for losses on non-CAISO Controlled Grid facilities and for unscheduled flow over CAISO Controlled Grid facilities.[180] Neither of these claims is correct.

Regarding losses, the CAISO has indicated that while transmission losses within the IBAA will be accounted for in the power flow calculations, the marginal impact of these losses will be removed from the calculations for setting the LMPs used to price service on the CAISO Controlled Grid.[181] The reason for removing these losses in setting LMPs is because the CAISO

---

175 TORs are defined as "[t]he ownership or joint ownership right to transmission facilities within the CAISO Balancing Authority Area of a Non-Participating TO that has not executed the Transmission Control Agreement, which transmission facilities are not incorporated into the CAISO Controlled Grid." MRTU Tariff, Appendix A.

176 ETCs are defined as "contracts which grant transmission service rights in existence on the CAISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time." MRTU Tariff, Appendix A.

177 *See* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 74-81 (including a discussion of the COTP).

178 *Id*. at 80.

179 *Id*.

180 *See March 6, 2008 TANC Power Point Presentation* at 3 (third bullet) and 5 (third bullet); CMUA May 20, 2008 letter to Yakout Mansour CEO of the CAISO at 1.

181 *See* Exhibit ISO-1, Panel Testimony of Mark Rothleder and Dr. Price, at 67-68.

intends that the CAISO and each IBAA are responsible for the transmission losses within their own networks.[182] In addition, this intent or commitment of the CAISO is contained in the conditionally-approved MRTU Tariff. Per § 27.5.3 of the MRTU Tariff filed on February 9, 2006, the CAISO will model: "the resistive component for transmission losses on embedded Control Areas and adjacent Control Areas [IBAAs] but does not allow such losses to determine LMPs".[183] Therefore, the IBAA proposal will not double charge a COTP Participant or other participants within an IBAA for losses.

Regarding the allegation that the CAISO will charge for losses on unscheduled or parallel flows under MRTU, this also is not correct. The CAISO will charge for losses on *scheduled* flows on the CAISO Controlled Grid in the Day-Ahead Market and the Real Time Market under MRTU, it will not charge for *unscheduled* flows. There is, of course, a cost associated with the losses on parallel flows, *i.e.*, flows from *scheduled* transactions on *other transmission systems* that flow over the CAISO Controlled Grid[184] In order to maintain power balance and scheduled net interchange in real time, a BAA (including the CAISO) will generate more to make up for such losses. As a result, there is a real cost for additional generation to make up for such losses. However, in terms of the allegation of the IBAA Entities, the important point is that CAISO does not charge or collect money for losses from *schedules* that are not using the CAISO Controlled Grid even though there is a cost for losses incurred by the CAISO (due to the parallel flows associated with such schedules using non-CAISO Controlled Grid facilities). Currently each BA addresses this issue in its respective BAA.

Simply, the CAISO will not charge for transactions that do not explicitly use the CAISO Controlled Grid; the CAISO will also not be collecting for losses from such parallel flows external to the CAISO Controlled Grid. To the degree that the CAISO has to redispatch resources due to parallel flows on the CAISO Controlled Grid, CAISO demand will bear all these costs through neutrality in the Real-Time Market. This is the case under the CAISO's current market design and will also be the case under MRTU.

7. The IBAA Proposal Does Not Violate Existing Contractual Arrangements

As noted previously in Section IV.E.5 of this Transmittal Letter, the IBAA proposal does not violate ETCs, TORs, or the other agreements the CAISO has with other entities. However, the IBAA Entities have claimed that the IBAA proposal violates the Amended Owners Coordinated Operation Agreement ("OCOA") and the Amended California-Oregon Intertie Path Operating Agreement ("COI POA").[185] The CAISO is not a party to the OCOA but is a party to

---

[182] *Id*. The CAISO has explained that the contributions to the loss penalty factors from network branches within the each IBAA will be ignored by setting the contributions to zero.

[183] *See* MRTU Tariff § 27.5.3 (as filed on February 9, 2006).

[184] It is also true that scheduled transactions on the CAISO Controlled Grid also will have parallel flows on other, non-CAISO Controlled Grid facilities.

[185] *See* CMUA May 20, 2008 letter to Yakout Mansour CEO of the CAISO at 1; SVP May 20, 2008 letter to Yakout Mansour CEO of the CAISO at 1; and *March 6, 2008 TANC Power Point Presentation* at 3-6.

the COI POA. These agreements, among others, were recently amended per a Settlement Agreement approved in Docket No.ER07-882-000.[186]

The CAISO notes that in the more recent communications with TANC and the other IBAA Entities (including a May 8, 2008 offer from the IBAA Entities and the CAISO's response to that offer discussed in the next section), the statements regarding the OCOA have been that the IBAA violates "the spirit" of the OCOA as opposed to the actual provisions of the agreement. The CAISO is not sure if the IBAA Entities are no longer asserting that the IBAA proposal violates the provisions of the OCOA. Nonetheless, for the reasons set forth below, the CAISO does not believe the IBAA proposal violates either the spirit of the OCOA or its literal provisions.

a. The IBAA Proposal Does Not Violate The OCOA.

The Parties to the OCOA are PG&E, each COTP participant, and Western. The COTP is the 500-kV transmission line and associated facilities between the Captain Jack substation near the California-Oregon Border ("COB") and the COTP Terminus.[187] The COTP Terminus is defined as the point of interconnection between the PG&E Electric System and COTP, located at the eastern boundary of the existing right-of-way of the Tesla-Tracy 500 kV transmission line, at which the COTP's conductors extending from the Tracy Substation meet PG&E's conductors extending from PG&E's Tesla and Los Banos Substations.[188] The three-line "System" under the OCOA is defined as the combined facilities described as the PACI-P, PACI-W and the COTP.[189]

The fundamental allegation appears to be that because of the modeling and pricing aspects of the IBAA proposal, it violates existing contracts by creating charges for parallel flows.[190] First, as noted in the previous sections, the CAISO will not charge for unscheduled or parallel flows under the IBAA. Second, charging for transmission service over the CAISO Controlled Grid under the MRTU Tariff (and under the existing CAISO Tariff) does not violate the OCOA. Section 5 of the OCOA reads as follows:

---

186 The agreements are in Volume 2 of the Settlement Agreement and can be found using the FERC accession number 20071121-0124. The OCOA is Appendix 4 and the COI-POA is Appendix 5 to the Settlement Agreement in Docket No. ER07-882-000. In addition to using the FERC accession number, the documents can be found at http://elibrary.ferc.gov/idmws/Doc_Family.asp?document_id=13557072.

187 Section 4.8 of the OCOA.

188 Section 4.17 of the OCOA.

189 *See* § 4.48 of the OCOA. PACI stands for the "Pacific AC Intertie" and is defined as "that portion of the 500 kV AC Pacific Intertie located between COB and PG&E's Tesla Substation, associated 500 kV facilities at Tesla Substation and that portion of the Tesla-Tracy 500 kV AC transmission line between Tesla Substation and the COTP Terminus, including lines, substations and associated facilities." *See* § 4.33 of the OCOA. The term "PACI-P" means the portion of the PACI owned by PG&E and located between Indian Spring and the COTP Terminus and the portion of the PACI owned by PacifiCorp between Malin Substation and Indian Spring to which PG&E has rights. *See* § 4.34 of the OCOA. The term "PACI-P" means the portion of the PACI owned by PG&E and located between Indian Spring and the COTP Terminus and the portion of the PACI owned by PacifiCorp between Malin Substation and Indian Spring to which PG&E has rights. *See* § 4.35 of the OCOA.

190 *See, e.g.*, SVP May 20, 2008 letter to Yakout Mansour CEO of the CAISO at 1.

> <u>5 SCOPE OF AGREEMENT</u>
> This Agreement governs the coordinated operation of the PACI and COTP. It is the intent of the Parties to maintain the System as coordinated facilities to benefit its Transfer Capability. Except as to the use of the Tesla ByPass provided under this Agreement and as necessary to perform curtailment sharing obligations under Section 11 of this Agreement, no Party provides or shall be required to provide any transmission or other electric service to another Party *under this Agreement*.[191]

The section clearly provides that no Party shall provide (or be required to provide) transmission service or other electric service to another Party under the OCOA. The section does not prohibit a Party providing transmission service to another Party under other agreements, *e.g.*, Western's OATT, the TANC Transmission Tariff, PG&E's OATT (prior to the existence of the CAISO), the existing CAISO Tariff, or the MRTU Tariff when it goes into effect. A similar provision is contained in § 8.4 of the OCOA. The sentence reads as follows:

> Except to the extent necessary for sharing Curtailments, no Party shall have a right *under this Agreement* to have any of its power delivered on or otherwise have the use of transmission facilities owned by another Party.[192]

These sections provide that to the extent of each party's rights in the three-line system (with certain exceptions for curtailments and use of the Tesla ByPass), no Party shall be charged for another Party's use of the three-line system under the OCOA. The Parties recognize that the three line system is operated in a coordinated fashion and that there will be no charges under the OCOA for the physical flow affects of scheduling over the three line-system.[193] In other words, the flow affects of each Party's use of its rights in the three lines system on the transmission systems of the various owners are to be borne by the owners without charge under the OCOA.

There are two important observations to recognize from this brief review of the OCOA. First, when a Party to the OCOA requests transmission service from another Party under an agreement *other than* the OCOA, it must pay for and comply with the provisions of the Party's applicable transmission tariffs.[194] Second, whatever the flow affects are of each Party's use of its rights under the three-line system on the transmission systems of the various owners, those affects are to borne by the owners without charge under the OCOA. This basic set of

---

191 Section 5 of the OCOA (emphasis added).

192 Section 8.4 of the OCOA (emphasis added).

193 With the coordinated use of the three-line system, a portion of the affects of scheduling on the COTP will occur on the PACI-P and PACI-W facilities, and a portion of the affects of scheduling on, *e.g.*, PACI-P will occur on the PACI-W and COTP facilities.

194 It doesn't matter if the Party is using its full rights in the three-line system or not; if the Party requests service under another agreement or tariff other than the OCOA, it must comply with the rules of that tariff.

arrangements or principles have been in effect without violation since the start of the CAISO operations in 1998.

While MRTU and the IBAA proposal will change how congestion is managed on the CAISO Controlled Grid, neither will violate the OCOA when they go into effect. When a COTP participant requests transmission service from the CAISO, it will have to comply with MRTU Tariff and the CAISO will not charge the COTP participant for unscheduled flow on the CAISO Controlled Grid. Similarly, if PG&E (a Party to the OCOA) requests service under TANC's or Western's transmission tariff, it has to comply with the provisions of that tariff and it will not be charged for unscheduled flow under those tariffs.

b. The IBAA Proposal Does Not Violate The COI POA.

In contrast to the OCOA, the CAISO is a Party to the COI POA. The other Parties are are PG&E, the COTP participants, and Western. The CAISO's role under the agreement is as the Path Operator for the California-Oregon Intertie ("COI").[195] The IBAA proposal does not violate the CAISO's obligations under the COI POA.

There are twenty-one (21) duties of the Path Operator delineated in § 8.3 of the COI PAO. However, none of the duties is in conflict the MRTU Tariff or should prevent the CAISO from proceeding with the IBAA proposal.

The CAISO anticipates that TANC may mention § 8.3.19 of the COI POA. The CAISO does not believe it has not entered into an agreement with a COI Control Area Operator that has the attributes described in § 8.3.19 of the COI POA. The CAISO notes that it has entered into an agreement with SMUD entitled the California-Oregon Intertie Control Area Operating Agreement ("COI CAOA").[196] However, by its own terms, nothing in the COI CAOA would prohibit the CAISO from implementing the IBAA proposal.

F. Efforts of the CAISO and the IBAA Entities to Agree on an Alternative Arrangement Acceptable to Both Parties

Consistent with CAISO's IBAA proposal and the availability of alternative pricing arrangements (entitled "Market Efficiency Enhancement Agreements" or "MEEAs"), the CAISO has continued to negotiate with the IBAA Entities regarding an agreement that would address their issues in return for information that would enhance the efficiency of the MRTU markets for all market participants. The CAISO provides the Commission with the following summary of the negotiations between the IBAA Entities and the CAISO.

---

[195] *See* the COI POA at § 1 ("The CAISO is the Path Operator for COI"). The COI is defined as the "[t]he two 500-kV transmission lines between Malin Substation and Round Mountain Substation and the one 500-kV transmission line between Captain Jack Substation and Olinda Substation." *Id*. at § 4.9.

[196] The agreement is the Original Rate Schedule FERC No. 61 of the CAISO.

a. The Proposal of the IBAA Entities

On May 8, 2008, the IBAA Entities proposed an alternative arrangement that had three elements: (a) data exchange between the CAIIO and the IBAA Entities, (b) modeling of interchange transactions, and (c) pricing of interchange transactions ("IBAA Entities' Proposal").[197] Specifically, under the IBAA Entities' Proposal, the exchange of data would be on a reciprocal, after-the-fact basis. The Parties would provide WECC and NERC required real-time transmission data in each other's control for reliability purposes but the data subject to the agreement could not be physically removed from each other's site.[198] Under the IBAA Entities' Proposal, the CAISO would model interchange schedules at the boundary points or Intertie Scheduling Points between the CAISO and the IBAA.[199] With regarding to pricing, the interchange schedules/bids would be settled by calculating the LMPs at the boundary locations and applying the LMPs to the scheduled quantities (MW) at each ISP.[200]

b. The CAISO's Response

The CAISO responded to the IBAA Entities' Proposal on May 30, 2008. The CAISO indicated that it had concerns regarding the IBAA Entities' Proposal but that it provided a reasonable foundation for future discussions. The CAISO noted it was unclear how the additional data would enhance the CAISO's modeling of the IBAAs.[201] Second, the CAISO noted that under the IBAA Entities' Proposal, the CAISO would not have visibility regarding the location of the resources within the IBAA used to implement interchange transactions; rather, it appears as though each transaction would be modeled at the boundary (*i.e.*, assuming the resources are located at or near the ISPs themselves). While the IBAA Entity Proposal did provide that the CAISO would model the IBAA or external transmission system – and thus enable the CAISO to capture some of the network effects on its system by effectively distributing flows across the network associated with the scheduled interchange transactions – the source of such transactions would still be represented as injections at the ISPs at the boundary points. Without greater knowledge or visibility regarding the sources within the IBAA used to implement interchange transactions, the CAISO stated that it believed the prices produced at the identified Intertie Scheduling Points will not be representative of the value of the transactions scheduled at those locations for purposes of managing congestion on the CAISO Controlled Grid.[202] Third, the CAISO indicated it was not convinced the monitoring and

---

197 The proposal was from the SMUD BA, the TID BA, and the TANC members and can be found at http://www.caiso.com/1fc2/1fc2d9bcd910.pdf.

198 *See* the Municipal Proposal at 11, 12-13.

199 *Id*. at 11, 14.

200 Id. at 11, 16.

201 *Id.*

202 *Id.*

information exchange process would be sufficient to address the CAISO's previously articulated pricing concerns.[203]

Notwithstanding its concerns, the CAISO outlined the basis for a possible alternative arrangement or MEEA. The CAISO indicated that the concerns of the IBAA Entities were most pronounced with regard to the losses paid by an IBAA entity serving load within the CAISO BAA. The primary response of the CAISO's proposal is that the CAISO would exempt all qualifying COTP participants from CAISO losses associated with modeling an import from the SMUD and TID IBAA to the CAISO as an injection at the Captain Jack substation. Instead, the CAISO would charge a qualifying entity only for marginal losses from the Tracy 500 kV bus to their point of withdrawal/delivery on the CAISO Controlled Grid.

The exemption would only be available for COTP participants scheduling imports to serve load within the CAISO Balancing Authority Area. In addition, the treatment for losses should be limited in amount to: the megawatts of load served by the IBAA entity (and/or COTP Participant) internal to the CAISO BAA, minus any portion of the load served by an IBAA Entities' generation internal to the CAISO Balancing Authority Area and/or other purchases that do not use the COTP to deliver the purchased power to the CAISO Controlled Grid. Further, the exemption would not be available during any period in which the IBAA entity is simultaneously using COTP to import power to serve load with the CAISO Controlled Grid and scheduling exports from the CAISO transmission system, at Tracy or any other scheduling point.[204]

In return for providing such an exemption, the CAISO would receive additional data from the IBAA Entities that the CAISO could use to enhance its modeling, including enhanced modeling of losses. For example, the type of information that would provide the requisite market efficiency *quid pro quo* would be the provision, on a confidential basis, of all schedules on the COTP (not just schedules that support interchange transactions with the CAISO or not just schedules that use the CAISO grid). Such schedules would be submitted before 10AM of the day before the operating day for which those schedules are intended. In addition, the IBAA entities would authorize the CAISO to use such information in its Day Ahead and Real Time market processes for purposes of calculating congestion and losses on the CAISO transmission system.

Based on these, or equivalent provisions, the CAISO believes that its proposal is consistent with the stated purpose of a MEEA. The CAISO emphasizes it cannot enter into an arrangement that would forgive certain costs for certain market participants with there being a concomitant benefit for all market participants. The CAISO is continuing to work towards an

---

[203] *Id*. The CAISO also stated that it was not clear how the alternative proposal (with its boundary modeling and pricing of interchange transactions) would solve the alleged violation of the contract provisions claimed by municipal entities.

[204] The CAISO is considering whether an exemption from the rule on wheeling transactions is warranted for the New Melones pseudo-tie or possibly other situations issues.

alterative arrangement with the IBAA Entities and at the time of this filing has scheduled a follow-up meeting those entities.

V. CONTENTS OF FILING

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

Attachment A - Clean Currently Effective ISO Tariff sheets incorporating the black-lined changes contained in Attachment B

Attachment B - Black-lined changes to the Currently Effective ISO Tariff to implement the revisions discussed in this filing

Attachment C - Clean 4th Replacement CAISO Tariff (MRTU) sheets incorporating the black-lined changes contained in Attachment D

Attachment D - Black-lined changes to the 4th Replacement CAISO Tariff (MRTU) to implement the revisions discussed in this filing

Attachment E - Summary of the IBAA Development, Consultation, and Stakeholder Process

Attachment F - Exhibit No. ISO-1 – Panel Testimony of Mark Rothleder and Dr. James Price

Attachment G - Exhibit No. ISO-2 - Testimony of Dr. Eric Hildebrandt

Attachment H - Exhibit No. ISO-3 - Testimony of Dr. Scott Harvey; and
Exhibit No. ISO-4 - Paper by Dr. Scott Harvey, "Proxy Buses and Congestion Pricing of Inter-Balancing Authority Area Transactions" June 9, 2008

Attachment I - Opinion of the Market Surveillance Committee of the California Independent System Operator Corporation

Attachment J - CAISO Board Documents

VI. EFFECTIVE DATE, REQUEST FOR WAIVER OF 60-DAY NOTICE, AND NEED FOR EXPEDITED ACTION

The CAISO requests that the Commission approve the proposed changes to the MRTU Tariff to be effective upon implementation of MRTU. As noted in the CAISO's MRTU status reports filed in Docket No. ER06-615, the CAISO was required to delay the start of the Integrated Market Simulation – Update 2 ("IMS-U2") due to system stability issues, and the delay of IMS-U2 affected the previously proposed go-live date of April 1, 2008.

At this time, the CAISO is on track to implement MRTU in the fall 2008. The CAISO will not announce a new date until Market Participants have an opportunity to participate in scenario testing and provide feedback to CAISO management. The scheduled date for discussion of a new MRTU go-live date is the July 9-10, 2008 CAISO Governing Board meeting. Accordingly, the CAISO is filing clean MRTU Tariff sheets without indicating a proposed effective date and therefore requests waiver of Order No. 614[205] and applicable provisions of Section 35.9 of the Commission's regulations.[206]

In addition, the CAISO requests an effective date the CRR-related provisions *sixty days from the date of filing* so that CRR Holders of previously-released CRRs may have opportunity to elect to redefine their previously-released CRRs in anticipation of that the IBAA methodology will be in place during MRTU production. These sheets are contained in Attachment A.

The CAISO also respectfully requests that the Commission issue an order on the instant filing within 60 days or by August 12, 2008. Commission action on the IBAA proposal by that date is necessary in order to allow the proposed and Commission-approved functionality to be incorporated into the MRTU market systems and tested in time for the start of MRTU in the fall of 2008.

VII. COMMUNICATIONS

Correspondence and other communications regarding this filing should be directed to:

Nancy Saracino
Vice President, General Counsel
and Corporate Secretary
Anthony Ivancovich
Assistant General Counsel Regulatory
Anna McKenna*
Counsel
California Independent System Operator
Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7296
amckenna@caiso.com
* Individual designated for service.

Roger E. Smith*
David B. Rubin
Andrew Jamieson
Troutman Sanders LLP
401 9th Street, N.W., Suite 1000
Washington, D.C. 20004
(202) 274-2950
(202) 274-2994 (facsimile)
roger.smith@troutmansanders.com
david.rubin@troutmansanders.com

---

205 Designation of Electric Rate Schedule Sheets, FERC Stats. & Regs. ¶ 31,096 (2000).

206 18 C.F.R. § 35.9.

VIII. SERVICE

The CAISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all entities with effective Scheduling Coordinator Service Agreements under the current ISO Tariff. In addition, the CAISO is posting this transmittal letter and all attachments on the CAISO Website, and will provide courtesy copies of this filing to all parties in the MRTU proceeding (Docket No. ER06-615).

IX. CONCLUSION.

For the reasons expressed herein, the CAISO respectfully requests that the Commission accept the CAISO's filing as proposed and as discussed herein.

Respectfully submitted,

Anna McKenna
Nancy Saracino
Vice President, General Counsel
and Corporate Secretary
Anthony Ivancovich
Assistant General Counsel Regulatory
Anna McKenna
Counsel
California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7296
amckenna@caiso.com

Roger E. Smith
Roger E. Smith
David B. Rubin
Andrew Jamieson
TROUTMAN SANDERS LLP
401 9th Street, N.W., Suite 1000
Washington, D.C. 20004
(202) 274-2950
(202) 274-2994 (facsimile)
roger.smith@troutmansanders.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day electronically served a copy of the foregoing document on each party named in the official service list in this proceeding.

Dated at Folsom, CA this 17th day of June, 2008.

Anna McKenna

Anna McKenna

Attachment A – Clean Sheets

Integrated Balancing Authority Area Modeling and Pricing Amendment Filing

Currently Effective ISO Tariff

Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
IBAA	Integrated Balancing Authority Area
Integrated Balancing Authority Area (IBAA)	A Balancing Authority Area as provided in Section 27.5.3 of the MRTU Tariff that has been determined to have one or more direct interconnections with the CAISO Balancing Authority Area, such that power flows within the IBAA significantly affect power flows within the CAISO Balancing Authority Area, and whose network topology is therefore modeled in further detail in the CAISO's Full Network Model beyond the simple radial modeling of interconnections between the IBAA and the CAISO Balancing Authority Area.
Previously-Released CRRs	CRRs that were released based on a CRR FNM that did not include a particular IBAA change and that will continue to be in effect, either as active financial instruments or as allocated CRRs eligible for renewal nomination in the Priority Nomination Process, when the particular IBAA change is implemented in the CAISO Markets.

36.14 CRR Implications of Establishing New IBAAs or Modifying Existing IBAAs.

36.14.1 Coordination of IBAA Changes with Release of CRRs.

To the extent practicable, the CAISO will coordinate future IBAA changes, including establishment of new IBAAs and modifications to existing IBAAs, with the annual CRR Allocation and CRR Auction processes. Where feasible, the CAISO will implement the FNM containing the IBAA changes for use in the CAISO Markets beginning with the markets for a Trading Day of January 1 of a new calendar year and, consistent with Section 6.5.1 of the MRTU Tariff, will provide Market Participants all the IBAA modeling and pricing details as part of the FNM information package that is made available for CRR purposes prior to the CAISO conducting the annual CRR Allocation and CRR Auction process for that calendar year. As a result, all CRRs released in that process will be based upon the same FNM for IBAAs that will be used in the CAISO Markets when the released CRRs and the IBAA changes become effective. In the event that there is a need to implement an IBAA change other than on January 1, the CAISO will incorporate the IBAA change into the FNM for the monthly CRR Allocation and CRR Auction process for the first month in which the IBAA change will take effect. In all cases the CAISO will follow the provisions of this Section 36.14 for assessing and mitigating impacts on any Previously-Released CRRs.

36.14.2 Modifications to CRR Settlement of Previously-Released CRRs to Reflect IBAA Changes.

To the extent an IBAA change, including the establishment of a new IBAA or a change to an existing IBAA, modifies the pricing for Settlement purposes of IFM scheduled transactions between the CAISO Balancing Authority Area and the IBAA, the Settlement of certain Previously-Released CRRs may no longer be consistent with the modified IFM Settlement. A CRR Holder of a Previously-Released CRR whose CRR Source or CRR Sink is affected by an IBAA change may make a one-time election either to (a) modify the Settlement of the affected CRR Source or CRR Sink to conform to the revised IFM pricing associated with the IBAA change, or (b) retain the original CRR Source or CRR Sink specification of the Previously-Released CRR. The CRR Holder of such a CRR must make the one-time election prior to the first CRR Allocation and CRR Auction process that incorporates the IBAA change in the CRR FNM, in accordance with the process time line specified in the applicable Business Practice Manual. If the IBAA change is implemented to coincide with the beginning of a calendar year and is coordinated with the annual CRR Allocation and CRR Auction process for that year, as described in Section 36.14.1 of this Appendix, the provisions discussed herein apply only to Previously-Released CRRs that are Long Term CRRs and Previously-Released CRRs that are Seasonal CRRs obtained through the CRR Allocation and are eligible for PNP nomination. In the event that the IBAA change is implemented in the CAISO Markets other than on January 1, then these provisions apply also to any Previously-Released CRRs that are Seasonal CRRs effective for the remainder of the year in which the IBAA change is implemented.

36.14.3 Potential Impact of an IBAA Change on the Revenue Adequacy of Previously-Released CRRs.

It is possible that, as a result of modifying the CRR Sources or CRR Sinks of Previously-Released CRRs as provided in Section 36.14.2 of this Appendix, the entire set of Previously-Released CRRs may no longer be simultaneously feasible. Any such violation of simultaneous feasibility may or may not lead to a revenue shortfall, that is, a deficiency over the course of a month between the IFM Congestion Charge and the amount of funds needed to fully settle the CRRs that are in effect for that month. Consistent with Section 11.2.4.4.1 of the MRTU Tariff, any revenue shortfall that may result from IBAA-related changes to CRR Sources and CRR Sinks would be funded through the relevant monthly CRR Balancing Account.

Attachment B – Blacklines

Integrated Balancing Authority Area Modeling and Pricing Amendment Filing

Currently Effective ISO Tariff

* * *

ISO TARIFF APPENDIX BB

* * *

PART G. DEFINITIONS

* * *

Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

* * *

Balancing Authority Area	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

* * *

IBAA	Integrated Balancing Authority Area

* * *

Integrated Balancing Authority Area (IBAA)	A Balancing Authority Area as provided in Section 27.5.3 of the MRTU Tariff that has been determined to have one or more direct interconnections with the CAISO Balancing Authority Area, such that power flows within the IBAA significantly affect power flows within the CAISO Balancing Authority Area, and whose network topology is therefore modeled in further detail in the CAISO's Full Network Model beyond the simple radial modeling of interconnections between the IBAA and the CAISO Balancing Authority Area.

* * *

Previously-Released CRRs	CRRs that were released based on a CRR FNM that did not include a particular IBAA change and that will continue to be in effect, either as active financial instruments or as allocated CRRs eligible for renewal nomination in the Priority Nomination Process, when the particular IBAA change is implemented in the CAISO Markets.

* * *

PART H. CONGESTION REVENUE RIGHTS

* * *

36.14 CRR Implications of Establishing New IBAAs or Modifying Existing IBAAs.

36.14.1 Coordination of IBAA Changes with Release of CRRs.

To the extent practicable, the CAISO will coordinate future IBAA changes, including establishment of new IBAAs and modifications to existing IBAAs, with the annual CRR Allocation and CRR Auction processes. Where feasible, the CAISO will implement the FNM containing the IBAA changes for use in the CAISO Markets beginning with the markets for a Trading Day of January 1 of a new calendar year and, consistent with Section 6.5.1 of the MRTU Tariff, will provide Market Participants all the IBAA modeling and pricing details as part of the FNM information package that is made available for CRR purposes prior to the CAISO conducting the annual CRR Allocation and CRR Auction process for that calendar year. As a result, all CRRs released in that process will be based upon the same FNM for IBAAs that will be used in the CAISO Markets when the released CRRs and the IBAA changes become effective. In the event that there is a need to implement an IBAA change other than on January 1, the CAISO will incorporate the IBAA change into the FNM for the monthly CRR Allocation and CRR Auction process for the first month in which the IBAA change will take effect. In all cases the CAISO will follow the provisions of this Section 36.14 for assessing and mitigating impacts on any Previously-Released CRRs.

36.14.2 Modifications to CRR Settlement of Previously-Released CRRs to Reflect IBAA Changes.

To the extent an IBAA change, including the establishment of a new IBAA or a change to an existing IBAA, modifies the pricing for Settlement purposes of IFM scheduled transactions between the CAISO Balancing Authority Area and the IBAA, the Settlement of certain Previously-Released CRRs may no longer be consistent with the modified IFM Settlement. A CRR Holder of a Previously-Released CRR whose CRR Source or CRR Sink is affected by an IBAA change may make a one-time election either to (a) modify the Settlement of the affected CRR Source or CRR Sink to conform to the revised IFM pricing associated with the IBAA change, or (b) retain the original CRR Source or CRR Sink specification of the Previously-Released CRR. The CRR Holder of such a CRR must make the one-time election prior to the first CRR Allocation and CRR Auction process that incorporates the IBAA change in the CRR FNM, in accordance with the process time line specified in the applicable Business Practice Manual. If the IBAA change is implemented to coincide with the beginning of a calendar year and is coordinated with the annual CRR Allocation and CRR Auction process for that year, as described in Section 36.14.1 of this Appendix, the provisions discussed herein apply only to Previously-Released CRRs that are Long Term CRRs and Previously-Released CRRs that are Seasonal CRRs obtained through the CRR Allocation and are eligible for PNP nomination. In the event that the IBAA change is implemented in the CAISO Markets other than on January 1, then these provisions apply also to any Previously-Released CRRs that are Seasonal CRRs effective for the remainder of the year in which the IBAA change is implemented.

36.14.3 Potential Impact of an IBAA Change on the Revenue Adequacy of Previously-Released CRRs.

It is possible that, as a result of modifying the CRR Sources or CRR Sinks of Previously-Released CRRs as provided in Section 36.14.2 of this Appendix, the entire set of Previously-Released CRRs may no longer be simultaneously feasible. Any such violation of simultaneous feasibility may or may not lead to a revenue shortfall, that is, a deficiency over the course of a month between the IFM Congestion Charge and the amount of funds needed to fully settle the CRRs that are in effect for that month. Consistent with Section 11.2.4.4.1 of the MRTU Tariff, any revenue shortfall that may result from IBAA-related changes to CRR Sources and CRR Sinks would be funded through the relevant monthly CRR Balancing Account.

* * *

Attachment C – Clean Sheets

Integrated Balancing Authority Area Modeling and Pricing Amendment Filing

4th Replacement CAISO Tariff (MRTU)

CAISO's FNM. If overloads are observed in the forward markets, are internal to the MSS or at the MSS boundaries, and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the HASP and RTM to resolve the Congestion. The costs of such Exceptional Dispatch will be allocated to the responsible MSS Operator. Consistent with Section 4.9, the CAISO and MSS Operator shall develop specific procedures for each MSS to determine how network Constraints will be handled.

27.5.3 Integrated Balancing Authority Areas.

To the extent sufficient data is available or adequate estimates can be made for an IBAA, the FNM used by the CAISO for the CAISO Markets Processes will include a model of the IBAA's network topology. The CAISO monitors but does not enforce the network Constraints for an IBAA in running the CAISO Markets Processes, unless enforcement of such Constraints is allowed under a Market Efficiency Enhancement Agreement. Similarly, the CAISO models the resistive component for transmission losses on an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. As described in Section 27.5.3.4, for Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated System Resource injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

27.5.3.1 Currently Established Integrated Balancing Authority Areas.

The FNM includes the established IBAAs listed below. Additional details regarding the modeling specifications for these IBAAs are provided in the Business Practice Manuals.

(1) The Sacramento Municipal Utility District (SMUD) IBAA including the transmission facilities of the following entities:

(a) Western Area Power Administration – Sierra Nevada Region

(b) Modesto Irrigation District

(c) City of Redding

(d) City of Roseville

(2) Turlock Irrigation District IBAA

27.5.3.2 Process for Establishing a New Integrated Balancing Authority Area or Market Efficiency Enhancement Agreement or Modifying an Existing Integrated Balancing Authority Area or Market Efficiency Enhancement Agreement.

Except under exigent circumstances, the CAISO must follow a consultative process with the applicable Balancing Authority and CAISO Market Participants pursuant to the process further defined in the Business Practice Manuals, to establish a new IBAA or enter into a new MEEA or modify an existing IBAA or MEEA. Changes to an existing IBAA may include changes to the modeling of the IBAA's network topology or to the specification of the default Resource IDs described in Section 27.5.3.4. Upon completion of this process and having determined it necessary to establish a new IBAA or enter into a new MEEA or modify an existing IBAA or MEEA, the CAISO will make any necessary filings with FERC to amend this CAISO Tariff and to submit for FERC acceptance any related MEEA as appropriate, at which time the CAISO shall also provide its supportive findings for the establishment of the new IBAA or execution of the new MEEA or modification to an existing IBAA or MEEA.

27.5.3.3 Factors to Be Considered in Establishing a New Integrated Balancing Authority Area or Modifying an Existing Integrated Balancing Authority Area.

In establishing a new IBAA or modifying an existing IBAA, the factors that the CAISO will consider shall include, but are not limited to the following:

(1) The number of Interties between the IBAA and the CAISO Balancing Authority Area and the distance between them;

(2) Whether the transmission system(s) within the other Balancing Authority Area runs in parallel to major parts of the CAISO Controlled Grid;

(3) The frequency and magnitude of unscheduled power flows at applicable Interties;

(4) The number of hours where the actual direction of power flows was reversed from scheduled directions;

(5) The availability of information to the CAISO for modeling accuracy; and

(6) The estimated improvement to the CAISO's power flow modeling and Congestion Management processes to be achieved through more accurate modeling of the Balancing Authority Area.

27.5.3.4 Default Designation of External Resource Locations for Modeling Transactions Between the CAISO and an IBAA.

Prior to the establishment of a new IBAA or a change to an existing IBAA, the CAISO will define and publish default Resource IDs to be used for submitting import and export Bids and for settling import and export Schedules between the CAISO Balancing Authority Area and the IBAA. These default Resource IDs will specify in the Master File the default associations of Intertie Scheduling Point Bids and Schedules to supporting individual or aggregate System Resource injection or withdrawal locations in the FNM. The supporting injection and withdrawal locations will be determined by the CAISO to allow the impact of the associated Intertie Scheduling Point Bids and Schedules on the CAISO IBAA to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO. The CAISO's methodology for determining such default Resource IDs, as well as the specific default Resource IDs that have been adopted for the currently established IBAAs, are provided in the Business Practice Manuals. Alternative Resource IDs to be used instead of the default Resource IDs may be created and adopted for use in conjunction with Intertie Scheduling Point Bids and Schedules between the CAISO Balancing Authority Area and the IBAA based on a Market Efficiency Enhancement Agreement.

27.5.4 Accounting for Changes in Topology in FNM.

The CAISO will incorporate into the FNM information received pursuant to Section 24 for transmission expansion and Section 25 for generation interconnection to account for changes to the CAISO Controlled Grid and other facilities located within the CAISO Balancing Authority Area. This information will be incorporated into the network model data base in which the electrical network model is maintained for use by the State Estimator and which forms the basis for the FNM used by the CAISO Markets. The updated

36.14 CRR Implications of Establishing New IBAAs or Modifying Existing IBAAs.

36.14.1 Coordination of IBAA Changes with Release of CRRs.

To the extent practicable, the CAISO will coordinate future IBAA changes, including establishment of new IBAAs and modifications to existing IBAAs, with the annual CRR Allocation and CRR Auction processes. Where feasible, the CAISO will implement the FNM containing the IBAA changes for use in the CAISO Markets beginning with the markets for a Trading Day of January 1 of a new calendar year and, consistent with Section 6.5.1, will provide Market Participants all the IBAA modeling and pricing details as part of the FNM information package that is made available for CRR purposes prior to the CAISO conducting the annual CRR Allocation and CRR Auction process for that calendar year. As a result, all CRRs released in that process will be based upon the same FNM for IBAAs that will be used in the CAISO Markets when the released CRRs and the IBAA changes become effective. In the event that there is a need to implement an IBAA change other than on January 1, the CAISO will incorporate the IBAA change into the FNM for the monthly CRR Allocation and CRR Auction process for the first month in which the IBAA change will take effect. In all cases the CAISO will follow the provisions of this Section 36.14 for assessing and mitigating impacts on any Previously-Released CRRs.

36.14.2 Modifications to CRR Settlement of Previously-Released CRRs to Reflect IBAA Changes.

To the extent an IBAA change, including the establishment of a new IBAA or a change to an existing IBAA, modifies the pricing for Settlement purposes of IFM scheduled transactions between the CAISO Balancing Authority Area and the IBAA, the Settlement of certain Previously-Released CRRs may no longer be consistent with the modified IFM Settlement. A CRR Holder of a Previously-Released CRR whose CRR Source or CRR Sink is affected by an IBAA change may make a one-time election either to (a) modify the Settlement of the affected CRR Source or CRR Sink to conform to the revised IFM pricing associated with the IBAA change, or (b) retain the original CRR Source or CRR Sink specification of the Previously-Released CRR. The CRR Holder of such a CRR must make the one-time election prior to the first CRR Allocation and CRR Auction process that incorporates the IBAA change in the CRR FNM, in accordance with the process time line specified in the applicable Business Practice Manual. If the IBAA change is implemented to coincide with the beginning of a calendar year and is coordinated with the annual CRR Allocation and CRR Auction process for that year, as described in Section 36.14.1, the provisions discussed herein apply only to Previously-Released CRRs that are Long Term CRRs and Previously-Released CRRs that are Seasonal CRRs obtained through the CRR Allocation and are eligible for PNP nomination. In the event that the IBAA change is implemented in the CAISO Markets other than on January 1, then these provisions apply also to any Previously-Released CRRs that are Seasonal CRRs effective for the remainder of the year in which the IBAA change is implemented.

36.14.3 Potential Impact of an IBAA Change on the Revenue Adequacy of Previously-Released CRRs.

It is possible that, as a result of modifying the CRR Sources or CRR Sinks of Previously-Released CRRs as provided in Section 36.14.2, the entire set of Previously-Released CRRs may no longer be simultaneously feasible. Any such violation of simultaneous feasibility may or may not lead to a revenue shortfall, that is, a deficiency over the course of a month between the IFM Congestion Charge and the amount of funds needed to fully settle the CRRs that are in effect for that month. Consistent with Section 11.2.4.4.1, any revenue shortfall that may result from IBAA-related changes to CRR Sources and CRR Sinks would be funded through the relevant monthly CRR Balancing Account.

Appendix A

Master Definition Supplement

Access Charge	A charge paid by all Utility Distribution Companies, Small Utility Distribution Companies, and MSS Operators with Gross Load in a PTO Service Territory, as set forth in Article II. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge. The Access Charge will recover the Participating TO's Transmission Revenue Requirement in accordance with Appendix F, Schedule 3.
ACE	Area Control Error
ACR	All Constraints Run
Adjusted Load Metric	A Load Serving Entity's Load Metric minus the megawatts of Load served using Existing Transmission Contracts, Converted Rights, and Transmission Ownership Rights.
Adjusted RMR Invoice	The monthly invoice issued by the RMR Owner to the CAISO for adjustments made to the Revised Estimated RMR Invoice pursuant to the RMR Contract reflecting actual data for the billing month.
Adjusted Verified CRR Source Quantity	The MW amount eligible for nomination by an LSE or Qualified OBAALSE in a verified tier of the CRR Allocation process, determined by reducing a Verified CRR Source Quantity to account for circumstances where the ownership or contract right to a generating resource is effective only for a portion of a particular season or month for which CRRs are being nominated.

DSHBAOA	Dynamic Scheduling Host Balancing Authority Operating Agreement
Dynamic Resource-Specific System Resource	A Dynamic System Resource that is a specific generation resource outside the CAISO Balancing Authority Area.
Dynamic Schedule	A telemetered reading or value which is updated in Real-Time and which is used as an Interchange Schedule in the CAISO Energy Management System calculation of Area Control Error and the integrated value of which is treated as an Interchange Schedule for Interchange accounting purposes.
Dynamic Scheduling Host Balancing Authority Operating Agreement (DSHBAOA)	An agreement entered into between the CAISO and a Host Balancing Authority governing the terms of dynamic scheduling between the Host Balancing Authority and the CAISO in accordance with the Dynamic Scheduling Protocol set forth in Appendix X, a pro forma version of which agreement is set forth in Appendix B.9
Dynamic System Resource	A System Resource that has satisfied the CAISO's contractual and operational requirements for submitting a Dynamic Schedule, and for which a Dynamic Schedule has been submitted, including a Dynamic Resource-Specific System Resource.
E&P Agreement	Engineering & Procurement Agreement
Economic Bid	A Bid that includes quantity (MWh) and price ($) for specified Trading Hours.
Economic Planning Study	A study performed to provide a preliminary assessment of the potential cost effectiveness of mitigating specifically identified Congestion.
EEP	Electrical Emergency Plan
ELC Process	Extremely Long-Start Commitment Process
Electrical Emergency Plan (EEP)	A plan to be developed by the CAISO in consultation with Utility Distribution Companies to address situations when Energy reserve margins are forecast to be below established levels.

Electric Facility	An electric resource, including a Generating Unit, System Unit, or a Participating Load.
Eligible Capacity	Capacity of Generating Units, System Units, System Resources, or Participating Load that is not already under a contract to be a Resource Adequacy Resource, is not under an RMR Contract or is not currently designated as ICPM Capacity that effectively resolves a procurement shortfall or reliability concern and thus is eligible to be designated under the ICPM in accordance with Section 43.1.
Eligible Customer	(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.
Eligible Intermittent Resource	A Generating Unit that is powered solely by 1) wind, 2) solar energy, or 3) hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability.
ELS Resource	Extremely Long-Start Resource
Emissions Cost Demand	The level of Demand specified in Section 11.18.3.
Emissions Cost Invoice	The invoice submitted to the CAISO in accordance with Section 11.18.6.
Emissions Costs	The mitigation fees, excluding capital costs, assessed against a Generating Unit by a state or federal agency, including air quality districts, for exceeding applicable NOx emission limitations.
Emissions Eligible Generator	A Generator with a Generating Unit that is a BCR Eligible Resource.
EMS	Energy Management System

Hour-Ahead Scheduling Process (HASP)	The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the following activities: 1) accepts Bids for Supply of Energy, including imports, exports and Ancillary Services imports to be supplied during the next Trading Hour that apply to the MPM-RRD, RTUC, STUC, and RTD; 2) conducts the MPM-RRD on the Bids that apply to the RTUC, STUC, and RTD; and 3) conducts the RTUC for the hourly pre-dispatch of Energy and Ancillary Services.
Hourly Demand	The average of the instantaneous Demand integrated over a single clock hour, in MWh.
Hourly Real-Time LAP Price	The load deviation weighted average of the hourly average of the Dispatch Interval LMPs for the LAP in the relevant Trading Hour used for the settlement of UIE.
HVAC	High Voltage Access Charge
HVTRR	High Voltage Transmission Revenue Requirement
Hydro Spill Generation	Hydro-electric Generation in existence prior to the CAISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output; iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; or iv) has increased regulated water output to avoid an impending spill.
IBAA	Integrated Balancing Authority Area
IBAAOA	Interconnected Balancing Authority Area Operating Agreement
ICAOA	Interconnected Control Area Operating Agreement
ICPM	Interim Capacity Procurement Mechanism
ICPM Availability Factor	A factor as set forth in Appendix F, Schedule 6 that is used in calculating a resource's monthly ICPM Capacity Payment.

Independent Entity	The entity, not affiliated with the CAISO or any Market Participant, that assists the CAISO in the determination of reference prices.
Independent System Operator (ISO)	See California Independent System Operator Corporation.
Information System (OASIS)	CAISO maintains on the CAISO Website that allows all transmission customers to view the data simultaneously.
Initial Settlement Statement Reissue	The reissue of an Initial Settlement Statement T+38BD by the CAISO on the fifty-first (51st) Business Day from the relevant Trading Day (T+51BD) if T+51BD falls on a calendar day that is on or before the day the Invoice or Payment Advice for the bill period containing the relevant Trading Day is scheduled to publish.
Initial Settlement Statement T+38BD	A Settlement Statement generated by the CAISO for the calculation of Settlements for a given Trading Day, which is published on the thirty-eight Business Day from the relevant Trading Day (T+38BD) and is prior to the Invoice or Payment Advice published for the relevant bill period.
In-Service Date	The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Participating TO Interconnection Facilities to obtain back feed power.
Instructed Imbalance Energy (IIE)	The portion of Imbalance Energy resulting from Dispatch Instructions and HASP Intertie Schedules.
Integrated Balancing Authority Area (IBAA)	A Balancing Authority Area as provided in Section 27.5.3 that has been determined to have one or more direct interconnections with the CAISO Balancing Authority Area, such that power flows within the IBAA significantly affect power flows within the CAISO Balancing Authority Area, and whose network topology is therefore modeled in further detail in the CAISO's Full Network Model beyond the simple radial modeling of interconnections between the IBAA and the CAISO Balancing Authority Area.
Integrated Forward Market (IFM)	The pricing run conducted by the CAISO using SCUC in the Day-Ahead Market, after the MPM-RRD process, which includes Unit Commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply and Demand Bids.
Interchange	Imports and exports between the CAISO Balancing Authority Area and other Balancing Authority Areas.
Interchange Schedule	A final agreed-upon schedule of Energy to be transferred between the CAISO Control Balancing Authority Area and another Balancing Authority Area.

Manual RMR Dispatch	An RMR Dispatch Notice issued by the CAISO other than as a result of the MPM-RRD process.
Marginal Cost of Congestion (MCC)	The component of LMP at a PNode that accounts for the cost of congestion, as measured between that Node and a Reference Bus.
Marginal Cost of Losses (MCL)	The component of LMP at a PNode that accounts for the marginal real power losses, as measured between that Node and a Reference Bus.
Marginal Losses	The transmission system marginal real power losses that arise from changes in demand at a Node which are served by changes in generation at a Reference Bus.
Market Behavior Rules	Those rules established by FERC under Docket No. EL01-118.
Market Clearing	The act of conducting any of the process used by the CAISO to determine LMPs, Day-Ahead Schedules, RUC Awards or AS Awards, HASP Intertie Schedules and Dispatch Instructions based on Supply Bids and Demand Bids or CAISO Demand Forecast.
Market Clearing Price	The price in a market at which supply equals demand. All demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.
Market Close	The time after which the CAISO is no longer accepting Bids for its CAISO Markets which: 1) for the DAM is 10:00 A.M. Pacific Time of the Day-Ahead; and 2) for the HASP and the RTM is approximately seventy-five minutes prior to the Operating Hour.
Market Disruption	An action or event that causes a failure of the normal operation of any of the CAISO Markets.
Market Efficiency Enhancement Agreement (MEEA)	An agreement between the CAISO and the Balancing Authority of an IBAA, or any entity or group of entities that use the transmission system of an IBAA, which provides for an alternative modeling and pricing arrangement to the default IBAA modeling and pricing provisions provided in Section 27.5.3. The CAISO may enter into such an agreement provided that there is a demonstrable benefit to the CAISO Markets resulting from such alternative arrangements. Creation and modification of such an agreement will be pursuant to the process set forth in Section 27.5.3.2 and will be posted on the CAISO Website.

Market Interruption	The disruption of the normal operations of a CAISO Market.
Market Intervention	An action taken by the CAISO to override or augment the operation of a CAISO Market.
Market Manipulation	Has the meaning set forth in Section 37.7.
Market Monitoring Unit	The component of the CAISO organization (currently the "Department of Market Monitoring") that is assigned responsibility in the first instance for the functions of a Market Monitoring Unit, as that term is used in Docket No. EL01-118.

MCC	Marginal Cost of Congestion
MCL	Marginal Cost of Losses
MDT	Minimum Down Time
Measured Demand	The metered CAISO Demand plus Real-Time Interchange Export Schedules.
Medium Start Unit	A Generating Unit that requires between two and five hours to Start-Up and synchronize to the grid.
MEEA	Market Efficiency Enhancement Agreement
Merchant Transmission CRRs	Incremental CRRs that are created by the addition of a Merchant Transmission Facility. Merchant Transmission CRRs are effective for thirty (30) years or for the pre-specified intended life of the facility, whichever is less.
Merchant Transmission Facility	A transmission facility or upgrade that is part of the CAISO Controlled Grid and whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the CAISO's Access Charge or WAC or other regulatory cost recovery mechanism.
Meter Data	Energy usage data collected by a metering device or as may be otherwise derived by the use of Approved Load Profiles.
Meter Data Exchange Format	A format for submitting Meter Data to the CAISO which will be published by the CAISO on the CAISO Website or available on request.

Pre-RA Import Commitment	Any power purchase agreement, ownership interest, or other commercial arrangement entered into on or before March 10, 2006, by a Load Serving Entity serving Load in the CAISO Balancing Authority Area for the procurement of Energy or capacity from a resource or resources located outside the CAISO Balancing Authority Area. The Pre-RA Import Commitment shall be deemed to terminate upon the expiration of the initial term of the Pre-RA Import Commitment, notwithstanding any "evergreen" or other renewal provision exercisable at the option of the Load Serving Entity.
Pre-RA Import Commitment Capability	The quantity in MW assigned to a particular Intertie into the CAISO Balancing Authority Area based on a Pre-RA Import Commitment.
Previously-Released CRRs	CRRs that were released based on a CRR FNM that did not include a particular IBAA change and that will continue to be in effect, either as active financial instruments or as allocated CRRs eligible for renewal nomination in the Priority Nomination Process, when the particular IBAA change is implemented in the CAISO Markets.
Price Taker	A quantity only Energy Bid with no associated price.
Pricing Node (PNode)	A single network Node or subset of network Nodes where a physical injection or withdrawal is modeled and for which a Locational Marginal Price is calculated and used for financial settlements.
Primary CAISO Control Center	The CAISO Control Center located in Folsom, California.
Priority Nomination Process (PNP)	The step in an annual CRR Allocation in years beyond CRR Year One through which CRR Holders re-nominate (1) Seasonal CRRs they were allocated in the prior year, (2) Long Term CRRs that are expiring, and (3) Existing Transmission Contracts and Converted Rights that are expiring.
Priority Type	The Bid component that indicates if applicable the scheduling priority for the Settlement Period for Reliability Must-Run Generation, if applicable.
Prior Period Change	Any correction, surcharge, credit, refund or other adjustment pertaining to a billing month pursuant to an RMR Contract which is discovered after the Revised Adjusted RMR Invoice for such billing month has been issued.

Each LAP one includes only the buses of Market Participants who are in the LAP and who have Load that is represented by that LAP's definition. Market Participants that have metered Load must either be settled at a Default LAP or a Custom LAP created for each Load point of the Market Participant (nodal Settlement).

G. Intertie Scheduling Point Price Calculation

The CAISO calculates LMPs for Scheduling Points, which are represented in the FNM as PNodes or aggregations of PNodes, external to the CAISO Balancing Authority Area, through the same process that is used to calculate LMPs within the CAISO Balancing Authority Area. In some cases, facilities that are part of the CAISO Controlled Grid but are external to the CAISO Balancing Authority Area connect some Intertie Scheduling Points to the CAISO Balancing Authority Area, and in these cases the Scheduling Points are within external Balancing Authority Areas. In both of these cases, the Scheduling Points are represented in the FNM. The CAISO places injections and withdrawals at the Scheduling Point PNodes to represent Bids and Schedules whose supporting physical injection and withdrawal locations are unknown, and the LMPs for Settlement of accepted Bids are established at the Scheduling Point PNodes.

G.1 Intertie Scheduling Point Price Calculation for IBAAs

As described in Section 27.5.3, the CAISO's FNM includes a full model of the network topology of each IBAA. Consistent with the provisions of Section 27.5.3.4, the CAISO Tariff will specify Resource IDs that associate Intertie Scheduling Point Bids and Schedules with supporting injection and withdrawal locations on the FNM. As provided in Section 27.5.3.4, such Resource IDs may be specified by the CAISO based on the information available to it, or developed pursuant to a Market Efficiency Enhancement Agreement. Once these Resource IDs are established, the CAISO will determine Intertie Scheduling Point LMPs based on the injection and withdrawal locations associated with each Intertie Scheduling Point Bid and Schedule by the appropriate Resource ID. In calculating these LMPs the CAISO follows the provisions specified in Section 27.5.3 regarding the treatment of transmission Constraints and losses on the IBAA network facilities.

Attachment D – Blacklines

Integrated Balancing Authority Area Modeling and Pricing Amendment Filing

4th Replacement CAISO Tariff (MRTU)

* * *

27.5.3 ~~Embedded Control Areas and Adjacent Control Areas~~Integrated Balancing Authority Areas.

To the extent sufficient data is available or adequate estimates can be made for an IBAA~~the embedded Control Areas and adjacent Control Areas~~, the FNM ~~will include a full model of embedded Control Areas and adjacent Control Areas~~ used by the CAISO for ~~power flow calculations and congestion management in~~ the CAISO Markets Processes will include a model of the IBAA's network topology. The CAISO monitors but does not enforce the network ~~c~~Constraints for ~~embedded Control Areas or adjacent Control Areas~~an IBAA in running the CAISO Markets Processes, unless enforcement of such Constraints is allowed under a Market Efficiency Enhancement Agreement. Similarly, ~~T~~the CAISO models the resistive component for transmission losses on ~~embedded Control Areas and adjacent Control Areas~~an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. As described in Section 27.5.3.4, for Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated System Resource injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

27.5.3.1 Currently Established Integrated Balancing Authority Areas.

The FNM includes the established IBAAs listed below. Additional details regarding the modeling specifications for these IBAAs are provided in the Business Practice Manuals.

(1) The Sacramento Municipal Utility District (SMUD) IBAA including the transmission facilities of the following entities:

(a) Western Area Power Administration – Sierra Nevada Region

(b) Modesto Irrigation District

(c) City of Redding

(d) City of Roseville

(2) Turlock Irrigation District IBAA

27.5.3.2 Process for Establishing a New Integrated Balancing Authority Area or Market Efficiency Enhancement Agreement or Modifying an Existing Integrated Balancing Authority Area or Market Efficiency Enhancement Agreement.

Except under exigent circumstances, the CAISO must follow a consultative process with the applicable Balancing Authority and CAISO Market Participants pursuant to the process further defined in the Business Practice Manuals, to establish a new IBAA or enter into a new MEEA or modify an existing IBAA or MEEA. Changes to an existing IBAA may include changes to the modeling of the IBAA's network topology or to the specification of the default Resource IDs described in Section 27.5.3.4. Upon completion of this process and having determined it necessary to establish a new IBAA or enter into a new MEEA or modify an existing IBAA or MEEA, the CAISO will make any necessary filings with FERC to amend this CAISO Tariff and to submit for FERC acceptance any related MEEA as appropriate, at which time the CAISO shall also provide its supportive findings for the establishment of the new IBAA or execution of the new MEEA or modification to an existing IBAA or MEEA.

27.5.3.3 Factors to Be Considered in Establishing a New Integrated Balancing Authority Area or Modifying an Existing Integrated Balancing Authority Area.

In establishing a new IBAA or modifying an existing IBAA, the factors that the CAISO will consider shall include, but are not limited to the following:

(1) The number of Interties between the IBAA and the CAISO Balancing Authority Area and the distance between them;

(2) Whether the transmission system(s) within the other Balancing Authority Area runs in parallel to major parts of the CAISO Controlled Grid;

(3) The frequency and magnitude of unscheduled power flows at applicable Interties;

(4) The number of hours where the actual direction of power flows was reversed from scheduled directions;

(5) The availability of information to the CAISO for modeling accuracy; and

(6) The estimated improvement to the CAISO's power flow modeling and Congestion Management processes to be achieved through more accurate modeling of the Balancing Authority Area.

27.5.3.4 Default Designation of External Resource Locations for Modeling Transactions Between the CAISO and an IBAA.

Prior to the establishment of a new IBAA or a change to an existing IBAA, the CAISO will define and publish default Resource IDs to be used for submitting import and export Bids and for settling import and export Schedules between the CAISO Balancing Authority Area and the IBAA. These default Resource IDs will specify in the Master File the default associations of Intertie Scheduling Point Bids and Schedules to supporting individual or aggregate System Resource injection or withdrawal locations in the FNM. The supporting injection and withdrawal locations will be determined by the CAISO to allow the impact of the associated Intertie Scheduling Point Bids and Schedules on the CAISO IBAA to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO. The CAISO's methodology for determining such default Resource IDs, as well as the specific default Resource IDs that have been adopted for the currently established IBAAs, are provided in the Business Practice Manuals. Alternative Resource IDs to be used instead of the default Resource IDs may be created and adopted for use in conjunction with Intertie Scheduling Point Bids and Schedules between the CAISO Balancing Authority Area and the IBAA based on a Market Efficiency Enhancement Agreement.

* * *

36.14 CRR Implications of Establishing New IBAAs or Modifying Existing IBAAs.

36.14.1 Coordination of IBAA Changes with Release of CRRs.

To the extent practicable, the CAISO will coordinate future IBAA changes, including establishment of new IBAAs and modifications to existing IBAAs, with the annual CRR Allocation and CRR Auction processes. Where feasible, the CAISO will implement the FNM containing the IBAA changes for use in the CAISO Markets beginning with the markets for a Trading Day of January 1 of a new calendar year and, consistent with Section 6.5.1, will provide Market Participants all the IBAA modeling and pricing details as part of the FNM information package that is made available for CRR purposes prior to the CAISO conducting the annual CRR Allocation and CRR Auction process for that calendar year. As a result, all

CRRs released in that process will be based upon the same FNM for IBAAs that will be used in the CAISO Markets when the released CRRs and the IBAA changes become effective. In the event that there is a need to implement an IBAA change other than on January 1, the CAISO will incorporate the IBAA change into the FNM for the monthly CRR Allocation and CRR Auction process for the first month in which the IBAA change will take effect. In all cases the CAISO will follow the provisions of this Section 36.14 for assessing and mitigating impacts on any Previously-Released CRRs.

36.14.2 Modifications to CRR Settlement of Previously-Released CRRs to Reflect IBAA Changes.

To the extent an IBAA change, including the establishment of a new IBAA or a change to an existing IBAA, modifies the pricing for Settlement purposes of IFM scheduled transactions between the CAISO Balancing Authority Area and the IBAA, the Settlement of certain Previously-Released CRRs may no longer be consistent with the modified IFM Settlement. A CRR Holder of a Previously-Released CRR whose CRR Source or CRR Sink is affected by an IBAA change may make a one-time election either to (a) modify the Settlement of the affected CRR Source or CRR Sink to conform to the revised IFM pricing associated with the IBAA change, or (b) retain the original CRR Source or CRR Sink specification of the Previously-Released CRR. The CRR Holder of such a CRR must make the one-time election prior to the first CRR Allocation and CRR Auction process that incorporates the IBAA change in the CRR FNM, in accordance with the process time line specified in the applicable Business Practice Manual. If the IBAA change is implemented to coincide with the beginning of a calendar year and is coordinated with the annual CRR Allocation and CRR Auction process for that year, as described in Section 36.14.1, the provisions discussed herein apply only to Previously-Released CRRs that are Long Term CRRs and Previously-Released CRRs that are Seasonal CRRs obtained through the CRR Allocation and are eligible for PNP nomination. In the event that the IBAA change is implemented in the CAISO Markets other than on January 1, then these provisions apply also to any Previously-Released CRRs that are Seasonal CRRs effective for the remainder of the year in which the IBAA change is implemented.

36.14.3 Potential Impact of an IBAA Change on the Revenue Adequacy of Previously-Released CRRs.

It is possible that, as a result of modifying the CRR Sources or CRR Sinks of Previously-Released CRRs as provided in Section 36.14.2, the entire set of Previously-Released CRRs may no longer be simultaneously feasible. Any such violation of simultaneous feasibility may or may not lead to a revenue shortfall, that is, a deficiency over the course of a month between the IFM Congestion Charge and the amount of funds needed to fully settle the CRRs that are in effect for that month. Consistent with Section 11.2.4.4.1, any revenue shortfall that may result from IBAA-related changes to CRR Sources and CRR Sinks would be funded through the relevant monthly CRR Balancing Account.

* * *

CAISO Tariff Appendix A

Master Definitions Supplement

~~**ACA**~~	~~Adjacent Control Area~~

* * *

~~**Adjacent Control Area (ACA)**~~	~~A Control Area that is tightly interconnected with the CAISO Control Area, but also has direct interconnections with other Control Areas, possibly including other ACAs, such that power flows in one Control Area significantly affect power flows in the other Control Area.~~

* * *

~~**ECA**~~	~~Embedded Control Area~~

* * *

~~**Embedded Control Area (ECA)**~~	~~A Control Area that has direct interconnections exclusively with the CAISO Control Area, and no other Control Area.~~

* * *

IBAA	Integrated Balancing Authority Area

* * *

Integrated Balancing Authority Area (IBAA)	A Balancing Authority Area as provided in Section 27.5.3 that has been determined to have one or more direct interconnections with the CAISO Balancing Authority Area, such that power flows within the IBAA significantly affect power flows within the CAISO Balancing Authority Area, and whose network topology is therefore modeled in further detail in the CAISO's Full Network Model beyond the simple radial modeling of interconnections between the IBAA and the CAISO Balancing Authority Area.

* * *

Market Efficiency Enhancement Agreement (MEEA)	An agreement between the CAISO and the Balancing Authority of an IBAA, or any entity or group of entities that use the transmission system of an IBAA, which provides for an alternative modeling and pricing arrangement to the default IBAA modeling and pricing provisions provided in Section 27.5.3. The CAISO may enter into such an agreement provided that there is a demonstrable benefit to the CAISO Markets resulting from such alternative arrangements. Creation and modification of such an agreement will be pursuant to the process set forth in Section 27.5.3.2 and will be posted on the CAISO Website.

* * *

MEEA	Market Efficiency Enhancement Agreement

* * *

Previously-Released CRRs	CRRs that were released based on a CRR FNM that did not include a particular IBAA change and that will continue to be in effect, either as active financial instruments or as allocated CRRs eligible for renewal nomination in the Priority Nomination Process, when the particular IBAA change is implemented in the CAISO Markets.

* * *

CAISO Tariff Appendix C

Locational Marginal Price

* * *

G. Intertie Scheduling Point Price Calculation

The CAISO calculates LMPs for Scheduling Points, which are represented in the FNM as PNodes or ~~an~~ aggregations of PNodes, ~~that exist~~ external to the CAISO Balancing Authority Area, through the same process that is used to calculate LMPs within the CAISO Balancing Authority Area. ~~A Scheduling Point typically is physically located at an "outside" boundary of the CAISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the CAISO Controlled Grid).~~In some cases, facilities that are part of the CAISO Controlled Grid but are~~that is~~ external to the CAISO Balancing Authority Area connect~~s~~ some Intertie Scheduling Points to the CAISO Balancing Authority Area, and in these cases the

Scheduling Points are within external ~~Control~~Balancing Authority Areas. In both of these cases, the Scheduling Points are represented in the FNM. T~~t~~he CAISO places injections and withdrawals at the Scheduling Point~~s~~ PNodes to~~, which~~ represent Bids and Schedules whose supporting physical injection and withdrawal locations ~~is~~are unknown, and the LMPs for Settlement of accepted Bids ~~Interchange schedules~~ are established ~~by~~at the Scheduling Point PNodes.

G.1 Intertie Scheduling Point Price Calculation for IBAAs

As described in Section 27.5.3, t~~T~~he CAISO's FNM includes a full model of ~~Embedded Control Areas and Adjacent Control Areas~~ the network topology of each IBAA. Consistent with the provisions of Section 27.5.3.4, the CAISO Tariff will specify Resource IDs that associate Intertie Scheduling Point Bids and Schedules with supporting injection and withdrawal locations on the FNM. As provided in Section 27.5.3.4, such Resource IDs may be specified by the CAISO based on the information available to it, or developed pursuant to a Market Efficiency Enhancement Agreement. Once these Resource IDs are established, the CAISO will determine Intertie Scheduling Point LMPs based on the injection and withdrawal locations associated with each Intertie Scheduling Point Bid and Schedule by the appropriate Resource ID. In calculating these LMPs the CAISO follows the provisions specified in Section 27.5.3 regarding the treatment of transmission Constraints and losses on the IBAA network facilities.~~The CAISO may place injections and withdrawals within the Embedded Control Areas and Adjacent Control Areas, which represent Bids and Schedules for the Embedded Control Areas and Adjacent Control Areas impact on transmission flows, to ensure the accuracy of power flow calculations and Congestion Management within the CAISO Balancing Authority Area. The CAISO models the Congestion and losses in Embedded Control Areas and Adjacent Control Areas as described in Section 27.5.3. The CAISO will establish PNodes for the Embedded Control Areas' and Adjacent Control Areas' Scheduling Points through consultation with the Embedded Control Areas and Adjacent Control Areas. The CAISO will use Intertie scheduling Constraints to limit the quantity of scheduled Energy and AS on a specified Intertie. An Intertie Constraint is scheduled quantity limit as opposed to a flow based limit.~~

* * *

Attachment E

Summary of
IBAA Development, Consultation and Stakeholder Process

Summary of
IBAA Development, Consultation and Stakeholder Process

The CAISO has long acknowledged the need to appropriately model and price interchange transactions between the CAISO and neighboring Balancing Authority Areas. Beginning with the original MRTU design proposal (then referred to as the CAISO's Comprehensive Market Redesign 2002 or MD02 Proposal) in 2002, the CAISO acknowledged its intent to treat interchange transactions in a manner consistent with the CAISO's proposal Locational Marginal Pricing (LMP) methodology. While the CAISO's proposed approach, by necessity, has evolved over time, the CAISO has been clear that its long-term objective is to model interchange transactions in a manner that supports reliable and cost-effective congestion management on the CAISO Controlled Grid. This document provides a summary of the salient elements and key milestones of the CAISO's development, consultation, and stakeholder processes through which the CAISO has developed its proposed IBAA proposal.

I. EVOLUTION OF THE CAISO'S MARKET DESIGN PROPOSAL REGARDING MODELING OF INTERCHANGE TRANSACTIONS

The CAISO's Original MD02 Proposal

On May 1, 2002, the CAISO filed its Comprehensive Market Redesign Proposal (MD02). In that filing the CAISO outlined its intent to model and price interchange transactions using a detailed network representation of the larger Western electric system. Section 5.2.2.1 of the CAISO proposal stated as follows:

> **5.2.2.1 Congestion Management, Energy Market, Nodal Prices**
> The ISO is proposing a forward congestion management (CM) procedure that adjusts generation and load (and import and export) schedules to clear congestion using an optimal power flow algorithm (OPF) and a Full Network Model (FNM) that includes all busses and transmission constraints *as well as a network representation of the rest of the WSCC system to capture external loop flows*. [emphasis added]

The CAISO's intent was to accurately represent the impact of flows on external systems on the CAISO Controlled Grid for the purpose of managing congestion on the CAISO system. It is important to note that as of this date, May 2002, both SMUD and TID remained part of the CAISO Balancing Authority Area and had not yet elected to create their own Balancing Authority Areas.

The CAISO's Amended MD02 Proposal

On July 22, 2003, the CAISO amended its MD02 proposal to provide further detail on the then-proposed Phase 2 and Phase 3 of the MD02 proposal. Phase 2 and Phase 3 and addressed, among other things, the CAISO's revised proposal for an integrated forward energy market. Section 2.2.4 of that proposal stated as follows:

> **2.2.4 The Full Network Model**

> The ISO proposes eventually to utilize, in the forward markets and in Real Time, a full network model (FNM) that accurately represents constraints and interfaces of the ISO controlled grid and incorporates a model of the WECC regional grid external to the ISO control area. The external model will be a "closed-loop" model that represents external electrical connections between the various inter-ties into the ISO control area, and thus allows the ISO to explicitly estimate and manage parallel path or "loop" flows in coordination with other control areas in the region. Most significantly, the closed-loop FNM will accurately model loop flows due to internal resources and will result in accurate scheduling and dispatch of these resources to address congestion within the ISO-controlled grid.
>
> Implementation of a FNM that incorporates a "closed loop" approach is dependent on the availability and use of modeling data and forward energy schedules throughout the western interconnected region. The ISO will be prepared to implement this approach. However, explicit forward scheduling in a manner that accounts for loop flows may create severe problems if the ISO were to adopt this feature ahead of its neighbors throughout the west. Therefore, when Phase 3 is first implemented, the ISO may need to use a simpler "open loop" representation of the external network, until such time as there is an effective, coordinated western regional framework for Day Ahead scheduling and congestion management, including explicit scheduling of inter-control area parallel path flows.

As stated at that time, the CAISO acknowledged that implementation of a "closed loop" system, including a model of the WECC regional grid, was dependent on the *availability* and *use* of the necessary data, including forward energy schedules, from Balancing Authority Areas throughout the region. The CAISO also acknowledged that such a comprehensive approach may not be achievable absent regional agreement and therefore that the CAISO may have to use a simpler "open loop" representation of the external network at the start of the new market design. Once again, it is important to note that both SMUD and TID remained part of the CAISO Balancing Authority Area and had not yet elected to create their own Balancing Authority Areas.

The CAISO's MRTU Tariff Filing

On February 9, 2006, the CAISO filed the Market Redesign and Technology Upgrade (MRTU) Tariff. The MRTU filing reflected the CAISO's latest thinking regarding the modeling and treatment of interchange transactions. It is critical to note here that the CAISO's February 9, 2006, MRTU filing was the first filing made by the CAISO regarding interchange pricing after both SMUD and TID created their own Balancing Authority Areas. Page 14 of the CAISO's transmittal letter acknowledged this fact and explained the CAISO's evolved thinking regarding the Full Network Model. The transmittal letter stated as follows:

> **A. Full Network Model**
> As set forth in Section 27.5 of the MRTU Tariff, the CAISO markets under MRTU will employ a Full Network Model with an accurate

> representation of the CAISO Control Area *and all Control Areas that are either embedded within the CAISO Control Area or adjacent to the CAISO Control Area within the state of California*. Interconnections with all other adjacent Control Areas will be modeled in the FNM as radial lines. External Control Areas, except for transmission facilities for which Participating Transmission Owners have converted their scheduling rights, are not modeled. The FNM is composed of network nodes interconnected with network branches. Generation and Load Resources are modeled at the relevant network nodes. The use of the FNM in the DAM and the RTM incorporates Transmission Losses and allows the model to enforce all network constraints. This results in Locational Marginal Prices for Energy that reflect the marginal cost of Energy, losses, and Congestion. The MRTU power flow model will produce LMPs at every node in the network. The Full Network Model is also consistent with a point-to-point approach to scheduling and Congestion Management proposed in the MRTU Tariff. In contrast, the historic "contract path" paradigm, even though it has long been an industry practice in the Western Interconnection, is inconsistent with the physics of power flows. [emphasis added]

In addition, Footnote 15 of the transmittal letter stated as follows:

> A software change order recently provided to the CAISO's vendor will ensure that the FNM will include embedded and adjacent Control Areas that are predominately within California to the extent the CAISO has sufficient data to do so. The CAISO recognizes that detailed stakeholder discussion and review will be needed to resolve technical issues and data issues associated with the modeling of such adjacent and embedded Control Areas.

CAISO witness Kristov further elaborated that:

> The FNM is a detailed mathematical representation of the physical transmission system that the CAISO operates, and as its name suggests it accurately represents the constraints and interfaces of the CAISO Controlled Grid. It also incorporates a representation of other control areas within California that are not part of the CAISO Controlled Grid, as well as the interconnections between the CAISO and control areas in neighboring states. Initially the FNM will represent control areas in neighboring states in an "open loop" format that treats each intertie independently of the others and does not try to represent power flows in these external areas. Eventually, however, the open loop model will be replaced with a "closed loop" representation that captures external electrical connections between the various interties into the CAISO Control Area. This will allow the CAISO to estimate and manage parallel

> path or "loop" flows in coordination with other control areas in the western region, in a manner that is more accurate than is possible today.

(Exhibit No.ISO-1 at p. 17, lines 12-23, p. 18, lines 1-2).

As filed on February 9, 2006, section 27.5.3 of the MRTU Tariff read as follows:

> **27.5.3 Embedded Control Areas and Adjacent Control Areas.** To the extent sufficient data is available or adequate estimates can be made for the embedded Control Areas and adjacent Control Areas, the Full Network Model will include a full model of embedded Control Areas and adjacent Control Areas used for power flow calculations and congestion management in the CAISO Markets Processes. The CAISO monitors but does not enforce the network constraints for embedded Control Areas or adjacent Control Areas in running the CAISO Markets Processes. The CAISO models the resistive component for transmission losses on embedded Control Areas and adjacent Control Areas but does not allow such losses to determine LMPs.[1]

Furthermore, the CAISO identified the need to model embedded and adjacent control areas (now IBAAs) as a "must have" requirement. In testimony regarding the CAISO's "must have" requirements, CAISO witness Brian Rahman testified that a requirement was considered "must have" if (1) its functionality was necessary to resolve a critical defect in MRTU's mechanisms for ensuring reliability; (2) its functionality was necessary to resolve a critical defect in the markets established in MRTU; or (3) Market Participants had insisted on the inclusion of the component and the CAISO agreed to include the component (Rahman testimony at p. 6, lines 6-11). Mr. Rahman testified that the CAISO identified eleven areas in which the software needed to be modified in Release 1 of MRTU. The third item identified by Mr. Rahman was "Incorporation of capability to model adjacent and embedded Control Areas properly in order to prevent infeasible Integrated Forward Market ("IFM") solutions because of inaccurate modeling." (Rahman testimony at p. 6, lines 12-22).

Subsequent to the CAISO's MRTU Tariff filing, and consistent with the representations and process outlined in that filing, on July 31, 2006, the CAISO published a draft Business Practice Manual (BPM) for the Full Network Model indicating that the SMUD, Western, MID, and TID are Adjacent Control Areas that may be included in the FNM because they have transmission facilities that operate in parallel with the CAISO Control Area and are highly interconnected to the CAISO Control Area. *See* § 2.2.5 of July 31, 2006 BPM for the Full Network Model. The BPM can be found at (http://www.caiso.com/1841/1841c80437f00.pdf).

In its September 21, 2006 order on the MRTU Tariff (*September 2006 Order*), the Commission conditionally-approved Section 27.5 of the MRTU Tariff dealing with the

---

1 *See* MRTU Tariff § 27.5.3 (as filed on February 9, 2006).

Full Network Model and noted the CAISO's description of the Full Network Model as providing "an accurate representation of the CAISO Control Area and all control areas that are either embedded within the CAISO Control Area or adjacent to the CAISO Control Area [*i.e.*, IBAAs] and within the State of California."[2]

In the *September 2006 Order*, the Commission supported the CAISO's commitment to include more information concerning adjacent and embedded control areas (now IBAAs) in the Full Network Model as soon as possible.[3] The Commission agreed that the CAISO should operate the California grid using the most accurate model of internal and external areas that can be developed.[4] In addition, the Commission directed the CAISO to work with external control areas to develop the model more fully in the future, but noted that the CAISO can only model external areas to the extent it has the information to do so.[5]

II. THE COMMISSION'S DECEMBER 2006 SEAMS TECHNICAL CONFERENCE

In the *September 2006 Order*, the Commission directed the "Commission staff to convene a technical conference to assist the CAISO and parties outside the CAISO Control Area to identify seams issues that require resolution." (September 2006 Order at p. 490). On December 14 and 15, 2006, the Commission held the technical conference to address seams issues mandated by the *September 2006 Order*. The purpose of the technical conference was to provide parties an opportunity to identify and discuss solutions to resolve seams issues in the West, including alleged seams issues that exist between the CAISO and neighboring systems.

On November 17, 2006, the "Control Area Coalition" comprised of SMUD, TID, Imperial Irrigation District, Salt River Project and the Los Angeles Department of Water and Power filed pre-technical conference comments. In those comments the Control Area Coalition raised concerns that the CAISO's MRTU proposal "would increase congestion and loop flows at the interties and in neighboring control areas." (Control Area Coalition at p. 4). In support of this statement the Control Area Coalition states that:

> The MRTU locational marginal pricing ("LMP") re-dispatch of generation may significantly alter historic generation dispatch patterns and flow patterns in the CAISO and in the rest of the West. *Limitations to the FNM* will lead to increased re-disptach in real-time, *inaccurate LMP prices*, and, potentially, *infeasible schedules*. Additionally, limitations to the CAISO's FNM could result in CAISO system imbalances when too little generation is dispatched in certain areas and where too much generation is dispatched in other areas…[emphasis added]

---

2 *See September 2006 Order* at PP 45, 46. As noted earlier, the term "CAISO Control Area" is referred to as the "CAISO BAA" and "embedded" and "adjacent control areas" are referred to as "Integrated Balancing Authority Areas" or "IBAAs".

3 September 2006 Order at P 45.

4 *Id*.

5 *Id*. *See also* MRTU Tariff § 27.5.3.

(Control Area Coalition at p. 4, footnote 6).

Interestingly, the very deficiencies identified by the Control Area Coalition – limitations to the FNM, inaccurate LMPs, and infeasible schedules – are the very deficiencies the CAISO is seeking to remedy through the instant IBAA proposal.

The FNM limitations referred to by the Control Area Coalition include radial modeling of the interties. On November 30, 2007, the Control Area Coalition filed two whitepapers. One of those whitepapers was sponsored by ZGlobal Inc. ("ZGlobal Whitepaper"). As stated by the CAISO in its January 16, 2007, Post Technical Conference Comments on Seams Issues (CAISO comments at p. 9):

> The ZGlobal Whitepaper erroneously asserts that the CAISO's use of a radial model of external Control Areas for the purpose of predicting the impact of changes in interchange transactions schedules on internal CAISO transmission constraints will adversely impact the reliability of external control areas even though the CAISO uses a radial model today. The CAISO uses a radial model in part because WECC scheduling practices are based on the radial model. In fact, the use of the radial model by the CAISO has no implications for external control areas and is only relevant as to how the CAISO predicts impact of interchange transactions on the transmission constraints internal to the CAISO's Control Area.

See also Attachment A to the CAISO's comments, "Overview of CAISO Analysis of the Seams Issues Whitepaper prepared for the Control Area Coalition by ZGlobal Inc." prepared by Scott M. Harvey, Lorenzo Kristov and Mark Rothleder. In further refute of the Control Areas Coalition's comments that MRTU will adversely impact other control areas, the CAISO's January 16, 2007, comments stated:

> …there may be discrepancies between the Day-Ahead Schedule and Real-Time operations due to the difficulties under current scheduling prices in predicting the net changes in generation patterns that will result from changes in interchange transactions schedules. This is not a discrepancy caused or exacerbated by MRTU. Such discrepancies are instead a problem with the contract path approach used throughout the West today that does not consider loop flows. The CAISO reflects the West's use of this contract path approach through the use of a radial intertie model today, and MRTU does not change this practice. The CAISO agrees with parties that the contract path approach does create discrepancies between Day-Ahead and Real-Time which lead to Real-Time unscheduled flows and inefficient use of transmission resources. As discussed below, the CAISO stands ready to work with others in the region through the WECC to develop an improved approach based on a West-wide network model and an exchange of Day-Ahead scheduling information. However, these are not reasons to delay the implementation of MRTU.

(CAISO Comments at pp. 6-7). Finally, in its January 16, 2007, comments, the CAISO committed to work with neighboring Balancing Authority Areas, indicated that it was important to examine and work with each Balancing Authority Area individually, and that it was necessary to exchange data to identify issues that should be addressed. Specifically, the CAISO stated:

> The implementation of MRTU may create certain coordination issues at the boundaries of the CAISO with its neighbors. Because each of the Control Areas interconnected with the CAISO has unique features, these issues are not amenable to a "one size fits all" approach. Instead, the most effective way to address such issues is through cooperation between neighboring Control Areas on a bilateral basis. Indeed, the most appropriate approach to resolving such inter-Control Area issues are agreements between neighboring Control Areas which can be reflected in modifications to the existing bilateral Interconnected Control Area Operating Agreements between the CAISO and its neighboring Control Areas. This approach is consistent with the Commission's recognition, in the September 21 Order, that the CAISO has demonstrated that it is taking regional reliability into consideration by entering into Interconnected Control Area Operating Agreements with its neighboring Control Areas.
>
> The CAISO intends to identify any issues that should be addressed *based on an exchange of data* with those Control Areas embedded within the CAISO Control Area and immediately adjacent to the CAISO Control Area. The CAISO will then propose changes to existing ICAOAs based on these issues and meet with neighboring Control Areas to reach agreement on appropriate modifications to the ICAOAs. *The CAISO notes that each embedded or adjacent Control Area is likely to raise different coordination issues.* These differences are why the existing Interconnected Control Area Operating Agreements are individual agreements with different terms and conditions. It would be counter-productive to abandon these existing ICAOAs and start from scratch with a single West-wide agreement, as proposed by some parties. For those neighboring Control Areas who do not currently have an ICAOA with the CAISO (*e.g.*, new Control Areas that have formed in the past few years), the CAISO is prepared to develop a *pro forma* Interconnected Control Area Operating Agreement that can be used as a basis for bilateral discussions with any interconnected Control Area that wishes to enter into an agreement with the CAISO. [emphasis added]

CAISO Comments at pp. 12-13.

In the April 20, 2007 Order Granting In Part and Denying in Part Requests for Clarification and Rehearing, *California Independent System Operator Corporation*, 119 FERC ¶ 61,076 (April 20, 2007), the Commission reiterated that the need for better data exchange amoug control areas in the west is not an MRTU seams issue and encouraged participants to work through the WECC process to resolve these issues. The Commission stated:

> 208. The need for better data exchange among control areas in the West is not a seams issue related to MRTU. There was no disagreement among commenters that the exchange of data among control areas – for example the exchange of day-ahead load forecast, schedules and outages – will contribute to improved reliability and better enable operators to position the grid for the next day's operations. WECC adds that the West-wide System Model, currently under development, will provide information required for improved modeling efforts. Therefore, we encourage the commenters to work through the appropriate WECC committees to identify and put in place a process for exchange of data among WECC control areas and take advantage of the West-wide System Model. We expect the CAISO to participate fully in this process and direct it and neighboring control areas to include in their quarterly joint seams reports the status of efforts on data exchange and modeling.

The Commission also reiterated its support for better modeling of external areas and encouraged parties to pursue better exchange of data to enhance modeling improvements. Specifically, the Commission stated:

> 252. We believe that the full network model is an improvement over the current modeling of the CAISO grid, even if it models interties as radial lines. A more accurate modeling of the transmission grid outside of the CAISO may provide a better indication of the feasibility of the CAISO's day-ahead schedules by taking into account transmission constraints outside the CAISO. However, the modeling of the transmission system alone does not provide the full picture of grid conditions because, as we have discussed above, the loads, generation and interchange schedules of the control areas outside the CAISO also affect the flows within and outside of the CAISO. Therefore, to achieve better day-ahead modeling, an improved modeling of the transmission system in the full network model must be combined with an exchange of data among the WECC control areas.
>
> 253. As we discussed earlier, the need for better data exchange among control areas in the West is not a seams issue related to MRTU. Nor is the goal of improving the CAISO's modeling of its system an issue unique to MRTU. The exchange of data among control areas and improved modeling will contribute to improved reliability and better enable operators to position the grid for the next day's operations. WECC recognizes the importance of data exchange and accurate modeling and, to that end, has undertaken the "West-wide System Model." Accordingly, we again encourage the commenters to work through the appropriate WECC committees to identify and put in place a process for exchange of data among WECC control areas, including the possible implementation of the West-wide System Model.

Subsequent to the Commission's Seams Technical Conference, and consistent with the Commission's direction and the CAISO's commitments at the technical conference, the CAISO began to engage other Balancing Authority Areas regarding the necessary exchange of data and to develop a proposal regarding the treatment of the then-named embedded and adjacent control areas (now IBAAs) and to initiate discussions with those entities. The IBAA consultation process is described in the next section.

III. THE CAISO'S IBAA CONSULTATION PROCESS

During early 2007, the CAISO initiated an internal process to develop the design and implementation details for modeling and pricing IBAAs.[6] Once the CAISO had developed what it believed was a reasonable framework, the intent was to then work with potential IBAAs to secure their support for the modeling and pricing of interchange transactions between those IBAAs and the CAISO.

At the same time that the CAISO was developing its initial IBAA proposal, the CAISO began to engage external Balancing Authorities around the West regarding use of a detailed FNM and data requirements and needs regarding the use of a detailed FNM. In addition, the CAISO engaged these same entities in data sharing arrangements necessary to support the newly adopted mandatory NERC reliability standards. As detailed below, certain of the Balancing Authorities expressed concerns about providing information or data to the CAISO.

The following statements are excerpts from the Joint Seams Reports filed by the CAISO and Western, SMUD, Arizona Public Service Company (APS), Los Angeles Department of Water and Power (LADWP), Nevada Power Company (NevPo), Bonneville Power Administration (BPA), PacifiCorp, and included in the CAISO's First Quarter 2007 FERC Seams Report, Attachments A-H. The excerpts generally convey the nature of the CAISO's discussions with these entities regarding development of the MRTU FNM and related data exchange requirements.

Joint Report of CAISO and Western Area Power Administration

> *Development of a data sharing agreement governing the terms and conditions under which Western can provide real-time information to CAISO.* Western and the CAISO discussed the CAISO's FNM data needs, and the objective to help ensure an accurate power flow solution, that both optimizes use of the CAISO grid and improves reliability of grid operations in real time. Any such data exchanged will be proprietary and used only for reliability purposes. The CAISO explained its concept of "embedded/adjacent" control areas and need for both forward schedule data (internal generation levels, load distribution factors and Interchange), as well as the present real-time telemetry data. Both parties committed to a subsequent meeting to work out the details of the data needed, exchange mechanisms, and a contract to implement this data exchange. In a subsequent meeting on February 21, 2007, Western, CAISO and California-Mexico Reliability Coordinator discussed and outlined the type

6 The CAISO's original thinking regarding the modeling and pricing for IBAAs is detailed in Appendix 3 to the CAISO's December 14, 2007 "Discussion Paper Modeling and Pricing Integrated Balancing Authority Areas Under the California ISO's Market Redesign and Technology Upgrade Program" posted on the CAISO website at http://www.caiso.com/1cb4/1cb4e1a154060.pdf.

of information that should be exchanged. CAISO agreed to draft an initial agreement for Western's review.

Joint Report of CAISO and Sacramento Municipal Utility District

Data Sharing. Representatives discussed the possibility of developing a data sharing agreement governing the terms and conditions under which SMUD and the CAISO, can exchange reliability data, to better forward schedule use of their respective grids, for reliability purposes. Due to limited time, representatives agreed to hold subsequent discussions regarding such efforts.

Joint Report of CAISO and Arizona Public Service Company

Whether MRTU Full Network Model (FNM) and data exchange should be reciprocal to provide for better forward scheduling and facilitate use of their respective grids more reliably. APS was supportive of expansion of the CAISO's FNM to include a larger portion of the Western Interconnection, and specifically several segments of the APS system, to achieve greater accuracy of the forward power flow solution. Both company representatives expressed strong support for a bi-lateral and reciprocal data exchange agreement, governing the terms and conditions under which APS and the CAISO, can exchange reliability data, to better forward schedule use of their respective grids, for reliability purposes. APS agreed that Moenkopi – PV – Navajo 500 kV should be incorporated into the CAISO FNM. APS and the CAISO agreed with the need for data sharing of schedule and operations data, to be used by both control areas, to optimize their respective planned, real time grid operation, with the mutual objective of enhancing grid reliability. Jerry Smith of APS reported on behalf of WECC, that the WECC Market Interface Committee is committed to some form of data sharing agreement, governing the terms and conditions under which APS and the CAISO, could exchange reliability data.

Joint Report of CAISO and Los Angeles Department of Water and Power

Data Exchange. CAISO expressed its desire to recognize all physical constraints (transmission loading) in the Day Ahead Market. In order to do so, the CAISO may need certain operational data from adjacent control areas to achieve this purpose. CAISO staff stated that this data is for reliability, not for marketing purposes. LADWP representatives expressed a concern that data exchange would be problematic for LADWP until the CAISO could demonstrate that the data will not be used by CAISO for anything other than reliability uses. Representatives agreed to continue discussing the issue of data exchange.

Joint Report of CAISO and Nevada Power Company/Sierra Pacific Power Company

MRTU Full Network Model and Data Exchanges. CAISO expressed its belief that data exchanges should be reciprocal to better forward schedule use of their respective grids, for reliability purposes only. NevPo/SPP representatives were supportive of exchange of scheduling data on "Grid/Reliability side only" and insisted that data exchange must be reciprocal. The CAISO explained its role as a market and grid and its limitation in sharing market proprietary data as such data is held in confidence and not shared externally. NevPo/SPP and the CAISO representatives agreed on the need for data sharing of schedule and operations data, to be used by both control areas, to optimize their respective planned, Real Time grid operation, with the mutual objective of enhancing grid reliability.

Joint Report of CAISO and Bonneville Power Administration

West-wide FNM. BPA expressed support for the eventual adoption of the FNM approach within the WECC area if the model included the capability to model loop flow. CAISO explained the need for embedded and adjacent balancing authority data for FNM reliability purposes, asked for BPA's support, and explained that LMP pricing is integral to the FNM optimum power flow solution, efficient transmission usage, forward mitigation of loop flow, economic uses of resources, and thus, the reliable operation of grid. CAISO also stated that it does not and would not release sensitive market proprietary data.

Joint Report of CAISO and PacifiCorp

Current modeling limitations in the Western interconnection. CAISO's current proposal under MRTU is to use the Full Network Model ("FNM") only for California and model the balance of Western Interconnection as a radial line. PacifiCorp's Commercial and Trading raised several key questions on how the radial lines are modeled, what capacity is presented in the case for joint facilities and areas that operated under current nomogram. PacifiCorp's Commercial and Trading is concerned that such modeling approach could give false congestion signal or force unanticipated redispatch in real time. The CAISO described its desire to be able to use the Full Network Model ("FNM") optimization to minimize loop flow and that this would best be accomplished through a more complete FNM of the whole west. Recognizing the current limitations in the West, the CAISO discussed its application of a radial model for adjacent balancing authorities (control areas), and the difference between its modeling of embedded balancing authorities, whose systems are actually incorporated into the CAISO FNM. CAISO will determine and further discuss with PacifiCorp's Commercial and Trading on how specific the interties, such as Palo Verde and Four Corners are modeled in the current FNM.

Based on these representations, the CAISO reexamined its initial internal draft IBAA proposal and determined that it may be able to achieve its objectives – modeling accuracy and cost-effective congestion management – through a less data-intensive proposal. The CAISO was concerned that implementation of the IBAA methodology and functionality may prove difficult if Balancing Authorities are unwilling to provide the necessary data and that this may delay the start of MRTU. At that time the CAISO also decided to focus on those Balancing Authority Areas that it believed were critical to model for MRTU start up, namely the SMUD and TID Balancing Authority Areas. The CAISO proceeded to outline and develop an alternative IBAA proposal that it began to discuss in concept with SMUD and Western and other parties beginning in late Spring/early Summer 2007.

As summarized in the Joint Reports filed as part of the CAISO's Second Quarter 2007 FERC Seams Report, the CAISO began to consult with SMUD, Western, TID and others beginning in June 2007. The excerpts generally convey the nature of the CAISO's discussions with these entities regarding development of the CAISO's then-proposed IBAA proposal.

Joint Report of CAISO and Western Area Power Administration

> *Modeling and Treatment of Embedded/Adjacent Control Areas Under MRTU* (Meeting between Western, SMUD and CAISO) – On June 5, 2007, representatives of Western, SMUD, and the CAISO met to discuss the modeling and settlement treatment for Embedded/Adjacent Control Areas (ECAs/ACAs) under MRTU. The discussions focused on how the CAISO proposed to represent (in the MRTU-related network models and systems) the SMUD/Western control area and how the CAISO will establish related prices. The CAISO explained that its original proposal was to model and price the full detail of the ECAs/ACAs, thereby establishing and revealing Locational Marginal Prices (LMPs) for all resources and scheduling points within the ECA/ACA. The CAISO also explained that to do so, the CAISO would need each ECA/ACA to provide detailed information regarding the scheduling of physical resources within the ECA/ACA, including both "base schedules" regarding how the ECA/ACA would serve its internal load as well as imports/exports and wheel throughs to and on the CAISO system. At the June 5th meeting, the CAISO indicated that it had revised its approach based on concerns raised by SMUD and Western regarding the establishment of LMPs within their own systems, the voluminous data requirements of the CAISO's original proposal and the fact that such a requirement would require SMUD to provide third-party data, which SMUD has not been authorized to release. The CAISO explained that while its current proposal provided for the detailed modeling of the ECA/ACA transmission system (to ensure an accurate and reliable solution for the CAISO system), the CAISO would not enforce any of the constraints internal to the ECA/ACA system and proposed not to establish LMPs for internal ECA/ACA resources. Under the new approach, the CAISO would utilize the existing scheduling points with the ECAs/ACAs and offered to price/settle at those tie points or on an aggregated (*i.e.*, hub) basis. Both SMUD and Western indicated that new CAISO approach was a move in the right direction. The CAISO asked that SMUD and Western consider the pricing/settlement options outlined and that the parties meet again to discuss a final proposal.
>
> ********

Development of a Data Sharing Agreement - At the January 22, 2007, meeting between Western and the CAISO, Western and the CAISO discussed the CAISO's data needs for its Full Network Model (FNM), and the CAISO's objective to ensure an accurate power flow solution that both optimizes use of the CAISO grid and improves reliability of grid operations in real time. The parties agreed that any such data exchanged will involve proprietary data and should be used only for operating purposes (*i.e.*, not for market purposes). At the June 13th meeting, Western continued to express concerns regarding the use and source of the data by the CAISO. Western's principal concern is whether it could be financially liable for providing data to the CAISO that later turns out to be inaccurate. Western stated that it is concerned about possible exposure to both FERC's new market rules on providing inaccurate or false information and possible exposure to financial liabilities if the CAISO establishes what turns out to be incorrect market prices based any inaccurate information unintentionally provided by Western. The CAISO acknowledged Western's concerns and agreed to explore ways to provide Western the required assurances and protection.

Joint Report of CAISO and Turlock Irrigation District

MRTU Full Network Model & Data Exchange Needs to Reliably Forward Schedule Use of the Respective Grids - TID expressed a preference for a independent entity to hold any exchanged data, *e.g.*, the California-Mexico Reliability Coordinator. TID asked about the Western and SMUD reactions to this same CAISO data exchange proposal. The CAISO presented the need for the sharing of schedule and operations data, to be used by both control areas, to optimize their respective planned, Real Time grid operation, with the mutual objective of enhancing grid reliability. The CAISO indicated that it has scheduled working session with Western and SMUD to implement some form of data sharing for this purpose.

Joint Report of CAISO and Sacramento Municipal Utility District

Development of a Data Sharing Agreement - At the April 20, 2007, meeting between SMUD and the CAISO, SMUD and the CAISO discussed the data information requirements and needs related to the new National Reliability Standards, as implemented by FERC, the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). Both SMUD and the CAISO expressed the need to coordinate on and resolve data exchange issues to comply with the new national standards and to improve the reliability of grid operations in real time. The parties agreed that any such data exchanged will be proprietary and used only for operating purposes (i.e., not for market purposes). At the April 20th meeting, SMUD continued to express concerns regarding the use and source of the data by the CAISO. The CAISO acknowledged SMUD's concerns and agreed to explore ways to provide SMUD the required assurances it sought. Subsequent to the

April 20th meeting, SMUD and the CAISO were able to mutually agree on a temporary means to provide the appropriate data to one another and ensure continued compliance with all applicable reliability standards. SMUD and the CAISO continue to work towards a permanent data sharing arrangement.

****

Modeling and Treatment of Embedded/Adjacent Control Areas Under MRTU (Meeting between Western, SMUD and CAISO) – On June 5, 2007, representatives of Western, SMUD, and the CAISO met to discuss the modeling and settlement treatment for Embedded/Adjacent Control Areas (ECAs/ACAs) under MRTU. The discussions focused on how the CAISO proposed to represent (in the MRTU-related network models and systems) the SMUD/Western control area and how the CAISO will establish related prices. The CAISO explained that its original proposal was to model and price the full detail of the ECAs/ACAs, thereby establishing and revealing Locational Marginal Prices (LMPs) for all resources and scheduling points within the ECA/ACA. The CAISO also explained that to do so, the CAISO would need each ECA/ACA to provide detailed information regarding the scheduling of physical resources within the ECA/ACA, including both "base schedules" regarding how the ECA/ACA would serve its internal load as well as imports/exports and wheel throughs to and on the CAISO system. At the June 5th meeting, the CAISO indicated that it had revised its approach based on concerns raised by SMUD and Western regarding the establishment of LMPs within their own systems, the voluminous data requirements of the CAISO's original proposal and the fact that such a requirement would require SMUD to provide third-party data, which SMUD has not been authorized to release. The CAISO explained that while its current proposal provided for the detailed modeling of the ECA/ACA transmission system (to ensure an accurate and reliable solution for the CAISO system), the CAISO would not enforce any of the constraints internal to the ECA/ACA system and proposed not to establish LMPs for internal ECA/ACA resources. Under the new approach, the CAISO would utilize the existing scheduling points with the ECAs/ACAs and offered to price/settle at those tie points or on an aggregated (*i.e.*, hub) basis. Both SMUD and Western indicated that new CAISO approach was a move in the right direction. The CAISO asked that SMUD and Western consider the pricing/settlement options outlined and that the parties meet again to discuss a final proposal.

Discussions with SMUD, Western, TID and other parties continued into the third quarter of 2007, as summarized in excerpts from the Joint Reports filed as part of the CAISO's Third Quarter 2007 FERC Seams Report. The excerpts generally convey the nature of the CAISO's discussions with these entities regarding development of the CAISO's then proposed IBAA proposal.

Joint Report of CAISO and Sacramento Municipal Utility District

Modeling and Treatment of Embedded/Adjacent Control Areas Under MRTU (Meeting between SMUD, Western, Turlock, Modesto, Redding, and CAISO) – On August 21, 2007, representatives of SMUD, Western, Turlock, Modesto, Redding, and the CAISO met to discuss the modeling and settlement treatment for Embedded/Adjacent Control Areas (ECAs/ACAs) under MRTU. The discussions focused on how the CAISO proposed to represent (in the MRTU-related network models and systems) the SMUD/Western and TID control areas and how the CAISO will establish related prices. The CAISO made a short presentation describing how the SMUD/Western and TID control areas were originally intended to be modeled. The CAISO explained that its original proposal was to model and price the full detail of the ECAs/ACAs, thereby establishing and revealing Locational Marginal Prices (LMPs) for all resources and Scheduling Points within the ECA/ACA. The CAISO also explained that to do so, the CAISO's original proposal would have required each ECA/ACA to provide detailed information regarding the scheduling of physical resources within the ECA/ACA, including both "base schedules" regarding how the ECA/ACA would serve its internal load as well as imports/exports and wheel throughs to and on the CAISO system. SMUD and Western had earlier provided feedback indicating concerns related to the sensitivity of the CAISO establishing LMPs for the neighboring ACA systems in the SMUD and TID control areas. SMUD, for example, noted that it was not able, nor should it be required, to provide its own internal schedules to the CAISO. SMUD pointed out that such a requirement would be extremely invasive, in addition to being overly burdensome and costly. Moreover, SMUD, as the Balancing Authority, had no authority to compel entities within its boundaries to provide such data to the CAISO. Thus, from SMUD's viewpoint, the CAISO's original proposal was neither realistic nor achievable.

The CAISO reiterated to SMUD, Western, and Western's customers at the August 21 meeting that the CAISO had revised its approach based on the concerns raised by SMUD and Western regarding the establishment of LMPs within their own systems. These concerns were that the CAISO's original approach constituted what SMUD and Western viewed as overreaching by the CAISO, and that the original approach imposed voluminous data requirements. The CAISO indicated that, although its revised approach still allows the CAISO to model ECA/ACA transmission systems to ensure an accurate solution for the CAISO system, the CAISO would not be determining any of the constraints internal to these ACA systems and also agreed to calculate or establish LMPs only for aggregated resources that are scheduled in the CAISO markets, not for their internal ACA resources. Under its revised approach, the CAISO indicated it would utilize the existing Scheduling Points with the SMUD and TID ACAs for submission of schedules in the CAISO markets. The CAISO also stated that it was considering three pricing options: 1) pricing at the Scheduling Points (interties); 2) pricing on a large hub basis, e.g., SMUD/Western would be a single hub; or 3) pricing on an aggregate sub-system basis wherein the CAISO would establish separate prices for the SMUD, Western, Turlock, Modesto and other possible areas.

The CAISO stated that, at that time, it favored the aggregate sub-system based pricing approach wherein the CAISO would establish separate prices for the

SMUD, Western, Turlock, and Modesto areas. The CAISO stated that it could also establish sub-system prices for Redding, the City of the Roseville, and other smaller metered areas. The CAISO stated that it favored the sub-system based approach because an intertie-based pricing approach could create inappropriate scheduling/pricing incentives wherein customers would schedule at certain points to take advantage of perceived price differences between Scheduling Points even though they may not intend to dispatch and use their resources in a manner consistent with their submitted schedules. The CAISO also stated that it did not favor a large hub price, since a large hub price may unnecessarily diminish price signals and that such prices would not truly reflect the actual nature of sub-system based operations. The CAISO represented that it believed both those pricing options were less optimal than a sub-system based pricing regime and may be odds with the broader objectives of MRTU. The CAISO also stated that it may still need additional information from the ACAs to ensure that the sub-system pricing approach aligns well with the ACAs' actual use of the grid.

SMUD, Western and Western's other customers indicated that CAISO's approach appeared to be preferable to the CAISO's more data-intensive original ACA/ECA proposal, which SMUD and the other ACAs viewed as a non-starter. However, SMUD stated that it requires more information regarding the modeling and pricing details so as to better understand the advantages and disadvantages of both the modeling and settlement treatment options. SMUD, as well as Western and other Western customers also made the observation that not every action occurring in the SMUD control area had a material impact on operations in the CAISO control area and that, conversely, there were some instances where CAISO actions did have a deleterious impact on operations in the Western/SMUD control area. Additionally, these parties observed that, as part of the overall process to select a preferred modeling and settlements approach, sufficient safeguards were needed to protect all parties so that, over time, as flows and operations change, a mechanism would be in place not only to review those changes in operations and flows, but also to make the appropriate corresponding changes to the models being used to develop LMPs.

SMUD and Western also raised a concern as to the impact of the CAISO's pricing proposal on the ACAs' congestion revenue rights (CRRs) nominations. Western noted that the CAISO had finalized its white paper reflecting its revised approach only after the initial due date for submissions for Tier 1 and on the date Tier 2 CRR nominations opened for submissions. Western accordingly requested consideration from the CAISO for modification of its CRR allocations and allocation requests in the event the changes in the CAISO's approach turned out to have a material effect on Western's nominations. SMUD similarly noted that it was planning to nominate CRRs in the upcoming CRR nomination process, commencing in September 2007, based upon its established assumption that its CRR sinks were Scheduling Points. Thus, it questioned how a hub nominated as a CRR sink might differ from a Scheduling Point. More specifically, it questioned whether such a change might negatively impact SMUD's CRR nominations or allocations. The CAISO stated that it was preparing a detailed paper on the issue that it would present to SMUD and other affected ECAs/ACAs.

The CAISO asked that SMUD consider the outlined pricing/settlement options and that the parties meet again to discuss a final proposal once the CAISO has completed and distributes its technical paper on the matter.

On September 10, 2007, SMUD sent an e-mail request to the CAISO, asking for assurances that such a proposed change to a hub would not negatively impact SMUD's CRR nominations--which were now in progress. SMUD noted:

> SMUD is basing its CRR nominations upon its analysis of LMP prices at SMUD's various Scheduling Points, not at a yet-to-be determined SMUD trading hub. Consequently, the prospect exists that SMUD will be basing its CRR nominations on a set of assumptions that are likely to change. Accordingly, SMUD requires some form of assurance from the ISO that it will not be prejudiced by some future changes to how LMPs will be settled for SMUD and other similarly-situated out-of-control-area LSEs. SMUD notes that all other LSEs have the benefit of knowing the settlement treatment of their sink locations (for most, the load aggregation points or "LAPs").

The CAISO responded to SMUD, by letter from Deborah Le Vine, dated September 13, 2007 (Letter), assuring SMUD "that it [SMUD] has certainty its pricing settlement option ultimately adopted through the resolution of the ACA issue will not be inconsistent with its CRR settlement." Letter at 2. However, SMUD believes there are two primary CRR-related issues associated with moving from intertie-specific pricing to a hub. The first pertains to the financial settlement of CRRs that would result from such a change. This, the CAISO has assured SMUD by its Letter, will not be affected. In SMUD's view, what has not been addressed is the question as to how SMUD's CRR nominations might have changed with a hub (aggregation) rather than a Scheduling Point as its CRR Sink. That is, whether SMUD would wish to nominate an entirely different set or quantity of CRRs had it compared the marginal congestion price differences between a specific source and sink, when that sink is an aggregated hub, versus a specific Scheduling Point. This question, SMUD stated, has not been addressed by the CAISO and in SMUD's view remains open.

As noted above, the CAISO has explained that it will ensure, consistent with the applicable CAISO Tariff provisions and SMUD's demonstration of qualified resources, that SMUD's sources and sinks, and the calculation of congestion costs, are consistent between the CAISO's CRR settlements and the congestion charges in the Day-Ahead Market. The CAISO stated its view that if SMUD requests and receives CRRs that match the schedules that it will submit in the CAISO's market, its CRRs will provide the necessary hedge from potential congestion costs.[7]

[7] The CAISO further explained its position and commitment on this issue in the October 5, 2007, ACA paper. The parties will discuss the ACA paper, and SMUD's response to it, in greater detail in the next status report.

Regarding SMUD's second concern, the CAISO stated its view that this issue is not related to CRRs, but is related to the ultimate pricing approach adopted for ECAs/ACAs. The CAISO stated that it had sought to ensure that the ECA/ACA design is consistent with the core design principles and objectives of the larger MRTU design. In its view, the ECA/ACA design adopted results in feasible forward schedules and related prices aligned with real-time operating requirements. Therefore, while the CAISO believes that it has addressed SMUD's concerns with respect to SMUD's exposure to potential CAISO congestion costs, the CAISO believes that further discussion on the proposed modeling and settlement of ECAs/ACAs is needed.

******

Issues Requiring Resolution Before MRTU Start-up- Identification of seams issues requiring resolution prior to MRTU start-up are a priority to SMUD and the CAISO. The parties have identified for action issues related to finalizing the modeling and settlement treatment of ECAs/ACAs under MRTU. The CAISO and SMUD are continuing to work to address the above item and are hopeful that a resolution of these items can be implemented before the start of MRTU.

Joint Report of CAISO and Western Area Power Administration

The CAISO made a short presentation describing how the SMUD/Western and TID control areas were originally intended to be modeled and represented in its MRTU-related network models and systems and how the data derived from these models would be used by the CAISO to establish price. The CAISO explained that it originally intended to model and price the full detail of the ECAs/ACAs, thereby establishing and revealing Locational Marginal Prices (LMPs) for all resources and Scheduling Points within the ECA/ACA. The CAISO explained that in order to accomplish this level of pricing detail, each ECA/ACA would have to provide detailed information regarding the scheduling of physical resources within the ECA/ACA, including both "base schedules" regarding how the ECA/ACA would use to serve its internal load and imports/exports and wheel throughs to and on the CAISO system.

After meeting with SMUD and Western, and getting feedback which indicated concerns related to the sensitivity of the CAISO establishing LMPs for the neighboring ECAs/ACAs systems, the CAISO decided to revise its overall approach. At the August 9 and 21 meetings the CAISO indicated that although its revised approach still allowed the CAISO to model the ECA/ACA transmission system to ensure an accurate and reliable solution for the CAISO system, the CAISO would not be determining any internal constraints to the ECA/ACA system and also agreed not to calculate or establish any LMPs for internal ECA/ACA resources. Under its revised approach, the CAISO indicated that it could consider utilizing the existing Scheduling Points with the ECAs/ACAs for pricing and settlement or in the alternative, on an aggregated (i.e., hub) price. The CAISO also stated that it was considering three pricing options: 1) pricing at the Scheduling Points (interties); 2) pricing on a large hub basis, e.g., SMUD/Western as a single hub; or 3) pricing on a aggregate sub-subsystem basis wherein the CAISO would establish separate prices for the SMUD, Western, Turlock, Modesto, Redding, and other possible areas.

The CAISO stated at both meetings that its preference was the aggregate sub-system based pricing approach wherein the CAISO would establish separate prices for the SMUD, Western, Turlock, and Modesto areas. The CAISO stated that it could also establish sub-system prices for Redding, the City of the Roseville, and other smaller metered areas. The CAISO stated that it favored the sub-system based approach because an intertie-based pricing approach could create inappropriate scheduling/pricing incentives wherein customers would schedule at certain points to take advantage of perceived price differences between scheduling points even though they may not intend to dispatch and use their resources in a manner consistent with their submitted schedules. The CAISO also stated that it did not favor a large hub price, since a large hub price may unnecessarily diminish price signals and that such prices would not truly reflect the actual nature of sub-system based operations. The CAISO represented that it believed both those pricing options were less optimal than a sub-system based pricing regime and may be at odds with the broader objectives of MRTU. The CAISO also stated that certain reporting/information requirements may still be needed to ensure that the sub-system pricing approach aligns well with the ECAs/ACAs actual use of the grid.

Both Western and its customers indicated that CAISO’s revised approach appeared to be preferable to the CAISO’s more data-intensive original ACA/ECA proposal. However, Western and its customers stated that they required more information related to the modeling and pricing details before they could make an informed decision on the acceptability of any CAISO proposal. The CAISO stated that it was preparing a detailed paper on the issue that it would present to Western, its customers, and other affected ECAs/ACAs. The CAISO asked that Western and its customers consider the outlined pricing/settlement options and that the parties meet again to discuss a final proposal once the CAISO has completed and distributes its technical paper on the matter.[8]

During the discussions Western, SMUD, and its customers observed that it was important to note that not every action occurring in the SMUD control area deleteriously impacted operations in the CAISO control area, and that there were some instances where CAISO actions had deleterious impacts upon the operations of the Western-SMUD control area. Additionally, Western, SMUD, and its customers observed that as part of this overall process to select a preferred modeling and settlements approach, sufficient safeguards were needed to protect both parties so that over time, as flows and operations changed, that a mechanism was in place not only to review those changes in operations and flows, but to also

[8] The CAISO distributed a paper on the modeling and settlement treatment of ECAs/ACAs to Western and other affected parties on October 5, 2007. Western has arranged meetings with Modesto, Redding, SMUD, Turlock, and other potentially impacted stakeholders during the month of October in order to review the CAISO’s latest white paper.

make the appropriate corresponding changes to the models being used to develop LMPs.

Western noted that the CAISO had finalized its white paper reflecting its revised approach only after the initial due date for submissions for Tier 1 Congestions Revenue Right (CRR) nominations and on the date Tier 2 CRR nominations opened for submissions. To the extent that Western's selection of a preferred modeling option at this time affects or impacts its current CRR allocation or allocation requests, Western requests consideration from the CAISO for modification of its CRR allocations and allocation requests in the event that any differences may turn out to be material.

As noted above, on October 5, 2007, the CAISO distributed a paper on the modeling and settlement treatment of ECAs/ACAs to Western and other affected parties. In that paper the CAISO stated , in part, that, "The CAISO recognizes that the amount of Congestion cost that will be charged in the Day-Ahead Market for Schedules to or from an ACA will need to be consistent with the proposed pricing approach, but this does not affect the acquisition of CRRs whose purpose is to offset costs associated with Congestion costs that occur in the Day-Ahead Market…Therefore, the ultimately adopted pricing approach should not impact participation in the CRR allocation process for acquiring CRRs whose purpose is to offset Congestion costs that occur in the Day-Ahead Market."

The CAISO acknowledges that its ECA/ACA paper (provided to Western on October 5, 2007) was distributed after the CRR Tier 1 nomination process was concluded and at the start of the CRR Tier 2 nomination process. That said, the CAISO believes that in discussions that took place prior to Tier 1 nominations with Western and others, that the CAISO clearly indicated the pricing/settlement options under consideration and that the CAISO was uncomfortable with a scheduling point-based settlement option.

****

Development of a data sharing agreement governing the terms and conditions under which Western can provide real-time information to CAISO. Western and the CAISO discussed the CAISO's Full Network Model FNM data needs, and the objective to help ensure an accurate power flow solution, that both optimizes use of the CAISO grid and improves reliability of grid operations in real time. The parties agreed that any such data exchanged will be proprietary and used only for operating purposes (i.e., not for market purposes). The CAISO explained its concept of "embedded/adjacent" control areas and need for both forward schedule data (internal generation levels, load distribution factors and Interchange), as well as the present real-time telemetry data. Both parties committed to a subsequent meeting to work out the details of the data needed, exchange mechanisms, and a contract to implement this data exchange. Western acknowledges receipt of a draft agreement from the CAISO. In attempting to adapt this agreement from a regional to an agency-wide agreement, timely completion of this document has been delayed because of internal coordination issues with other Western regional offices. Western regrets this delay and remains committed to resolving its internal coordination issues as expeditiously as possible so that an agreement can be submitted shortly for the CAISO's review.

Joint Report of CAISO and Turlock irrigation District

Modeling and Treatment of Embedded/Adjacent Control Areas Under MRTU (Meetings between Turlock, Western, Modesto, Redding, SMUD and CAISO) – On August 9 and 21, 2007, representatives of Turlock, Western, Modesto, Redding, SMUD and the CAISO met to discuss the modeling and settlement treatment for Embedded/Adjacent Control Areas (ECAs/ACAs) under MRTU. The discussions focused on how the CAISO proposed to represent (in the MRTU-related network models and systems) the TID and SMUD/Western control areas and how the CAISO will establish related prices. The CAISO explained that its original proposal was to model and price the full detail of the ECAs/ACAs, thereby establishing and revealing Locational Marginal Prices (LMPs) for all resources and Scheduling Points within the ECA/ACA. The CAISO also explained that to do so, the CAISO's original proposal would require each ECA/ACA to provide detailed information regarding the scheduling of physical resources within the ECA/ACA, including both "base schedules" regarding how the ECA/ACA would serve its internal load as well as imports/exports and wheel throughs to and on the CAISO system.

At the August 9th and 21st meetings the CAISO reiterated to Turlock, Western, Western's other transmission customers, and SMUD that the CAISO had revised its approach based concerns raised by SMUD and Western regarding the establishment of LMPs within their own systems and the voluminous data requirements of the CAISO's original proposal. The CAISO explained that while its current proposal provided for the detailed modeling of the ECA/ACA transmission system (to ensure an accurate and reliable solution for the CAISO system), the CAISO would not enforce any of the constraints internal to the ECA/ACA system and proposed not to establish LMPs for internal ECA/ACA resources. Under the new approach, the CAISO would utilize the existing Scheduling Points with the ECAs/ACAs and offered to price/settle at those tie points or on an aggregated (i.e., hub) basis. The CAISO stated that it was currently considering three pricing options: 1) pricing at the Scheduling Points (interties); 2) pricing on a large hub basis, e.g., SMUD/Western would be one hub; or 3) pricing on a aggregate sub-subsystem basis wherein the CAISO would establish separate prices for the Turlock, SMUD, Western, Modesto and other possible areas.

The CAISO stated that at that time, it favored aggregate sub-system based pricing approach wherein the CAISO would establish separate prices for the Turlock, SMUD, Western, and Modesto areas. The CAISO stated that it could also establish sub-system prices for Redding, the City of the Roseville, and other potential areas. The CAISO stated that it favored the sub-system based approach because an intertie-based pricing approach could create inappropriate scheduling/pricing incentives wherein customers would schedule at certain points to take advantage of perceived price differences between Scheduling Points even though they may not intend to dispatch and use their resources in a manner consistent with their submitted schedules. The CAISO also stated that it did not favor a large hub price, since a large hub price may unnecessarily diminish price signals and that such prices would not truly reflect the actual nature of sub-system based operations. The CAISO represented that it believed both those pricing options were less optimal than a sub-system based pricing regime and may be odds with the broader objectives of MRTU. The CAISO also stated that certain reporting/information requirements may still be needed to ensure that the sub-system pricing approach aligns well with the ECAs/ACAs actual use of the grid.

Turlock indicated that CAISO's approach appeared to be preferable to the CAISO's more data-intensive original ACA/ECA proposal. However, Turlock stated that it requires more information regarding the modeling and pricing details so as to better understand the advantages and disadvantages of both the modeling and settlement treatment options. The CAISO stated that it was preparing a detailed paper on the issue that it would present to Turlock and other affected ECAs/ACAs. The CAISO asked that Turlock consider the outlined pricing/settlement options and that the parties meet again to discuss a final proposal once the CAISO has completed and distributes its technical paper on the matter.

****

Issues Requiring Resolution Before MRTU Start-up- Identification of seams issues requiring resolution prior to MRTU start-up are a priority to Turlock and the CAISO. The parties have identified for action issues related to the finalizing the modeling and settlement treatment of ECAs/ACAs under MRTU. The CAISO and Turlock are continuing to work to address the above item and are hopeful that a resolution of these items can be implemented before the start of MRTU.

As evidenced from excerpt below from the CAISO-Western Joint Report included in the CAISO's Fourth Quarter 2007 FERC Seams Report, by the fourth quarter of 2007, discussions between the CAISO and the proposed IBAAs were no longer moving toward resolution.

Joint Report of CAISO and Western Area Power Administration

<u>Modeling Transactions in Certain Balancing Areas</u>

As reported in the CAISO and Western's Second Quarter 2007 Joint Seams Report, the CAISO first introduced its proposal for modeling certain adjacent balancing areas (BA) including those operated by the Sacramento Municipal Utility District (SMUD), Turlock Irrigation District (TID), and Western Area Power Administration (Western) on June 5, 2007. As reported in the Third Quarter 2007 CAISO-Western Joint Seams Report, the parties further discussed this issue on August 9, 2007, and

August 21, 2007. The CAISO subsequently provided Western, SMUD and TID a proposal in writing on October 5, 2007. The CAISO and Western most recently exchanged letters outlining our respective positions on November 14th and December 6th. A face-to-face discussion occurred on December 11th, and was followed up by a January 4, 2008, letter from Western and its IBAA counterparts to the CAISO. Additionally, Western and other IBAA operators (e.g., SMUD and TID) and IBAA participants (*e.g.*, Modesto Irrigation District, Cities of Redding and Roseville, U.S. Bureau of Reclamation, and the U.S. Department of Energy) either attended or dialed-in on two CAISO-hosted meetings where the IBAA proposal was discussed with other CAISO stakeholders. The CAISO and Western continue to have philosophical differences with respect to the CAISO's proposed new approach for modeling transactions (*i.e.*, prices, schedules, and settlements) from certain adjacent BAAs. *Western believes that this is a critical issue that must be mutually resolved before MRTU is implemented.*

In short, Western believes that the CAISO's proposal is not timely, is incomplete, and lacks detailed supporting analyses. Additionally, it appears from Western's perspective that the proposal is being implemented in a piecemeal, rather than a comprehensive approach. Western believes that the proposal's implementation may cause unintended impacts which may not only disadvantage Western and certain other BAA operators and their participants, but may also inadvertently result in discriminatory treatment *vis a vis* other market participants. In addition, Western is concerned that the proposal may devalue the existing investment in transmission infrastructure made by Western and other impacted BA members under a legacy regulatory scheme.

Western also believes that given what it represents is the relatively late finalization of the proposal, and in the event that potential financial harm is shown to Western, that the CAISO should consider revisiting its allocation of congestion revenue rights (CRR) as Western's CRR decisions were made under different scheduling assumptions. Western believes that this proposal in its entirety must be mutually resolved and the CAISO must file and receive approval from FERC before the proposal can be implemented. Throughout this process, Western was under the impression that the CAISO would use a more collaborative approach and as a result, the CAISO would not consider implementing it unilaterally as the CAISO is currently proposing.

The CAISO does not concur with Western's positions. As provided for in the conditionally-approved MRTU Tariff language, the CAISO has always intended to address the unique circumstances of the previously named Adjacent/Embedded Control Areas and that, as acknowledged in the Commission's September 21, 2006, Order on MRTU, the Commission recognized the need for the CAISO to work with the appropriate entities to obtain the information necessary to model, and establish the appropriate settlement treatment of, IBAAs. The CAISO has endeavored to work with Western and other affected IBAAs and, despite best efforts, has been unable to reach agreement. Notwithstanding the fact that the parties were unable to reach consensus, the CAISO believes that there exists a well-articulated rationale for the need to implement its proposal and that the proposal is well supported by the facts and underlying studies. The CAISO has also taken the position that it has the general authority under the conditionally approved MRTU Tariff language to implement its proposed modeling approach. Moreover, the CAISO does not believe that it is implementing its proposal in a piecemeal fashion. The Commission previously acknowledged the need for the CAISO to work with other BAAs to obtain the requisite information for accurately modeling these entities in the CAISO's MRTU models, systems and applications. To date, the CAISO has only been able to complete modeling of the SMUD/Western and TID systems and portions of the transmission system in Southern California/Desert Southwest. Moreover, and with respect to Western's concerns regarding the impact of the proposal on its CRRs, the CAISO has previously clarified that the proposed modeling detail was included in the Network Model used for CRR allocation and auction purposes and, as stated in the CAISO's discussion paper, the CAISO will ensure that entities allocated CRRs to/from the affected points will continue to receive the intended hedge against congestion costs (in other words, the CAISO will ensure that market congestion and CRRs are settled on a consistent basis). That said, the CAISO appreciates the concerns raised by Western and others regarding the efficacy of existing CAISO tariff language regarding this matter, and is further considering whether there is a need to further supplement the CAISO's existing MRTU Tariff language.

As of the date of this filing, the CAISO plans to file its IBAA proposal at the Commission on or around February 15, 2008. The CAISO's filing will include proposed CAISO Tariff changes that appropriately reflect implementation of the CAISO's IBAA proposal.

In summary, the CAISO engaged in a consultation with the IBAA entities from approximately June 2007 though December 2007. On October 4, 2007, the CAISO sent the IBAA entities a draft document that outlined the CAISO's then-current IBAA proposal and the supporting rationale. On November 14, 2007, SMUD responded to the CAISO indicating that it did not support the CAISO's IBAA proposal. The CAISO responded to certain of the issues raised by SMUD in a letter dated December 6, 2007, and subsequently met with representatives of SMUD, Western and TID on December 11, 2007. At that time, based on IBAA entity opposition to the CAISO's then-proposed IBAA proposal and because of the then-impending February 1, 2008, MRTU start date, the CAISO determined that it was appropriate and prudent to initiate a broader stakeholder discussion and finalize the proposal prior to MRTU start up. On December 14, 2007, the CAISO posted two discussions papers that detailed the CAISO's then-proposed IBAA proposal, thus initiating the CAISO's broader stakeholder process discussed in the next section.

IV. THE CAISO'S IBAA STAKEHOLDER PROCESS

Beginning in December, 2007, and lasting through early May, 2008, the CAISO conducted a stakeholder process regarding its IBAA proposal. As detailed in Attachment B to the CAISO's May 13, 2008, Memorandum to the CAISO Governing Board, the CAISO's IBAA stakeholder process included the following:

Stakeholders submitted rounds of written comments to the CAISO on the following dates:

- Round One, 01/07/08
- Round Two, 01/16/08
- Round Three, 02/04/08
- Round Four, 03/04/08
- Round Five, 04/28/08

All original stakeholder comments that have been submitted to the CAISO are posted at: http://www.caiso.com/1f50/1f50ae5b32340.html

Other stakeholder efforts include:

- Conference Calls: December 20, 2007, January 24, 2008, February 7, and February 24, 2008.
- In-person Meetings: January 8, 2008, March 6, 2008 and April 11, 2008.
- CAISO responded in writing to stakeholder questions; IBAA "Q&A" can be found at http://www.caiso.com/1f50/1f50ae5b32340.html

A. Summary of Adopted Stakeholder Recommendations

The stakeholder process described above enabled the CAISO to receive numerous comments and concerns raised by stakeholders. While the CAISO was not able to accommodate all of the proposed alterations, in addition to specifically delaying its filing three times in response to requests by stakeholders, the CAISO incorporate a number of changes in its proposal directly in response to stakeholder input. In addition, directly in response to stakeholder requests, the CAISO agreed to include additional detail regarding its modeling and pricing approach and make a new filing at FERC under Section 205 of the Federal Power Act.

The details of the actual IBAA proposal are described more fully in the Transmittal Letter and the accompanying testimony submitted in support of this filing. Below is a summary of the modifications the CAISO made specifically in response to stakeholder concerns.

1. Opportunity to Reconfigure Congestion Revenue Rights in the Event that the CAISO Adopts a New IBAA or Modifies an Existing IBAA

After the CAISO released its December Discussion Papers discussing the alternative modeling and pricing proposals, stakeholders raised concerns regarding the incongruence and issues that might occur in the event that CRRs are released pursuant to a FNM with a different IBAA definition than the one that the CAISO ultimately uses in its operation of the CAISO Markets. (See Transmittal Letter, Section IV.A.9 at p. 22-25) In addition to using the FNM for scheduling power flows and determining locational energy prices in the core MRTU market systems, the CAISO uses the FNM in the allocation and auction of CRRs. Accuracy of the FNM in the CRR process is critical to the CAISO's ability to balance the competing objectives of releasing as many CRRs as possible to market participants, while minimizing the risk of CRR revenue shortfall that could occur if the CAISO collects insufficient congestion revenues from the Day-Ahead Market to cover CRR settlements fully on a monthly basis. (See Transmittal Letter, Section IV.A.9.b at p. 24) During the stakeholder process on the IBAA modeling and pricing approaches, participants raised the following two issues regarding how the adoption of IBAAs may affect the release and settlement of CRRs.

a. Impact of an IBAA change (either the creation of a new IBAA or the modification of an existing IBAA) on the future release of CRRs

The CAISO expects that IBAA changes will undergo extensive study and analysis before they are implemented in the FNM and the CAISO will strive to synchronize future IBAA changes with the annual CRR release process. (See Transmittal Letter, Section IV.A.9 at p. 22-25) In some instances there may be a need to implement an IBAA change mid-year because of a need for improved accuracy in the Day-Ahead and Real-Time Market congestion management processes. In response to this concern, the CAISO proposed to incorporate the IBAA change into the FNM for the first monthly CRR process in which the IBAA change will take effect, and will follow the proposed provisions described below for assessing and mitigating impacts on the previously-released Seasonal CRRs for the remainder of that year.

b. Impact of an IBAA change on the settlement of previously-released CRRs

Stakeholders raised a concern that in the event that an IBAA change occurs after CRRs are already released, a discrepancy may be created between the source or sink location of a previously-released CRR and the new source or sink that is adopted based on incorporating the IBAA transmission and pricing provisions into the FNM. (*See* Transmittal Letter at , Section IV.A.9.b at p. 24) Based on feedback from stakeholders and the CAISO's careful consideration, the CAISO proposed an approach that would allow the holder of a previously-released CRR whose source or sink is affected by the IBAA change to make a one-time election either to (a) modify the settlement of the CRR to be congruent to the revised IFM pricing associated with the IBAA change, or (b) retain the original source or sink specification of the CRR, subject to the requirement that affected CRR Holders make their elections prior to the start of the CAISO's process to release any new CRRs for the period when the IBAA change will be in effect. (*See* Transmittal Letter at, Section IV.A.9.a at p. 23).

With the adoption of the Single Hub approach as opposed to the Multiple Hub approach contemplated when the CAISO released CRRs through the annual CRR allocation and auction process conducted in 2007 for the release of 2008, stakeholders raised a concern that holders of such CRRs would be subject to the same incongruent situation described above. In response the CAISO proposed, consistent with the general policy described above, that a holder of such affected CRRs would be given an opportunity to make a one-time election, for each affected CRR they hold, either to retain the IBAA source and sink specification as originally awarded, or to reconfigure the affected CRR source or sink to match the revised pricing locations of the single-hub IBAA approach. These provisions would apply to (a) Seasonal CRRs that are in effect during the months of 2008 for which the MRTU markets are operating, (b) previously-allocated Seasonal CRRs that are eligible for PNP nomination, and (c) previously-released Long Term CRRs. *See* Proposed MRTU Tariff § 36.14.2.

2. Opportunity for Alternative Modeling and Pricing for Specific Schedules Pursuant to a Market Efficiency Enhancement Agreement

A number of entities internal and external to the CAISO Balancing Authority Area raised concerns that the IBAA undermines their existing investments on their systems and alleged that in some cases the IBAA proposal violates certain contracts that govern the operations of the California-Oregon Intertie. The CAISO evaluated the agreements and did not find that the IBAA proposal violated these existing agreements. After continued consultations the CAISO modified its IBAA proposal so that the CAISO has specific authority under the tariff to enter into Market Efficiency Enhancement Agreements ("MEEAs") that provide for alternative modeling and pricing approaches for specific parties provided that the CAISO is provided data it can use in its markets and verify submitted schedules and there is a demonstrable benefit provided by such arrangements. *See* Proposed MRTU Tariff § 27.5.3.2 and the definition of a Market Efficiency Enhancement Agreement in Appendix A to the MRTU Tariff. The CAISO believes that such arrangements can allow the CAISO to proceed with the default proposal and continue to pursue such alternative arrangements that would provide more favorable modeling and pricing to participants. On May 30, 2008, the CAISO provided such an alternative arrangement to the IBAA Entities that can be achieved through a MEEA (*See* Transmittal Letter, Section IV.F at pp. 38-40).

3. Increased Process For Adoption of new IBAA and Modification of Existing IBAA

Stakeholders requested that in the event that the CAISO adopt a new IBAA in the future or make modifications to the existing IBAA, the CAISO should provide an opportunity for stakeholder comment and input in these changes. In response to stakeholder concerns, the CAISO agreed to provide specific detail in its tariff that requires a stakeholder process in the event that the CAISO is also proposing a process for the adoption and implementation of additional IBAAs in the future (or a modification of then existing IBAAs). *See* Proposed MRTU Tariff § 27.5.3.2. The proposed process requires the ISO to seek collaboration and conduct a consultative process with the affected BAAs and ISO stakeholders. Specifically, the ISO is proposing to include in its Tariff provisions that, except under exigent circumstances, would require that the ISO follow a consultative process with the affected BAA and its stakeholders. *Id*.

V. SUMMARY TABLE OF IBAA DEVELOPMENT, CONSULTATION, AND STAKEHOLDER PROCESS

A. Timeline of IBAA Development, Consultation and Stakeholder Process

The following table illustrates the chain of relevant events in the CAISO's IBAA development, consultation, and stakeholder process leading to this filing:

IBAA Development, Consultation and Stakeholder Timeline

Date	Activity
May 1, 2002	CAISO files MD02 proposal
July 22, 2003	CAISO files amended MD02 proposal
February 9, 2006	MRTU Tariff language filed with FERC including § 27.5.3 regarding Embedded and Adjacent Control Areas (now IBAAs).
March 3, 2006	CAISO Meeting with SMUD to discuss data requests for MRTU.
July 31, 2006	CAISO publishes a draft BPM for Full Network Model indicating that the SMUD, Western, Modesto Irrigation District (MID), and Turlock Irrigation District (TID) are Adjacent Control Areas that may be included in the FULL NETWORK MODEL because they have transmission facilities that operate in parallel with the CAISO Control Area and are highly interconnected to the CAISO Control Area. *See* § 2.2.5 of July 31, 2006 BPM for the Full Network Model. The BPM can be found at (http://www.caiso.com/1841/1841c80437f00.pdf).
Sept 26, 2006	Commission issues Order Conditionally Accepting MRTU Tariff, sets Seams Technical Conference. ("We support the CAISO's commitment to include more information concerning adjacent and embedded control areas in the Full Network Model as soon as possible.") P 45.
December 14-15, 2006	Commission holds Technical Conference on Seams Issues related to the MRTU Market.
January 17, 2007	CAISO files post Technical Conference on Seams Issues comments.
January 19, 2007	CAISO updates and published new version of BPM for the Full Network Model.
January 26, 2007	MRTU Seams Issues Outreach with SMUD; included a brief

	discussion on data exchange needed for MRTU modeling. (*See* CAISO's April 30, 2007, First Quarter FERC Seams Report)
January-February 2007	CAISO meeting with various Balancing Authority Areas regarding need for detailed FNM and data exchange. (*See* CAISO's April 30, 2007, First Quarter FERC Seams Report)
February 22, 2007	CAISO meeting with SMUD to discuss stakeholder process issues and MRTU generally. (*See* CAISO's April 30, 2007, First Quarter FERC Seams Report)
April 19, 2007	CAISO updates and published new version of BPM for Full Network Model.
April 20, 2007	CAISO meeting with SMUD regarding data exchange (*See* CAISO's July 30, 2007, Second Quarter FERC Seams Report)
April 24, 2007	CAISO meeting with WAPA representatives on data exchange requirements under MRTU and need to model IBAAs. (*See* CAISO's July 30, 2007, Second Quarter FERC Seams Report)
May 16, 2007	CAISO meeting with SMUD to discuss operating practices of SMUD under the MRTU design and limitations for Embedded Control Areas.
June 5, 2007	Representatives of Western, SMUD, and the CAISO met to discuss the modeling and settlement treatment for Embedded/Adjacent Control Areas (ECAs/ACAs) under MRTU. The discussions focused on how the CAISO proposed to represent (in the MRTU-related network models and systems) the SMUD/Western control area and how the CAISO will establish related prices. (*See* CAISO's July 30, 2007, Second Quarter FERC Seams Report)
June 13, 2007	CAISO meeting with Western to continue dialogue on how MRTU will treat embedded control areas. (*See* CAISO's July 30, 2007, Second Quarter FERC Seams Report)
August 9, 2007	Meeting with Western, Redding, TID, SMUD and MID regarding data requirements for MRTU; discussed data needs and three options for pricing. (*See* CAISO's October 30, 2007, Third Quarter FERC Seams Report)
August 21, 2007	Meeting with Western, MID, TID, Redding and SMUD regarding pricing options for EBA/ACAs. (*See* CAISO's October 30, 2007, Second Quarter FERC Seams Report)
October 5, 2007	IBAA proposal distributed to IBAA entities.
November 14, 2007	Letter from IBAA entities to CAISO regarding CAISO proposal
December 6, 2007	Letter from CAISO to SMUD on IBAA Issues.

December 11, 2007	Meeting with SMUD, Turlock Irrigation District (TID), and Western Area Power Administration (Western) on IBAA issues.
December 14, 2007	Two whitepapers posted for stakeholder review: 1. *Modeling and Pricing IBAA Under the CAISO MRTU* (*see* http://www.caiso.com/1cb4/1cb4e1a154060.pdf); and 2. *MRTU Release 1 Implementation of Preferred IBAA Modeling and Pricing Options* (*see* http://www.caiso.com/1cb4/1cb4e0984a670.pdf)
December 20, 2007	Stakeholder conference call to update on modeling and pricing of IBAAs
January 6, 2008	Stakeholder comments received on December 20th conference call.
January 8, 2008	Stakeholder meeting on IBAA issues.
January 16, 2008	Stakeholder comments received on January 8, 2008 stakeholder meeting.
January 22, 2008	Tariff language and related presentation posted for stakeholder review.
January 24, 2008	Stakeholder conference call regarding IBAA issues and tariff language.
February 4, 2008	Stakeholder comments received on proposed tariff language and stakeholder conference call.
February 5, 2008	CAISO posts responses to stakeholder questions
February 7, 2008	Stakeholder conference call on proposed tariff and IBAA filing
	Stakeholder written comments on tariff language
February 15, 2008	CAISO posts responses to stakeholder questions
February 21, 2008	Whitepaper on CRR-related issues
February 25, 2008	Stakeholder conference call on IBAA issues
February 29, 2008	Stakeholder comments on CRR whitepaper
March 4, 2008	CAISO posts responses to stakeholder questions
March 6, 2008	Stakeholder meeting
April 3, 2008	CAISO and stakeholder meeting with the Transmission Agency of Northern California ("TANC").
April 9, 2009	Technical Meeting on IBAA
April 11, 2008	Joint stakeholder/MSC meeting on IBAA

April 14, 2008	CAISO posts responses to stakeholder questions
April 16, 2008	CAISO posts responses to stakeholder questions
April 18, 2008	Draft final proposal posted describing the move from a multi-hub approach to a single hub approach per stakeholder comments and the concerns of the CAISO’s Market Surveillance Committee”(MSC”)
April 25, 2008	Comments on CAISO proposal
May 2, 2008	MSC opinion on IBAA proposal posted
May 7, 2008	Conference call to discuss MSC opinion
May 8, 2008	Alternative IBAA proposal submitted by IBAA entities
May 9, 2008	Post revised draft tariff language
May 14, 2008	Post Documents for Board of Governors related to IBAA proposal
May 21-22, 2008	IBAA proposal discussed and approved by Board of Governors
May 30, 2008	Conference call on IBAA tariff language
May 30, 2008	CAISO Response to IBAA entities proposal

Attachment F

Exhibit No. ISO-1 – Panel Testimony of Mark Rothleder and Dr. James Price

Docket No. ER08-___-000 **Exhibit No. ISO-1**

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER08-___-000**

PREPARED DIRECT TESTIMONY
OF
MARK ROTHLEDER
AND
JAMES E. PRICE

June 17, 2008

.

EXECUTIVE SUMMARY

This is the testimony of Mr. Mark Rothleder, and Dr. James E. Price (the "Panelists") of the California Independent System Operator Corporation ("CAISO"). Mr. Rothleder is the Principal Market Developer for the CAISO and Dr. Price is the Lead Engineering Specialist in the Department of Market and Product Development. The purpose of their testimony is to provide: (1) an explanation of the objectives of the Integrated Balancing Authority Area ("IBAA") proposal; (2) a description of the IBAA proposal; (3) identification of the specific criteria proposed by the CAISO for identifying IBAAs and application of that criteria to the Sacramento Municipal Utility District ("SMUD") and Turlock Irrigation District ("TID") BAAs; (4) the reasons this filing is necessary at this time; (5) the alternatives the CAISO considered; and (6) a discussion of specific issues related to the proposal including: (a) the effect on the accuracy of the full network model ("FNM"); (b) the reason for the selection of the Captain Jack and SMUD Hub pricing points; and (c) the treatment of losses. In addition, they explain the process for development of Market Efficiency Enhancement Agreements ("MEEA"), which would enable the CAISO to provide alternative pricing if the CAISO is able to receive additional verifiable data and the alternative arrangement provides market efficiency enhancements. The Panelists also provide information on CAISO's continued efforts to work with certain parties such as the Transmission Agency of Northern California ("TANC") and the TANC members on alternative pricing arrangements to address concerns raised by the parties during the stakeholder process.

They also explain why the IBAA proposal is consistent with the CAISO's treatment of, and will not infringe upon, Transmission Ownership Rights ("TORs") and Existing Transmission Contract rights ("ETCs").

The Panelists state that the objective of the IBAA proposal is to appropriately model and price interchange transactions in a manner consistent with the use of location-based marginal prices ("LMPs") under MRTU and that this objective responds to the Commission's directives in its earlier orders requiring that the CAISO address the fundamental flaws under the CAISO's zonal congestion management approach. They note that with LMP, determinations regarding the location of resources external to the CAISO Controlled Grid used to implement interchange transactions are as important to congestion management and pricing over the internal CAISO system as the specifications the CAISO makes for resources internal to the CAISO Controlled Grid in its FNM.

The Panelists explain that the IBAA proposal improves the accuracy of LMPs by reflecting the impact of external flows on the CAISO system by approximating the location of the external resources used to support scheduled interchange. In addition, the IBAA proposal provides a solution to the issues identified by Dr. Harvey, the Market Surveillance Committee ("MSC"), and the CAISO Department of Market Monitoring ("DMM") with regards to the adverse pricing incentives created when participants have the opportunity to select multiple interties to schedule their interchange schedules in a manner that is not consistent with the actual use of the interconnected grid. Inaccurate modeling and not accounting for these flows could result in ignoring and not resolving congestion in the Day-Ahead Market that would ultimately occur in Real-Time, or conversely, may result in unit commitment and dispatch decisions in the Day-Ahead Market due to congestion in the Day-Ahead Market that are ultimately infeasible in Real-Time because that congestion does not occur ("phantom congestion") in Real-Time. Such infeasibilities could result in higher re-dispatch costs but also could result in reliability problems if operational options to resolve such congestion no longer exist in Real-Time.

For these reasons, in order to accurately and reliably manage congestion on the CAISO Controlled Grid under MRTU using an LMP-based congestion management system, the CAISO must accurately model in its FNM the power flows or network effects on the CAISO's BAA arising from power flows on and between such integrated external areas and the CAISO, as well as provide prices that do not provide the incentive to inappropriately schedule at the interties with the external integrated BAAs. The methodology proposed in this filing enables the CAISO to model the flows in the IBAA in a manner that, absent the provision of more detailed information, reasonably and appropriately reflects where the power is actually coming from within the IBAA so that the power flow impacts of scheduled interchange transactions with the IBAA on the CAISO Controlled Grid can be appropriately captured in the CAISO's day-ahead schedules, hour-ahead schedules, dispatch, and related LMPs.

The Panelists describe the "single hub" proposal. The CAISO is proposing to model the SMUD BAA and the TID BAA together as a single "Integrated" Balancing Authority Area or "IBAA". Similarly, with respect to pricing, the CAISO proposes to establish a "single-hub" default pricing rule for pricing intertie transactions between the CAISO and the IBAA. In the absence of a MEEA, the CAISO would determine the supporting injection and withdrawal locations to allow the impact of the associated Intertie Scheduling Point Schedules on the CAISO Controlled Grid to be reflected in the CAISO market processes as accurately as possible given the information available to the CAISO. All imports to the CAISO from the SMUD-TID IBAA (excluding those associated with a pseudo-tie) would be priced based on the LMPs calculated at the Captain Jack System Resource pricing point. All exports from the CAISO to the SMUD and TID IBAA would be priced at the LMP calculated at the SMUD Aggregated System Resource pricing point (SMUD Hub). The CAISO intends to monitor and if necessary modify the single pricing hub by adding or subtracting locations or by modifying the distribution factors used to distribute scheduled transactions.

The IBAA proposal also allows for alternative pricing arrangements if an entity agrees to provide the CAISO with additional information that allows the CASIO to verify the location and operation of the resources within the IBAA that are actually used to implement a scheduled interchange transaction. The alternative arrangement could be with an individual generator, a group of generators, dispatchable load, load serving entities, or an entire BAA or a group of BAAs. The key notion, as emphasized by the Panelists, is that the entity with access to the necessary data provides it to the CAISO and thereby enables the CAISO to have the necessary visibility regarding the location and operation of the resources within the IBAA and can verify the scheduled resources were in fact dispatched to support the submitted schedules. This arrangement resolves the concern about inappropriate scheduling and pricing incentives by ensuring that the location of injection used to implement the interchange with the CAISO is known and verifiable.

The Panelists explain that the CAISO identified the following six criteria to assess whether or not external BAAs should be incorporated into the IBAA proposal: (1) the number of Intertie Scheduling Points between the CAISO and the relevant BAA and the distance between these points; (2) the extent to which significant transmission facilities within a BAA operate in parallel to major parts of the CAISO Controlled Grid; (3) the frequency and magnitude of unscheduled flows at the applicable Intertie Scheduling Points; (4) the number of hours where the actual direction of flows was reversed from the scheduled directions; (5) the availability of information to the CAISO for modeling purposes; and (6) the estimated improvement to the CAISO's power flow modeling and congestion management processes to be achieved through more accurate modeling of the BAA.

They then evaluate how the combined SMUD and TID IBAA satisfy these criteria. The combined SMUD BAA and TID BAA has twelve (12) interties (10-SMUD and 2-TID) with the CAISO and have an interconnection with each other (such that interchange transactions can be scheduled on a contract path between SMUD and TID without scheduling through the CAISO). The SMUD BAA parallels a major portion of the CAISO Controlled Grid for over 300 miles and that experience has shown that significant portions of the CAISO lower-voltage transmission system that parallels the SMUD BAA transmission is susceptible to congestion. Furthermore, analysis of the unscheduled flow between the CAISO and the SMUD-TID BAAs confirms that the frequency and magnitude of unscheduled flows at the Intertie Scheduling Points between the CAISO and the SMUD/TID BAAs are frequent and unpredictable. With respect to the number of hours where actual direction of flows is reversed from scheduled directions, the CAISO found that for two of the interties the direction of the flows reversed during 67 and 73 percent of the hours. On four of the interties, the flows were reversed from 33 to 45 percent of the hours. These systems were once part of the CAISO BAA and therefore, the CAISO has more extensive data available to it to enable it to determine the reasonableness of the assumptions it makes regarding the location of resources in these BAAs and the IBAA proposal for the SMUD-TID IBAA provides important improvements to the CAISO's power flow modeling and congestion management processes, which will be achieved through better modeling of resources in the SMUD-TID BAA.

The Panel explains that the CAISO is submitting this filing at this time for three primary reasons. First, the CAISO and stakeholders are making tremendous efforts to finalize system development and properly test the MRTU systems and applications. Filing now is necessary to permit time for Commission consideration of the proposal, testing by market participants, and implementation at the start of MRTU. Second, it is critical to eliminate the inappropriate pricing incentives that could result in manipulation of otherwise flawed market rules and other market inefficiencies that would exist in the absence of this proposal. Third, from a modeling perspective, it is critical that the IBAA proposal be implemented at the start of MRTU to enhance the accuracy and cost-effectiveness of the CAISO's congestion management solutions for the affected Intertie Scheduling Points.

The Panelists report that over the past several years, the CAISO has considered a number of options, which the Panelists also explain, in its attempt to determine how best to treat external control areas in MRTU: (1) an original concept of a "closed loop" regional design, which would have required full detailed modeling of the external WECC regional system and exchange of information, in order to provide an accurate model; (2) the "full physical model" (3) the "" approach; and (4) the currently proposed "single hub" approach. While the CAISO continues to believe that its original proposal is the most accurate approach to modeling flows on, and interchange transactions with, external BAAs, based on their representations, the CAISO concluded it was unlikely that the CAISO and the SMUD-TID BAA could agree on sharing the necessary data to make this approach work and concluded that continued pursuit of this approach would create too great a risk to the MRTU project. In the spring 2007, the CAISO began to investigate other alternative approaches. After evaluating several approaches, the CAISO advocated what it characterized as a "sub-hub" IBAA modeling and pricing approach.

The Panelist explain that the CAISO modified its proposal to address concerns raised by the DMMthe MSC, and its expert consultant Dr. Scott Harvey about relying on potentially unverifiable representations as to the actual location of System Resources.

The Panelists explain that the CAISO selected the Captain Jack System Resource and SMUD hub System Resource pricing points as the default pricing points for, respectively, all imports to and exports from the CAISO system from the SMUD and TID IBAA in order to eliminate the "circular scheduling" concern. The CAISO selected a low priced location as the default location for pricing all imports (sales to the CAISO) and a high priced location for the default location for pricing all exports (purchases from the CAISO), the CAISO has eliminated the price incentive to simultaneously buy at low priced locations such as Captain Jack and sell at high priced locations such as the SMUD hub. In addition, by selecting the Captain Jack System

Resource pricing point as the default location for all imports to the CAISO, the CAISO has reduced the likelihood that Market Participants will take advantage of potential artificial price differences between the Malin ISP (Malin is the ISP between the CAISO and the Bonneville Power Administration) and an alternative and higher default pricing point for imports to the CAISO from the SMUD and TID IBAA. The CAISO believes that the Captain Jack and SMUD hub System Resource pricing points are, in the absence of more detailed information, reasonable approximations of the marginal resources likely to support, respectively, imports and exports to the CAISO from the SMUD and TID IBAA. Moreover, the CAISO's proposal and the location of the pricing point create the proper incentive. If the external entities – the parties with the data – are willing to provide it to the CAISO to verify the location and operation of the resources supporting scheduled interchange, then the CAISO has offered to modify its approach to utilize the more detailed modeling and pricing information. It is only in the absence of the agreement of those with the data to provide it that the CAISO must act in this prudent and conservative manner.

The Panelists also explain why the CAISO did not select Tracy as the pricing point. The Tracy Intertie Scheduling Point is unique in that it is a high-capacity intertie in the middle of the CAISO Controlled Grid at which no physical generation is located. Thus, while Tracy serves multiple alterative sources and sinks that are not electrically near Tracy, it would be inaccurate to treat Tracy as a "source" point or proxy bus under the CAISO's IBAA proposal. While Intertie locations with other BAAs do not have physical generation, similar to Tracy, Tracy is unique with respect to its network location and capacity in that the Node is located in the middle of the

CAISO Controlled Grid as opposed to being located on the perimeter of the CAISO Controlled Grid. Having inaccurate assumptions about the source of transactions scheduled at Tracy can lead to discrepancies between scheduled and actual flows and increase the CAISO's cost of resolving such discrepancies. It is inappropriate to have a continued expectation of market outcomes that are based on a less accurate modeling of external systems and interchange transactions.

With regard to transmission losses, the Panelists explain whatmeasures will be taken to exclude the marginal transmission losses within the IBAA from affecting the prices within the IBAA and the CAISO. Therefore, the LMPs established on the CAISO Controlled Grid will not be prices used for settlement of the IBAA are not affected by congestion or losses within the IBAA and only represent the marginal effect of losses and congestion within the CAISO Controlled Grid. The CAISO proposes to schedule and dispatch Bids for IBAA System Resources as if there were no losses within the IBAA network, and to use the scheduled or dispatched MW as the basis for expected net interchange between the CAISO BAA and the IBAA. Although transmission losses within IBAAs, and on interties between IBAAs, will be fully accounted for in power flow calculations, their marginal impact will be ignored in the loss penalty factor calculations for setting the CAISO's LMPs. Therefore, the marginal impact of transmission losses will be ignored in the LMP calculations by zeroing the partial derivative contributions to the loss penalty factors from network branches within the IBAA networks and from the IBAA interties. This will only affect marginal loss rates and does not alter in any way the transmission losses within the IBAA networks, which are accurately represented in the optimal Schedule and Dispatch by the full AC power flow solution in the market optimization.

The Panelists describe how the IBAA proposal does not impact or change any of the established WECC interchange scheduling or e-tagging rules. Existing scheduling and checkout processes will be maintained using existing Intertie Scheduling Points and established Scheduling Limits. Importantly, the IBAA proposal does not limit an entity's rights to utilize or market their transmission that is not capacity located part outside of the CAISO Controlled Grid. Nor does the CAISO's IBAA proposal in any way modify the CAISO's proposed treatment of Transmission Ownership Rights (TORs) under MRTU. In no case does the CAISO establish prices for the use of facilities points outside of the CAISO Controlled Grid. Rather, the CAISO is determining the price (value to the CAISO for purposes of managing congestion and losses on the CAISO Controlled Grid) for those scheduled transactions based on the price of the resources identified as supporting the transaction. While the identified resources may reside outside of the CAISO Controlled Grid (*e.g.*, are System Resources, as defined under the CAISO Tariff), the price or value of that System Resource will be determined by a combination of its associated bid price and its location on the larger CAISO-IBAA network (*i.e.*, where it is injecting power) for purposes of managing congestion and calculating losses only on the CAISO Controlled Grid.

External entities that operate under the traditional "contract path" paradigm have raised concerns regarding the CAISO's need to determine the point of injection (source) of a transaction – especially when that point is outside of the CAISO Controlled Grid - for purposes of assessing the congestion impact of such an injection on the CAISO Controlled Grid.

However, the Panelists emphasize that the CAISO is only proposing to model and price transactions scheduled to the Intertie Scheduling Points between the CAISO and the IBAA in a manner that reflects the value of such scheduled transaction (import or export) for purposes of managing congestion on the CAISO Controlled Grid. Under the CAISO's IBAA proposal, the CAISO is mapping scheduled import interchange transactions back to specified System Resources (Captain Jack) to approximate the location of the resource supporting the scheduled interchange transaction and determining the impact of an injection at that location for determining the impact of such an injection on flows on the CAISO Controlled Grid. While the CAISO is establishing a price reflective of the value of such injections at such pricing points (Captain Jack System Resource), the CAISO is only doing so to price use of the CAISO Controlled Grid. Rather than diminishing rights, the CAISO has created new markets enhancing the demand for and value of those facilities.

The Panelists also explain that the IBAA proposal does not modify the ability for an ETC or TOR rights holder right to schedule a transaction at a specific Intertie Scheduling Point, if the ETC or TOR rights holders is entitled to do so under its ETC or TOR. However, in the event that an IBAA Hub is established that affects the price and related settlement of schedules at a specific Intertie Scheduling Point based on the hub pricing, the ETC and TOR perfect hedge settlement accepted as part of the CAISO's MRTU Tariff would be based on the congestion component of the LMP consistent with the IBAA hub pricing established for the specific Intertie Scheduling Point.

The Panelists state that ultimately, the CAISO desires to model each of its interconnections with other Balancing Authority Areas in a closed loop methodology or highly integrated manner. However, maintaining accuracy in the CAISO's calculations of flows within the CAISO BAA when using a regional-wide closed loop model will require that the external Balancing Authority Areas would share with the CAISO detailed information about the dispatch of resources (generation and loads) internal to each Balancing Authority Area with the CAISO. Currently, there has been and will likely be a great deal of reluctance to support the level of data exchange that is needed to implement a closed loop model in the West. While the ultimate goal of closed loop modeling is not achievable in the near term, this should not deter the CAISO from making improvements where sufficient data is available. The CAISO does support and participate in WECC as a forum for further consideration regional congestion management approach.

The Panelists discuss the "Proposed Alternative to the CAISO's April 18th IBAA Proposal" provided by the IBAA Entities, which consist of the SMUD - Western Area Power Administration Balancing Authority, TID Balancing Authority, TANC and TANC members (collectively, "IBAA Entities"). While the CAISO appreciated the parties' efforts to develop additional information that the CAISO could utilize in its modeling, the CAISO had significant concerns regarding the IBAA Entities' modeling and pricing proposal. First, the CAISO is unclear how the additional data proposed to be exchanged or made available would enhance the CAISO's modeling of the IBAAs. Second, under the IBAA Entities' proposal, the CAISO would not have visibility regarding the location of the resources within the IBAA used to implement interchange transactions; rather, each transaction would be modeled at the boundary (i.e., assuming the resources are located at or near the ISPs themselves). Third, the CAISO is not convinced the monitoring and information exchange process would be sufficient to address the CAISO's previously articulated pricing concerns.

The Panelists summarize a counter-proposal the CAISO made that attempts to address certain of the issues previously raised by the IBAA Entities. The CAISO proposed to provide all TANC members that use the COTP to serve load embedded within the CAISO BAA for the amount of the load served, a marginal losses exemption for the prices calculated using the System Resource located at the Captain Jack Substation, but instead settle such transactions based using calculated marginal loss component of the LMP at the Tracy 500 kV bus. This would essentially mean that the marginal losses will be calculated in fashion assuming that the source of the as if the import were located at or near the Tracy 500 kV ISP or bus. The sink of the transaction would be the delivery point on the CAISO transmission system. Important, however, is the fact that this exemption would only be granted in return for the provision of additional data by the TANC member IBAA Entities, which the CAISO would have to be able to use to enhance its modeling. In addition, the conceptual proposal would allow the CAISO to incorporate the COTP line into the CAISO's Marginal Loss calculation to more fully collect Marginal Losses associated with schedules using the CAISO Controlled Grid. The default treatment in modeling an IBAA, which is to include only the transmission that is within the CAISO in the calculation of the marginal loss component of LMPs, is premised on the resulting charges for marginal losses being applicable from the physical sources of Schedules to their physical sinks. When the marginal loss charges for COTP schedules are based on a contractual delivery to Tracy instead of the default source at Captain Jack, the default calculation for the marginal loss component of LMPs would produce an under collection of marginal loss revenues, which would need to be recovered from the remaining CAISO market participants. Incorporating the COTP line in the CAISO's Marginal Loss calculation will partially offset this under collection by more fully accounting for the losses between Captain Jack System Resource and the CAISO BAA. At the time of this filing, the parties have not yet had an opportunity to meet and discuss this counter proposal. The Panelists also explain that it is appropriate to not allow for the application of the methodology for calculation loss exemption as described above during any period in which the IBAA entity is simultaneously using COTP to import power to serve load with the CAISO Controlled Grid and scheduling exports from the CAISO transmission system, at Tracy or any other scheduling point.

The CAISO believes that such a condition is warranted because TANC and TANC members have supported their need for an alternative pricing arrangement on their use of the COTP to serve their load both on and off the CAISO system. Therefore, a reasonable condition of the alternative pricing arrangement is that while using the COTP and the CAISO Controlled Grid to serve their load and receiving the alternative pricing under the agreement, they should not be simultaneously using the CAISO Controlled Grid to sell to other entities. The CAISO recognizes that TANC members may own generation within the CAISO BAA that is used to serve their own loads outside the CAISO BAA, which does not constitute sales to other entities.

The CAISO intends to develop appropriate provisions to accommodate such use of generation owned by TANC members to serve their own loads.

In addition, the Panelists explain that the CAISO already provides mechanisms by which IBAA Entities that utilize the COTP to serve load on the CAISO system can substantially hedge their congestion cost exposure. For example, in instances where IBAA Entities serve load within the CAISO BAA through ETCs, the CAISO exempts the ETC Self-Schedules from congestion charges through the established "perfect hedge" mechanism. In other instances where IBAA Entities serve load within the CAISO BAA, the CAISO provides CRRs. Under the CAISO's market design (including its IBAA proposal), IBAA Entities will be able to request CRRs sourced at Captain Jack and sunk to load on the CAISO system, thus providing a hedge against potential transmission congestion costs on the CAISO system (including both the 500kV and underlying 230kV systems referred to above). Therefore, the CAISO believes that, when combined with the mechanisms (ETCs and CRRs) already available, the proposal outlined above substantially addresses the major cost concerns (losses) expressed by IBAA Entities with respect to their use of their rights on the COTP to serve load on the CAISO system.

In summary, the Panelists conclude that it is likely that there will be significant adverse effects on the CAISO's ability to manage congestion at the interties under MRTU if the CAISO were to continue to model the SMUD and TID BAAs in a radial manner as it does today under the current zonal market. They believe that that the adoption of the SMUD and TID IBAA, the proposed modeling and pricing mechanisms and other associated IBAA changes will best support the following important objectives of MRTU: (1) feasible forward market schedules;

(2) more effective congestion management solutions that will reduce uplift costs and other market inefficiencies; and, most importantly, (3) eliminate inappropriate scheduling incentives and pricing signals likely to result if the IBAA modeling and pricing mechanisms are not aligned. It is important to understand that it is the combination number of interconnections, the distances between the different interconnections and the fact that some of the interconnections are not related to any specific resources that creates the scheduling and pricing inefficiencies and potential for reliability problems related to large differences between modeled flows and actual flows.

I. INTRODUCTION & OVERVIEW

A. EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Our names are Mark Rothleder and James E. Price. We are both employed by the California Independent System Operator Corporation ("CAISO") located at 151 Blue Ravine Road, Folsom, California 95630.

Q. MR. ROTHLEDER, WHAT ARE YOUR RESPONSIBILITIES AT THE CAISO?

A. I am the Principle Market Developer for the CAISO and, currently, I am in the lead role in the implementation of market rules and software modifications related to the CAISO's Market Redesign and Technology Upgrade ("MRTU"). Since joining the CAISO over ten years ago, I have worked extensively on implementing and integrating the approved market rules for California's competitive Energy and Ancillary Services markets and the rules for Congestion Management, Real-Time Economic Dispatch, and Real-Time Market Mitigation into the operations of the CAISO BAA ("BAA"). I have also held the position of Director of Market Operations**.**

Q. MR. ROTHLEDER, PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a registered Professional Electrical Engineer in the State of California. I hold a B.S. degree in Electrical Engineering from the California State University, Sacramento. I have taken post-graduate coursework in Power System Engineering from Santa Clara University and earned an M.S. in Information Systems from the University of Phoenix. I have co-authored technical papers on aspects of the California market design in professional journals and have frequently presented to industry forums. Prior to joining the CAISO in 1997, I worked for eight years in the Electric Transmission Department of Pacific Gas & Electric Company, where my responsibilities included Operations Engineering, Transmission Planning and Substation Design.

Q. MR. ROTHLEDER, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. In Docket No. EL00-95-045, I testified to the process by which the CAISO calculated incremental heat rates for gas-fired Generating Units associated with Generators that are subject to price mitigation in the CAISO's markets pursuant to the Commission's Market Mitigation Orders. In Docket No. ER06-615, I explained the CAISO's role in ensuring resource adequacy.

Q. DR. PRICE, PLEASE DESCRIBE YOUR RESPONSIBILITIES AT THE CAISO.

A. I am employed by the CAISO as Lead Engineering Specialist in the Department of Market and Product Development. In that capacity, I am responsible for design, analysis, and policy development for a wide variety of market features in the markets that are administered by the CAISO. Among my responsibilities in Market and Product Development have been guiding policy aspects and developing market-related details of the CAISO's Full Network Model ("FNM"), performing simulation studies of Locational Margianal Price ("LMP") market results in California (results of which have been published as LMP Studies 2, 3A, 3B, and 3C), performing analytical testing and tuning of the MRTU market software, designing enhancements in the CAISO's demand response programs for MRTU and subsequent phases of market enhancements, analyzing financial impacts on Load Serving Entities of test allocations of Congestion Revenue Rights ("CRRs"), designing the mechanisms for transfer of CRRs as load migrates between retail service providers, and contributing to other aspects of market development. In addition to these responsibilities, I provide technical support for other CAISO operations.

Q. DR. PRICE, PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received my Bachelor of Science degree from the California Institute of Technology, majoring in Engineering and Applied Science, and my Master of Science and Doctor of Philosophy degrees from Stanford University, where I studied Environmental Engineering and Infrastructure Planning and Management in the Department of Civil Engineering. My education included economics and social science in addition to public works planning.

Q. DR. PRICE, PLEASE DESCRIBE YOUR PREVIOUS WORK EXPERIENCE.

A. I was an engineering associate for the Los Angeles County Sanitation Districts in 1975, performing economic and social impact assessments of a 25-year master plan. I was employed by the California Public Utilities Commission ("CPUC") from 1978 to 1981, as a Utilities Engineer and Research Analyst (Economics), working in numerous aspects of applications for nuclear, coal, and hydroelectric power plants. From 1981 to 1984, I was a Research Program Specialist (Economics) in the Office of Economic Policy, Planning, and Research, part of the California Department of Economic and Business Development, performing research on industrial trends, natural resources, energy, benefit/cost analysis, and fiscal impacts.

In 1984, I returned to the CPUC as a Regulatory Program Specialist. I have testified before the CPUC on behalf of the Office of Ratepayer Advocates ("ORA"), which is an independent division of the CPUC staff that represents the interests of ratepayers in proceedings before the CPUC. This work concerned both policy and technical aspects of electric and gas revenue allocation and rate design issues affecting Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), Southern California Gas Company, San Diego Gas and Electric Company ("SDG&E"), PacifiCorp, Sierra Pacific Power Company, and Bear Valley Electric District. I served as ORA's project manager in a number of these rate proceedings. I became involved in the electric industry restructuring efforts through my employment with the CPUC. I represented ORA in both working groups that recommended procedures for implementing retail electric competition and stakeholder processes that led to the formulation of the CAISO and then to the refinement of the CAISO's markets. I then joined the CAISO as Market

Planning Engineer in Market Operations, in May 2000. While in the Market Operations department, I was responsible for evaluating and planning programs that provide competitive conditions in markets that are administered by the CAISO, and for coordinating with and providing technical support to other CAISO departments.

Q. DR. PRICE, HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. I have appeared as a witness before the CPUC in a number of proceedings, as described above. I also submitted testimony in FERC Docket No. ER01-313 involving the unbundling of the CAISO's Grid Management Charge. My testimony developed estimates of billing determinants for the portion of Control Area Gross Load that is represented by Load served by on-site generation, for example, by Qualifying Facilities.

Q. AS YOU TESTIFY, WILL YOU BE USING ANY SPECIALIZED TERMS?

A. Yes. We will use capitalized terms as defined in the Master Definitions, Appendix A of the CAISO Tariff.

B. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of our testimony is to support the CAISO's application to implement its Integrated Balancing Authority Area ("IBAA") proposal. In particular, we will provide:

(1) an explanation of the objectives of the IBAA proposal; (2) a description of the IBAA proposal; (3) an explanation of the need for the IBAA proposal, which includes an explanation of the effect of the IBAA proposal on the accuracy of the full network model ("FNM"); (4) identification of the specific criteria proposed by the CAISO for identifying IBAAs and application of that criteria to the Sacramento Municipal Utility District ("SMUD") and Turlock Irrigation District ("TID") BAAs; (5) the reasons this filing is necessary at this time and why the proposed IBAA approach should be adopted for implementation at the start of MRTU; (6) the evolution of the IBAA proposal and the alternatives the CAISO considered in its development; and (7) a discussion of some specific issues related to the proposal. These are: (a) the reason for the selection of the Captain Jack and SMUD Hub pricing points based on the single hub modeling and pricing approach; and (b) the treatment of losses for transactions over the CAISO Controlled Grid under the proposal.

In addition, we explain what the the IBAA proposal "does not do" and explain why the IBAA proposal is consistent with the CAISO's treatment of, and will not infringe upon, Transmission Ownership Rights ("TORs")[1] or Existing Rights (the rights of holders of existing transmission agreements protected by the "perfect hedge" accepted in Docket

[1] The ownership or joint ownership right to transmission facilities within the CAISO Control Area of a Non-Participating TO that has not executed the Transmission Control Agreement, which transmission facilities are not incorporated into the CAISO Controlled Grid.

No. ER06-615). Further, we explain why the COTP, due the fact it is not within the CAISO Control Area, is not a TOR by definition and therefore cannot be afforded the same treatment as are TORs under the CAISO tariff.

Finally, we explain the process for development of Market Efficiency Enhancement Agreements ("MEEA") and how the CAISO is continuing to work with certain parties such as Transmission Agency of Northern California ("TANC") and other IBAA Entities on alternative pricing arrangements to address concerns raised by the parties.[2] We provide an explanation of why the proposal provided by the IBAA Entities does not meet the objectives of the CAISO's IBAA proposal.

II. THE IBAA PROPOSAL

Q. WHAT ARE THE OBJECTIVES OF THE CAISO'S IBAA PROPOSAL?

A. The objective of the IBAA proposal is to appropriately model and price interchange transactions (*i.e.*, imports to, and exports from, the CAISO BAA using the CAISO Controlled Grid) in a manner consistent with the use of LMPs under MRTU.

---

2 TANC is a joint power agency and is composed of the California cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, and Ukiah; the Plumas-Sierra Rural Electric Cooperative; SMUD; the Modesto Irrigation District ("MID"), and TID. The transmission owners within the proposed IBAA include, in addition to SMUD and TID, the transmission facilities of: (a) the Western Area Power Administration – Sierra Nevada Region ("WAPA"); (b) MID; (c) the City of Redding ("Redding"); (d) the City of Roseville ("Roseville"); and (e) participants in the California Oregon Transmission Project ("COTP"). The participants in the COTP are Pacific Gas & Electric Company ("PG&E"), WAPA, TANC, Carmichael Water District, Redding, the California City of Vernon ("Vernon"), and the San Juan Suburban Water District. The term "IBAA entities" is a collective reference to the transmission owners in the SMUD and TID BAAs and the COTP participants except PG&E (*i.e.*, includes all the members of TANC) ("IBAA Entities").

Q. WHAT MODELING OBJECTIVES DOES THE IBAA PROPOSAL ADDRESS?

A. One of the fundamental objectives of MRTU and the implementation of LMP-based markets generally is to ensure feasible forward-market schedules and consistency between schedules and prices. This objective responds to the Commission's directives in its earlier orders requiring that the CAISO address the fundamental flaws under the CAISO's zonal congestion management approach. As stated by Dr. Harvey in his testimony, under an LMP-based congestion management and pricing system, the location of resources is important for the purposes of determining schedules, dispatch, and LMPs at the boundary of the system as it is for determining schedules, dispatch, and LMPs for internal locations. (Exhibit No. ISO-3 at 12). Therefore, the determinations one makes regarding the location of resources external to the CAISO Controlled Grid used to implement interchange transactions is as important to congestion management and pricing over the internal CAISO system as the specifications the CAISO makes for resources internal to the CAISO Controlled Grid in its FNM. In an interconnected grid, both transactions internal to the CAISO Controlled Grid and interchange transactions affect the flows on the CAISO Controlled Grid, and therefore affect the LMPs resulting from the models and tools used to manage congestion on the CAISO Controlled Grid.

Q. HOW DOES THE IBAA PROPOSAL ENHANCE THE MODELING OBJECTIVES?

A. Clearly, the CAISO has more visibility and knowledge of the location and operation of the resources internal to its system than it does of the location and operation of the external resources used to implement import and export transactions with the CAISO, which are not under its control. Except in circumstances where the CAISO has implemented a pseudo-tie arrangement (which involves specific agreement between an external generator, external BAA, and the CAISO) the CAISO does not dispatch nor has sufficient visibility of the external resources used to implement interchange transactions. As explained further below and in Dr. Harvey's testimony, the default modeling and pricing provisions in the IBAA proposal ensure that, in the absence of specific information regarding the location and dispatch of resources within the IBAA used to implement interchange transactions, the CAISO can implement its LMP-based market in a manner that will produce more accurate congestion management results by improving the representation of the impact on flows on the CAISO Controlled Grid of the external resources used to implement interchange transactions in the CAISO's FNM. (Exhibit No. ISO-3 at 13, 16, and 18-20).

Q. WHAT PRICING OBJECTIVES DOES THE PROPOSAL ADDRESS?

A. First, it is important to understand that modeling affects pricing. Therefore, the IBAA proposal improves the accuracy of LMPs on the CAISO system just by including a representation of the IBAA transmission systems in the CAISO's FNM and thereby reflecting the impact of external flows on the CAISO system. In addition, the IBAA proposal also approximates the location of the external resources used to support scheduled interchange. However, the IBAA proposal goes further and provides a solution to the issues identified by Dr. Harvey, the Market Surveillance Committee ("MSC"), and the CAISO Department of Market Monitoring ("DMM") with regards to the adverse pricing incentives created when participants have the opportunity to select from multiple interties to schedule their interchange schedules in a manner that is not consistent with the actual use of the interconnected grid. (*See* Exhibit ISO No. 2 at 8-11 and Exhibit ISO No. 3 at 18-19). As explained by Dr. Harvey and Dr. Hildebrandt, Market Participants are likely to schedule their interchange transactions at the locations most advantageous to their business interest (*i.e*., sell to the CAISO – import – at high-priced locations and buy from the CAISO – export – at low-priced locations) as opposed to the location that best reflects the true location of the actual source of the power supporting the scheduled interchange transaction with the CAISO. (*See* Exhibit ISO No. 2 at 8-9 and Exhibit ISO No. 3 at 18-20). Such inefficient and inappropriate pricing incentives would create a money machine that would adversely impact both reliability and result in higher costs to internal load. (*See* Exhibit ISO No. 2 at 9-10 and Exhibit ISO No. 3 at 32-37).

Q. PLEASE DESCRIBE THE ROLE OF THE FULL NETWORK MODEL.

A. The FNM is a detailed mathematical representation of the physical transmission system operated by the CAISO and it represents the constraints and interfaces on the CAISO

Controlled Grid. The FNM also incorporates a representation of the interconnections between the CAISO and other BAAs. The accuracy of the FNM is essential to fully realize the benefits of MRTU's LMP-based market design. Specifically, the FNM must reflect, as accurately as possible, the topology of the CAISO Controlled Grid, including associated transmission constraints. The FNM is used in the Day-Ahead Market, Real-Time Market, including the HASP process, and in the allocation of CRRs. It is essentially the foundation upon which the CAISO clears its Energy, Ancillary Services and CRR markets and reliably and cost-effectively manages congestion on the CAISO Controlled Grid. The accuracy of the FNM is therefore crucial for allocating the use of, and managing congestion on, the CAISO Controlled Grid.

Q. HOW DOES THE IBAA PROPOSAL RELATE TO THE FULL NETWORK MODEL?

A. Under the IBAA proposal, a representation of external transmission and resources within the IBAA is modeled in the FNM at selected locations using individual or aggregated virtual resources ("System Resources"). The selected locations are at significant or dominant transmission bus locations within the IBAA network. The individual or aggregate System Resources are then used to distribute and model the scheduled import and export transactions between the CAISO and the IBAA.

III. DESCRIPTION OF THE IBAA PROPOSAL

Q. PLEASE DESCRIBE THE "SINGLE HUB" IBAA PROPOSAL.

A. The CAISO is proposing to model the SMUD BAA and the TID BAA together as a single "Integrated" Balancing Authority Area or "IBAA." Similarly, with respect to pricing, the CAISO proposes to establish a "single-hub" default pricing rule for pricing intertie transactions between the CAISO and the IBAA. In the absence of a MEEA, the CAISO would determine the supporting injection and withdrawal locations to allow the impact of the associated Intertie Scheduling Point Schedules on the CAISO Controlled Grid to be reflected in the CAISO market processes as accurately as possible given the information available to the CAISO.

Q. HOW DOES THE IBAA PROPOSAL MODEL THE LOCATIONS OF THE SYSTEM RESOURCES IN THE EXTERNAL BAAS?

A. As reflected in Section 27.5.3 of the proposed tariff language, the CAISO will associate the System Resources with the Intertie Scheduling Points between the IBAA and the CAISO Controlled Grid using resource identification information ("Resource IDs"). When a Market Participant submits a Bid, which includes and Economic Bid or Self-Schedule but referred to herein as a "schedule", at one of the affected Intertie Scheduling Points, the schedule is not modeled as an injection at the Intertie Scheduling Point; rather the schedule is mapped back and modeled as an injection at the System Resource that reasonably, based on data available to the CAISO, reflects the location of the resources used to implement the interchange transaction. As described by Dr. Harvey, this modeling approach is comparable to that of the "Proxy Bus" approach used in the Eastern

RTO's for modeling the impact of transactions from neighboring Balancing Authorities on the applicable RTO's system. (*See* Exhibit ISO No. 3 at 5-6, 31).

Q. WILL MARKET PARTICIPANTS BE ABLE TO SPECIFY THE SYSTEM RESOURCE AND ASSOCIATED RESOURCE ID USED TO SUPPORT AN INTERCHANGE TRANSACTION?

A. No. Absent an MEEA with the CAISO in which a Market Participant agrees to provide the CAISO with information regarding the location and operation of the resource supporting a scheduled interchange transaction, the CAISO will use certain default System Resources identified in its Business Practices Manuals for each IBAA and associated Resource IDs.

Q. WILL THE CAISO BE ABLE TO ACCOMMODATE THE USE OF DIFFERENT SYSTEM RESOURCES AND ASSOCIATED RESOURCE IDS IF PROVIDED THE REQUISITE INFORMATION BY A MARKET PARTICIPANT?

A. Yes. The CAISO will have the software functionality necessary to define and publish Resource IDs to be used for submitting import and export Bids and for settling import and export Schedules between the CAISO BAA and the IBAA. These Resource IDs will be specified in the Master File and will associate Intertie Scheduling Point Bids or Self-Schedules with individual or aggregate System Resource injection or withdrawal locations in the FNM.

Q. WHAT SPECIFIC DEFAULT PRICING RESOURCE IDS IS THE CAISO PROPOSING TO USE FOR THE SMUD-TID IBAA?

A. Based on the above methodology and through the stakeholder process described in Attachment E of the Transmittal Letter, the CAISO has determined that all imports to the CAISO from the SMUD-TID IBAA (excluding those associated with a pseudo-tie) should be priced based on the LMPs calculated at the Captain Jack System Resource pricing point. Similarly, the CAISO has determined that all exports from the CAISO to the SMUD and TID IBAA should be priced at the LMP calculated at the SMUD Aggregated System Resource pricing point (SMUD Hub).[3] It is important to note that even though the CAISO is proposing a single default location for imports from the IBAA and a single default location for exports to the IBAA, the CAISO intends to monitor and if necessary modify the single pricing hub by adding or subtracting locations or by modifying the distribution factors used to distribute scheduled transactions.

Q. WHO WILL BE SUBJECT TO THE PROPOSED IBAA PRICING STRUCTURE?

A. In the absence of an MEEA, once the CAISO has established an IBAA, the IBAA modeling and pricing structure will apply to all schedules submitted by a Market Participant at the Intertie Scheduling Points between the CAISO and the IBAA (excluding to those schedules from a pseudo-tie). The IBAA proposal also allows for alternative pricing arrangements if an entity agrees to provide the CAISO with additional

---

[3] The SMUD Hub is comprised of the following transmission buses (using CAISO naming conventions) and will have the following Intertie Distribution Factors ("IDF"): (1) 37005_ELVERTAS 230kV with an IDF of 0.14; (2) 37010_HURLEY S 230kV with an IDF of 0.31; (3) 37012_LAKE 230kV with an IDF of 0.19; and (4) 37016_RNCHSECO 230kV with an IDF of 0.36.

information that allows the CASIO to verify the location and operation of the resources within the IBAA that are actually used to implement a scheduled interchange transaction. The alternative arrangement could be with an individual generator, a group of generators, dispatchable load, load serving entities, or an entire BAA or a group of BAAs. The key notion is that the entity with access to the necessary data provides it to the CAISO and thereby enables the CAISO to have the necessary visibility regarding the location and operation of the resources within the IBAA and can verify the scheduled resources were in fact dispatched to support the submitted schedules. As explained further below, and by Drs. Hildebrandt and Harvey in their respective testimony, this arrangement resolves the concern about scheduling and pricing inefficiencies by ensuring that the location of injection used to implement the interchange with the CAISO is known and verifiable (*See* Exhibit ISO No.2 at 16-17 and Exhibit ISO No.3 at 11, 27).

Q. WHAT IS A PSEUDO TIE?

A. Pseudo-ties are employed to transfer resources (generators or loads) from the BAA to which they are physically connected (Native Balancing Authority Area or "Native BAA") into a BAA that has effective operational control of them (Attaining Balancing Authority Area or "Attaining BAA"). Thus, pseudo-ties provide for change of BAA jurisdiction from the Native to the Attaining BAA and thus make the Attaining BAA provider of BAA services to the resource (including the energy to supply a generating resource auxiliary load needs, in case of resource outage).

Q. DOES THE CAISO CURRENTLY HAVE ANY PSEUDO TIE ARRANGEMENTS BETWEEN THE CAISO BAA AND THE SMUD OR TID BAA?

A. There are currently two pseudo-tie agreements active under the current pilot program. The Sutter pseudo-tie is a resource that is physically connected to the SMUD Native BAA, but has the CAISO as its Attaining BAA. The other pseudo-tie arrangement is the New Melones generating unit. New Melones is a resource that is physically connected to the CAISO Native BAA, but has SMUD as its Attaining BAA.

Q. HOW WILL PSEUDO TIE ARRANGEMENTS BE TREATED UNDER THE CAISO'S IBAA PROPOSAL?

A. Since the CAISO has an agreement with each pseudo-tie resource that provides the CAISO with data and visibility regarding the unit's operation (whether as the Attaining or Host BAA), the IBAA proposal does not apply to those resources that are scheduled and are part of a pseudo-tie arrangement. Therefore, under both MRTU and the CAISO's IBAA proposal, the Sutter and New Melones pseudo-tie resources will be modeled and settled at their specific location.

Q. WHAT IS THE DIFFERENCE BETWEEN A PRICING POINT AND A PSUEDO-TIE OR A DYNAMIC SCHEDULE?

A. While a Pricing Point is simply a location on the grid at which an LMP is calculated, the pseudo-tie represents, as stated above, a more a specific scheduling and control arrangement by which a resource in one BAA (Native BAA) is controlled from an AGC perspective, by another BAA (Attaining BAA). In the case of the pseudo-tie, a resource may be physically located in another BAA (Native BAA), but for purposes of scheduling in the CAISO Markets, control responsibility, and interchange management, the resource functions as a generator in the CAISO BAA. In the case of Dynamic Schedules, the resource is in another BAA from a control perspective, but the output of the generator effectively adjusts the Area Net Interchange such that interchange delivery from one BAA where the physical resource resides is affected by an amount equal to all or some portion of the resource's output. Both the pseudo-tie and Dynamic Schedule concepts are recognized by NERC. With either a pseudo-tie or Dynamic Schedules the output of the resource and the amount scheduled to and from the affected BAAs from the resource is known and the location of such schedules are observable by the receiving BAA. Therefore, deliveries of energy and deviations from such schedules are variable and can be settled like any other generator in the receiving BAA. In the case of a pseudo tie, it is appropriate to model and settle a pseudo-tie at its physical location (*i.e.*, at the location where the energy is produced). In the case of Dynamic Schedules, only the portion of the resource's output that is dynamic is visible and therefore the actual location of delivery of energy is not known. *i.e.*Since a Dynamic Schedule is less transparent and it is not possible, absent alternative arrangements, to verify the location and output of the resource supporting a Dynamic Schedule, it is appropriate to price a Dynamic Schedule on the same basis as other interchange transactions, *i.e.*, at the Pricing Point where interchange schedules between the CAISO and BAA are modeled and priced.

Q. ARE THERE DIFFERENT TYPES OF DYNAMIC RESOURCES UNDER THE CAISO TARIFF?

A. Yes. Under the CAISO Tariff, a System Resource can be a group of resources, a single resource, or a portion of a resource located outside of the CAISO BAA. As the term indicates, "Resource-Specific" System Resources are specified generating resources outside of the CAISO BAA and can be either Dynamic or Non-Dynamic Resource-Specific System Resources. Dynamic Resource-Specific System Resources may provide sufficient visibility into both the location and operation of the resources because they are required to provide telemetry from the specific resource under the Dynamic Scheduling Agreement. Currently, if a System Resource is Dynamic but not "Resource-Specific" or if the System Resources is Resource-Specific but "Non-Dynamic" it will not provide enough visibility to the CAISO and will be treated similar to Non-Dynamic System Resource under the IBAA proposal. The reason for treating a Dynamic System Resource that is not "resource-specific" in this manner is because the Dynamic Schedule represents an exchange of Area Control Error ("ACE") between BAs but it is not associated with any specific resource. A Non-Dynamic Resource Specific System Resources also may not have sufficient visibility; the CAISO is further exploring the requirements for such resources, and until any changes are made they also would be treated like Non-Dynamic System Resources. In summary, under the CAISO's IBAA proposal and absent any alternative pricing agreement that provides for more data, because the CAISO will not have sufficient visibility into the location or operation of a Non-Resource Specific Dynamic System Resource or a Non-Dynamic System Resource (which includes Resource-Specific and Non-Resource Specific System Resources) such resources will be settled pursuant to the IBAA default pricing rule. However, since the CAISO will have sufficient visibility to determine the location and operation of a Dynamic Resource-Specific System Resource, such a resource can be modeled and priced at its specific location

IV. THE NEED FOR THE IBAA PROPOSAL

Q. WHAT ISSUES IS THE CAISO ADDRESSING WITH THIS FILING?

A. As reflected in Attachment E of the Transmittal Letter to this filing, in moving towards an LMP-based market, the CAISO recognized early in the MRTU process the need to model in detail certain neighboring BAAs that are more closely integrated with the CAISO's system and whose operations have a more significant impact on flows on the CAISO Controlled Grid. Such impacts vary depending on the location of the resources used to implement import and export transactions unless the BAAs are purely radially interconnected or the interconnections are controlled interfaces such as DC interfaces or use devices such as phase shifters.

Q. ARE THESE ISSUES MORE OF A CONCERN WITH CERTAIN AREAS?

A. In circumstances where a neighboring BAA's system is integrated with the CAISO Controlled Grid, the power flows on the neighboring system can have a large impact on power flows on the CAISO's system. Therefore, ignoring the impact of power flows on the neighboring system on the power flows on the CAISO's system can have serious implications on the outcome of the CAISO's Day-Ahead Schedules, unit commitments, and prices. Thus, ignoring the accuracy of power flow impacts from highly integrated BAAs could have both adverse operational and market impacts on the CAISO and its customers. Inaccurate modeling and accounting for these flows could result in not observing and resolving congestion in the Day-Ahead Market that would ultimately occur in Real-Time, or conversely, may result in unit commitment and dispatch decisions in the Day-Ahead Market that are ultimately infeasible in Real-Time (*See* Exhibit ISO No. 3 at 15-18). Such infeasibilities could result in higher re-dispatch costs but also could result in reliability problems if operational options to resolve such congestion no longer exist in Real-Time. This issue is discussed further in the testimony of Dr. Harvey (Exhibit ISO No. 3 at 15**)**. Also as further discussed in Dr. Harvey's testimony, inaccurate modeling of flows could also result in congestion in the Day Ahead Market that does not ultimately occur in Real-Time. Such "phantom congestion" can create market inefficiencies that will be imposed on the entire market. (Exhibit ISO No. 3 at 15-20). Therefore, in order to accurately and reliably manage congestion on the CAISO Controlled Grid under MRTU using an LMP-based congestion management system, the CAISO has to accurately model in its FNM the power flows or network effects on the CAISO's BAA arising from power flows on and between such integrated external areas and the CAISO, as well as provide prices that do not provide the incentive to inappropriately schedule at the interties with the external integrated BAAs. The methodology proposed in this filing enables the CAISO to model the flows in the IBAA in a manner that, absent the provision of more detailed information, reasonably and appropriately reflects where the power is actually coming from within the IBAA so that the power flow impacts of scheduled interchange transactions with the IBAA on the CAISO Controlled Grid can be appropriately captured in the CAISO's day-ahead schedules, hour-ahead schedules, dispatch, and related LMPs.

Q. WHAT EVIDENCE IS THERE OF THESE ISSUES MANIFESTING THEMSELVES IN THE CAISO MARKETS AT THE INTERTIE SCHEDULING POINTS AFFECTED BY THE CURRENTLY PROPOSED IBAA?

A. The CAISO compared actual flows to scheduled flows on interties with the proposed IBAAs. The results indicated that there is a divergence between scheduled and actual deliveries, illustrating the potential problem that could arise and therefore adversely impact the CAISO's LMP markets. In order to present a concise comparison of actual flows on interties with final intertie schedules, we organized the IBAA interties into three groups: (1) imports to the CAISO scheduled at WAPA's Cottonwood substation, (2) imports to the CAISO scheduled at SMUD's Lake and Rancho Seco substations, and (3) imports to the CAISO scheduled at the Tracy substation and substations in MID and TID. Figures 1 to 3, below present the results for the week that contains the CAISO's recorded system peak recorded during the July 24, 2006. However, review of data for longer time periods, discussed later in this Testimony shows that the patterns presented here reflect persistent trends. The data we reviewed shows that there are large differences between the scheduled contractual use of transmission and actual physical flows for each of the three groups. In the majority of hours for this week, net imports to the CAISO were scheduled on the two intertie lines from Cottonwood (from Western's Cottonwood substation to PG&E's substations at Cottonwood and Round Mountain), but the actual flow was from the CAISO to Cottonwood, *i.e.*, from PG&E's substations at Cottonwood and Round Mountain to Western's Cottonwood substation. The difference between contractual schedules and physical flows averaged 454 MW, and reached as high as 853 MW using hourly data. In the week shown in Figures 1 to 3, at Cottonwood (shown in Figure 1), 124 of the 168 hours had net scheduled imports into the CAISO but net physical flow in the reverse direction from the CAISO to the SMUD BAA. On July 25, 2006, in the hour ending at 9:00 AM, a net import of 410 MW was scheduled into the CAISO's hour-ahead market, but the net physical flow was 442.5 MW of export from the CAISO to the SMUD BAA – a difference of 852.5 MW. Further discussion of flow reversals, relative to schedules, is found later in this Testimony. In addition, exports of up to several hundred MW from the CAISO BAA to SMUD's Sacramento metropolitan area were scheduled in most hours of the week, but the typical actual daily pattern was net flows into the CAISO BAA in night and morning hours, and net flows out of the CAISO BAA to the SMUD BAA in afternoon and evening hours. The difference averaged 240 MW and reached as high as 554 MW. For the southern interties to the Western, MID, and TID networks, scheduled exports from the CAISO BAA averaged 345 MW, while actual flows out of the CAISO BAA averaged 817 MW, with the maximum difference reaching 1035 MW. Since the CAISO needs to manage network constraints for north-to-south flows through the Sacramento Valley, and has critical network constraints near Stockton (near MID and TID, and near the Tesla and Tracy substations where major CAISO Controlled Grid facilities and Western transmission lines connect), these significant and persistent differences between scheduled and actual flows mean that the CAISO cannot use the scheduled contractual deliveries to represent physical injections or withdrawals of Energy from the transmission network.

Figure 1
Import to CAISO at Cottonwood

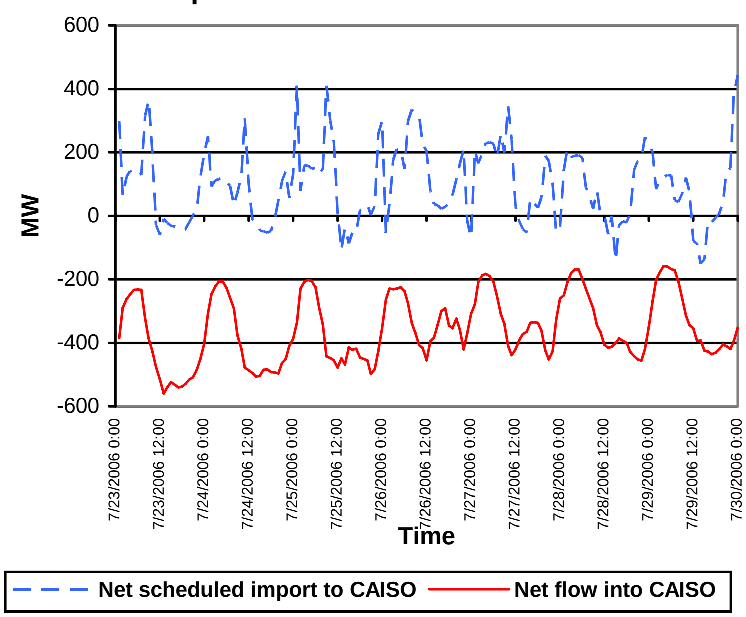


Figure 2
Import to CAISO at Rancho Seco & Lake

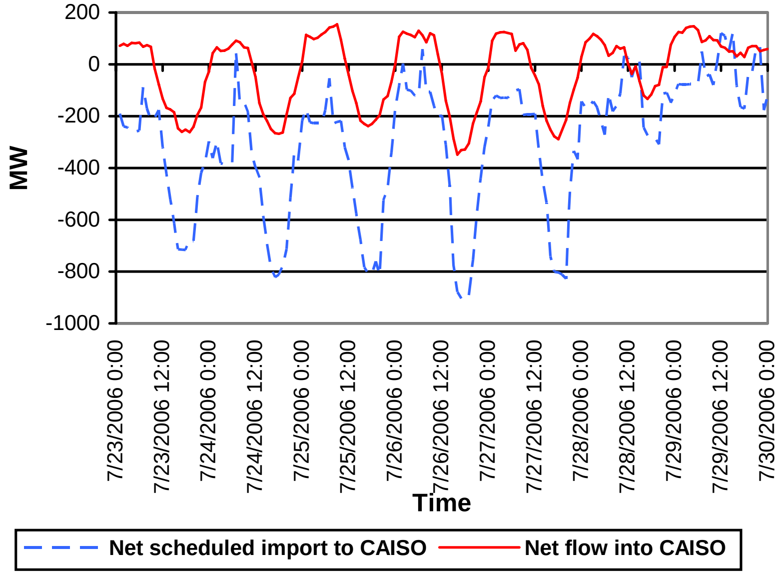
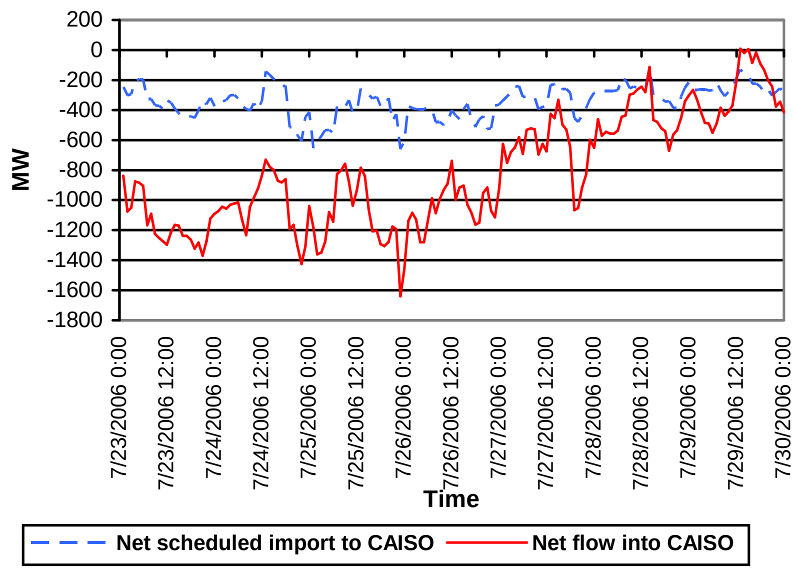


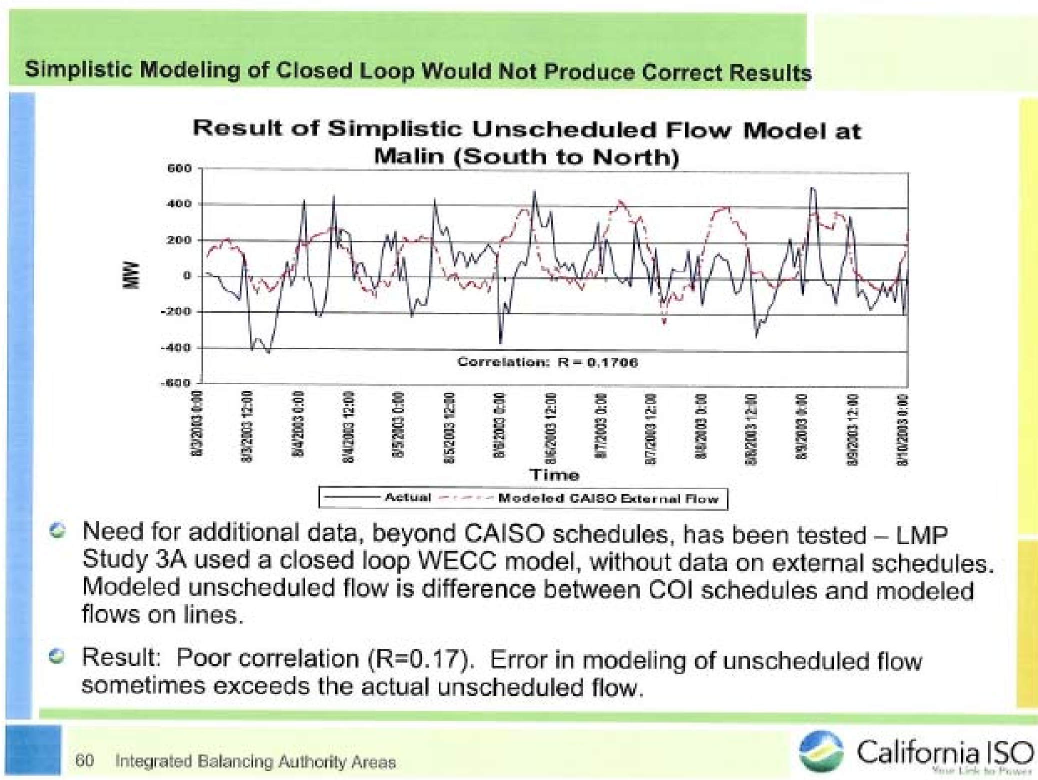
Figure 3
Import to CAISO at Southern SMUD&TID Points



Q. **COULD THE CAISO'S CONCERNS ABOUT ACCURATE MODELING BE ADDRESSED SIMPLY BY ADDING EXTERNAL TRANSMISSION TO THE FULL NETWORK MODEL, AND MODELING SCHEDULES AT THEIR CONTRACTUAL DELIVERY POINTS, I.E., THE INTERTIE SCHEDULING POINTS?**

A. No. Such action does not address the fact that the CAISO neither knows nor can validate the location of the resources actually used to implement the interchange transaction. As stated in Dr. Harvey's testimony, knowing the "location" of the resource supporting a scheduled transaction matters and is fundamentally important to the success of an LMP-based system. (Exhibit ISO No. 3 at 12). Including a representation of the external transmission system in the FNM is not sufficient with the SMUD-TID IBAA for the CAISO to ensure that the FNM can determine the impact of scheduled interchange transactions on the CAISO Controlled Grid. While modeling a scheduled interchange transaction as an injection at a Intertie Scheduling Point and distributing the resultant powers to different Intertie Scheduling Points using a representation of external transmission system is an improvement over modeling the schedule as a radial injection at the specified Intertie Scheduling Point, it is still less accurate than using a FNM that includes both a representation of the external transmission system and a reasonable approximation of the location of the resource supporting the scheduled interchange transaction.

The CAISO examined an alternative approach wherein the CAISO would only rely on a representation of the external system and determined that it was not viable as a general solution to determining the impact of scheduled interchange transactions on power flows on the CAISO Controlled Grid. In LMP Study 3A, the CAISO used a closed loop WECC model that included external transmission systems *but did not include data on external schedules*. As shown in the results, the modeled unscheduled flow is the difference between schedules on the California Oregon Intertie (COI) and modeled flows. As shown in the slide below, the results were a poor correlation (R=0.17)



.

In fact, error in modeling of unscheduled flow sometimes exceeds the actual unscheduled flow. LMP Study 3A analyzed data from Fall 2002 to Spring 2004 and demonstrates that these variances persist over the entire study period and therefore the data demonstrated that even a detailed representation of external transmission systems is insufficient to ensure an accurate model. Based on this analysis the CAISO concluded that it is necessary to include more detail regarding actual sources and sinks to improve the accuracy of the CAISO FNM.

Q. FOR WHAT OTHER REASONS DO YOU SUPPORT IMPLEMENTATON OF THE IBAA PROPOSAL?

A. Dr. Hildebrandt and Dr. Harvey discuss the inappropriate pricing incentives and the potential market uplift costs that could result by not implementing the IBAA proposal. For example, if the CAISO were to ignore the impacts of an import to the CAISO scheduled at Tracy and utilizing the COTP by modeling the source of the schedule at Tracy where this is no real source, CAISO consumers would have to pay unreasonable day-ahead costs and uplift costs associated with the resulting real time re-dispatch of resources to account for inaccurate location of dispatch resource in the Day-Ahead Market. For example, assume that there is, on average, 400 MW being imported to the CAISO using the COTP. Assuming an average price difference of $4/MWh between the Captain Jack substation (where the CAISO proposes to model such import schedules under the Default Pricing Rule) and the Tracy substation (the contract path terminus of the COTP), the difference in payments between dispatching the fictional resource at Tracy versus the likely marginal resource at Captain Jack is $14 million [400 MW x $4/MWh x 8760 = $14,016,000] in addition to any uplift costs associated with re-dispatch of resources in real time. This cost will be born by the rest of the CAISO market, since, in the absence of the IBAA proposal, such interchange transactions would not be appropriately priced and there is no established means for charging for deviations between scheduled interchange at a specific Intertie Scheduling Point and actual deliveries, *i.e.*, interchange is only settled on a net basis.

Q. WHY HAS THE CAISO CHOSEN TO IMPLEMENT THE IBAA MODELING AND PRICING METHODOLOGY IN THE SMUD AND TID BAAS FIRST?

A. First, in examining the physical characteristics and operations of the SMUD and TID BAAs and the impact of their systems on the CAISO BAA, the CAISO concluded early in the MRTU development process, as reflected in Attachment E to the Transmittal Letter, that it was important to focus its efforts to model the SMUD and TID BAAs on an enhanced basis. Second, the physical characteristics and operations of the SMUD and TID BAAs fit the characteristics of BAAs that are highly-integrated with the CAISO Controlled Grid. Third, the SMUD BAA and TID BAA are unique in that up until approximately 5 years for SMUD and 3 years ago for TID , respectively, the SMUD BAA and TID BAA were built and operated as an integrated control area with PG&E prior to April 1998 and with the CAISO thereafter. The SMUD BAA also includes the transmission systems and facilities of Western and MID. Accordingly, the CAISO functioned as the Balancing Authority Area (then referred to as a Control Area Operator) for the combined systems from April 1998 to 2004. Furthermore, PG&E coordinated operation of these systems, or portions of these systems under certain “integration” agreements entered into prior, but continued after, the CAISO became the BAA.

For all these reasons it is natural that the location of resources dispatched within the SMUD BAA and TID BAA to implement an interchange transaction with the CAISO would have a material impact on flows, congestion and losses on the CAISO Controlled Grid. As a result, the CASIO identified (in the February 9, 2006 MRTU filing and in the Business Practice Manual for the FNM as posted on the CAISO web site on July 31, 2006) the SMUD and the TID BAAs as systems it intended to model in detail in the FNM. At that time, the term that was used was Embedded or Adjacent Control Areas ("ECA/ACA"). The CAISO subsequently adopted the term "Integrated Balancing Authority Area" in order to reflect both the need to integrate such systems in detail in the CAISO's market models and systems and to conform to newly adopted North American Electric Reliability Corporation ("NERC") terminology. Later, as further explained below, the CAISO conducted additional power flow analysis that confirmed that the power flows from the SMUD and TID BAAs do indeed have a significant impact on flows on the CAISO Controlled Grid and, if not modeled appropriately, can lead to significant discrepancies between day-ahead and final real-time schedules at the interties and what actually flows in real time. As we explain above, the discrepancies result from the day-ahead schedules being based on contract path scheduling practices rather than an accurate representation of anticipated real time flows determined from application of a detailed FNM that includes both a representation of the external transmission systems and an approximation of the location of the physical sources used to support scheduled interchange.

Q. WHAT ARE THE CHARATERISTICS OF A HIGHLY INTEGRATED BAA?

A. The CAISO identified six criteria and included these criteria in its proposed Tariff Section 27.5.3.3.3. The first criterion pertains to the number of Intertie Scheduling Points between the CAISO and the relevant BAA and the distance between these Points. This is a simple but important criterion because the number of interties and the distance between them is a clear indication of how closely two BAAs are integrated. Simply put, the greater the number of interconnections, the increased potential for having flows on the other party's system. In addition, flows over interconnection points that are closely grouped together are likely to have a similar impact on the other BA's system. Conversely, flows over interconnection points that are dispersed and far apart are likely to have different impacts. Once again, location matters. For example, and as discussed below, operation of generation within the SMUD Hub will have a materially different impact on flows on the CAISO Controlled Grid than the operation of generation within the Western system.

The second criterion pertains to the extent to which significant transmission facilities within a BA operate in parallel to major parts of the CAISO Controlled Grid. When there is parallel transmission, the power flow associated with interchange transactions will not follow a contract path but rather follow the physical characteristics of the transmission lines as defined by it impedance and resistances.

The third criterion pertains to the frequency and magnitude of unscheduled flows at the applicable Intertie Scheduling Points. The fourth criterion pertains to the number of hours where the actual direction of flows was reversed from the scheduled directions. The fifth criterion applies to the availability of information to the CAISO for modeling purposes. The sixth and final criterion pertains to the estimated improvement to the CAISO's power flow modeling and congestion management processes to be achieved through more accurate modeling of the BAA.

Q. DO THE SMUD AND TID BAAS SATISFY THESE CRITERIA?

A. Yes.

Q. WHAT INFORMATION AND DATA HAVE YOU EXAMINED IN ARRIVING AT THIS CONCLUSION?

A. Our analysis is based on historical data available to us, the CAISO's own data and institutional knowledge concerning transmission system operation and topography as the previous Balancing Authority for SMUD and TID, as well as publicly available sources of information such as data posted on the CAISO OASIS site. In addition, as reflected in the graphs included in –Diagrams 1 to 12 in Attachment A, we used publicly available data on schedules versus actual flow differences from telemetry on the existing Intertie Scheduling Points between the CAISO and the SMUD and TID BAAs.

Q. HOW DOES THE SELECTION OF THE SMUD-TID IBAA MEET THE FIRST CRITERION?

A. With respect to the first criterion, the SMUD BAA is simply the BAA with the most interconnection points with the CAISO BAA. The combined SMUD BAA and TID BAA has twelve (12) interties (10-SMUD and 2-TID) (excluding the pilot pseudo-ties currently in place) with the CAISO BAA. The BAA with the next greatest number of interconnection points is the Los Angeles Department of Water and Power, which only has four interconnections with the CAISO. While, as we explained above, this is not the only factor to consider in determining potential impacts from interconnected operations, the number of interties is an indication of how closely two BAAs are integrated: a greater number of interconnections increases the likelihood that the schedules of one BAA will impact flows within the other BAA's system, as well as increasing the complexity of flow patterns between the two BAAs depending on the generation and load patterns within the integrated BAA. It is also important to note that SMUD BAA and TID BAA have an interconnection with each other such that interchange transactions can be scheduled on a contract path between SMUD and TID without scheduling through the CAISO. This fact creates the opportunity for a schedule from TID to the CAISO to actually be sourced from the SMUD BAA or even from the Pacific Northwest.

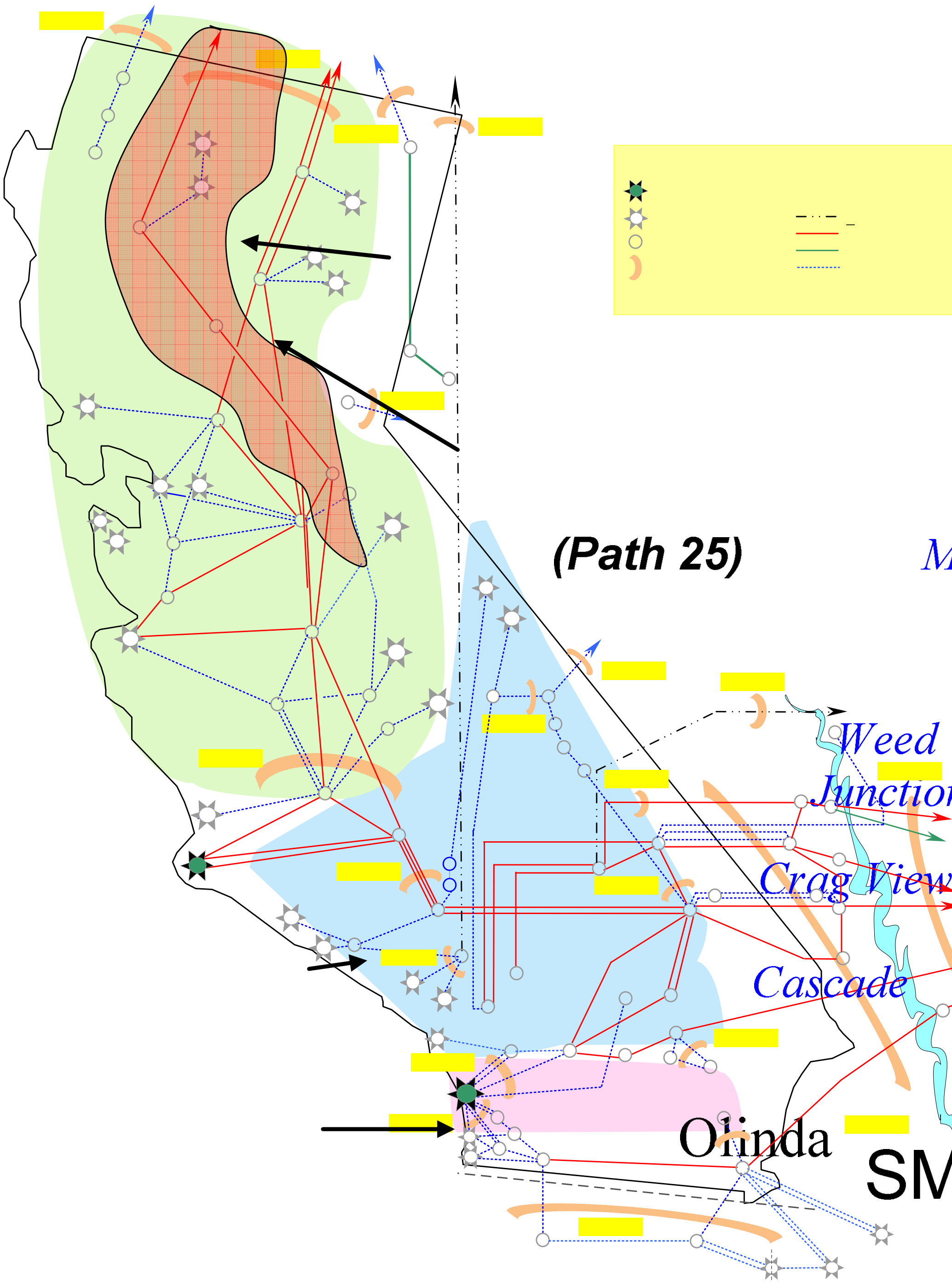
Q. WHY DOES THE SMUD AND TID BAA NEED TO BE TREATED AS ONE IBAA?

A. As previously noted the TID transmission system runs in parallel with CAISO transmission system and TID is within the former PG&E and CAISO BAA. Moreover, the SMUD BAA and TID BAA have an interconnection with each other such that interchange transactions can be scheduled on a contract path between SMUD and TID without scheduling through the CAISO and that this fact creates the opportunity for a schedule from TID to the CAISO to actually be sourced from the SMUD BAA or even from the Pacific Northwest. It is for this reason that the SMUD and TID BAA must be treated as one combined IBAA.

Q. HOW DOES THE SELECTION OF THE SMUD-TID IBAA MEET THE SECOND CRITERION?

A. With respect to the second criterion, the SMUD BAA parallels a major portion of the CAISO Controlled Grid for over 300 miles, with interconnections to the CAISO Controlled Grid (twelve, excluding Pseudo-Ties) at several locations along the 300 miles. Importantly, experience in the past has shown that significant portions of the CAISO lower-voltage (230kV and below) transmission system that parallels the SMUD BAA transmission is susceptible to congestion. In addition, there is a significant amount of generation and load located throughout SMUD and TID BAAs. These facts are important because, depending on where one schedules along the BAA boundary and compared to the location of the actual sources of interchange transactions between the SMUD-TID BAAs and the CAISO, there can be significantly different impacts on congestion on the CAISO Controlled Grid. For example, the CAISO has experienced congestion on the 230 kV transmission system between the Table Mountain and Rio-Oso substations (which are roughly half way between the Captain Jack and Tracy substations) and on other transmission lines around Rio Oso. If one were to assume an import is sourced at the COTP terminus at Tracy, the effect would be to reduce flows on the Table Mountain-Rio-Oso constraint. Whereas if the CAISO were to model the source of an import from the SMUD-TID IBAA at the Captain Jack substation, the effect would be to increase congestion on the Table Mountain-Rio-Oso constraint. The Table Mountain-Rio-Oso constraint is only one example as there are several other transmission constraints that exist on the underlying parallel CAISO Controlled Grid that can be impacted by the location of a source of interchange in the IBAA. The relationship between the proposed IBAA and the CAISO BAA is generally illustrated in Figure 4

Figure 4


(Path 25)
Meridian
Captain
(Pat
Weed
Junction
Crag View
Shasta
Cascade
Keswick
Olinda
SMUD
Table
Mountain
TID
(WAPA)
Maxwell
BAA
Geysers

Q. HOW DOES THE SELECTION OF THE SMUD-TID IBAA MEET THE THIRD CRITERION?

A. Our analysis of the unscheduled flow between the CAISO and the SMUD-TID BAAs confirms that the frequency and magnitude of unscheduled flows at the Intertie Scheduling Points between the CAISO and the SMUD/TID BAAs are frequent and unpredictable. In Diagrams 1 to 12 in Attachment A , we provide a series of charts that represent comparisons of unscheduled flow for certain external BAAs. These charts consist of frequency "bell curves" of unscheduled flow data for each intertie the CAISO has with the applicable Balancing Authority Area. This data is normalized, in that the MW difference of unscheduled flow, as measured as the difference between scheduled flow and actual flow, is divided by the respective import scheduling limit of the relevant intertie. The more hours of unscheduled flow at or around zero indicates an intertie with less unscheduled flow. The more spread out a curve is reflects an intertie with more hours of unscheduled flow. A negative unscheduled flow percentage indicates that the scheduled flow is actually greater than the actual flow from the CAISO import perspective. A positive unscheduled flow percentage indicates that the actual flow is greater than the scheduled flow from the CAISO import perspective. Looking at Diagram No. 8 in Attachment A for the SMUD BAA, we see that the frequency bell curves for the various interties are spread out and vary significantly. In addition, Diagram No. 11in Attachment A shows that the TID frequency bell curve is substantially spread out, indicating that there are frequent high unscheduled flows relative to the rating of the interconnection.

Q. WHAT TIME FRAME DOES THE DATA UNDERLYING THE DIAGRAMS IN ATTACHMENT A SPAN OVER?

A. The frequency bell curves reflect schedules and flows over the 1 year's worth of data from December 1, 2006 thru November 30, 2007.

Q. HOW DOES THE SELECTION OF THE SMUD/TID IBAA MEET THE FOURTH CRITERION?

A. With respect to the number of hours where actual direction of flows is reversed from scheduled directions, we analyzed the number of hours that the flows reversed on a number of the SMUD-TID Intertie Scheduling Points for the period beginning December 1, 2006 and ending November 30, 2007. We found that for two of the interties the direction of the flows reversed during 67 and 73 percent of the hours. On four of the interties, the flows were reversed from 33 to 45 percent of the hours.

INTERTIE	Hours of Reversal of Flow	Percentage of Hours for the Year
WESTLY_2_TESLA	5937	67
67WESTLY_2_LOSBNS	3964	45
TRACYPP_TESLA	246	3
TRACY_PGAE	2861	33
RANCHO_2_BELOTA	3117	36
LAKE_2_GOLDHL	476	5
LLNL_1_TESLA	1180	13
CTNWDW_2_CTTNWD	6369	73
CTNWDW_2_RNDMTN	0	0

Q. HOW DOES THE SELECTION OF THE SMUD/TID IBAA MEET THE FIFTH CRITERION?

A. The availability of data that the CAISO already has in its possession played a significant role in the determination to proceed with the SMUD-BAA and TID-BAA at this time. These systems were once part of the CAISO BAA and therefore, the CAISO has more extensive data available to it to enable it to determine the reasonableness of the assumptions it makes regarding the location of resources in these BAAs. The CAISO does not have the same data available to it with respect to other BAAs and therefore it cannot move to reliably implement the IBAA methodology at this time.

Q. HOW DOES THE SELECTION OF THE SMUD-TID HUB MEET THE SIXTH CRITERION?

A. We believe that the IBAA proposal for the SMUD-TID IBAA provides important improvements to the CAISO's power flow modeling and congestion management processes, which will be achieved through better modeling of resources in the SMUD-TID BAA. To determine this, we analyzed how well various methods of modeling flows compared to actual flows.

Another modeling consideration that the CAISO is concerned about is the ability to solve an AC power flow in its congestion management process. The AC power flow is very sensitive to network modeling accuracy. As a result, modeling of IBAA that is inconsistent with the physical reality can jeopardize the objective of achieving quality AC power flow solutions. We found that in testing the FNM used for MRTU, the AC solution was sensitive to the modeling of the SMUD/WAPA systems. We observed that inaccuracies in modeling can lead to unrealistic flows that can result in voltage profiles that can jeopardize AC powerflow convergence.

The CAISO compared data on total Schedules at each Scheduling Point between the CAISO and the SMUD BAA during the week of the CAISO's historical peak. Based on this analysis we conclude that there would be significant errors in the CAISO's congestion management solutions if the Scheduling Points were treated as the actual locations of Supply and Demand in the SMUD BAA. Real-Time data on SMUD BAA load is available to the CAISO (although, as discussed in Attachment E to the Transmittal Letter, SMUD may have concerns about the CAISO using the data as an input to the CAISO Markets). Using this data, as well as load distribution factors, the CAISO can develop forecasts of SMUD's BAA load. With respect to modeling generation we note that if detailed scheduling information within the SMUD Balancing Area were available, this would be the best means to model IBAA internal generation. The CAISO examined two alternatives and concluded that developing estimates of SMUD generation by using aggregated resources and Generation Distribution Factors ("GDFs") in subsystems of the SMUD BAA is a technically feasible means of improving the accuracy of the CAISO's congestion management solutions.

First, the CAISO considered a simplistic alternative that uses intertie Schedules at Intertie Scheduling Points along with data on loads for regions within the SMUD and TID BAAs in an attempt to represent the underlying generation that is supporting the identified intertie Schedules. The CAISO found that the estimation approach was a poor approximation of the actual regional distribution of supply within the SMUD and TID BAAs. Actual generation in the Sacramento area ranges between roughly 400 and 1000 MW, while the estimation approach produces a generation output of between roughly 1500 and 3000 MW for the Sacramento area. For the northern region, the actual generation varies between roughly 500 and 1100 MW, while the estimation approach produces a generation output of roughly 200 to 500 MW. For the same reasons modeling intertie Schedules and injections at Intertie Scheduling Points is not a workable solution for Congestion Management under MRTU. Attempts to combine traditional intertie Schedules with limited data about conditions in the SMUD and TID BAAs is also not a workable solution. A more realistic approach is to estimate the total amount of generation (as well as load) in the SMUD and TID BAAs, and distribute the estimated total within these areas using GDFs.

Q. DO YOUR DIAGRAMS IN ATTACHMENT A PROVIDE EVIDENCE THAT OTHER INTERCONNECTED EXTERNAL BAAS EXPERIENCE SIGNIFICANT DEGREE OF PARALLEL TRANSMISSION?

A. Yes. Diagram No. 5 in Attachment A, for example demonstrates that LADWP has the second highest number of interconnections with four Intertie Scheduling Points and it also has a high degree of transmission that parallels the CAISO Controlled Grid at two of the interties with the CAISO. Other BAAs, such as Comision Federal de Electricidad

("CFE") (shown in Attachment A, Diagram No.3) and Imperial Irrigation District ("IID") (shown in Attachment A, Diagram No.4) have two and three interconnections, respectively. In the case of CFE, the CAISO will be modeling the CFE as a closed loop which will achieve more accurate flows than had CFE been modeled as radial open loop. Modeling CFE as a closed loop will reduce the impact on modeled flows on the CAISO as a result of scheduling at either Intertie Scheduling Point. This will also decrease any LMP differences that may arise between the two Intertie Scheduling Points of CFE.

Lastly, CFE does not have any other interconnection with any other BAA except for CAISO and as a result there is less opportunity for inefficient scheduling practices that are not observable based on data the CAISO has available with regards to the CFE actual operations. On the other hand, in the case of IID, the diagram shows that the parallel flows can be significant as the frequency bell curves are significantly spread out. However, modeling this BAA as an IBAA does not sufficiently meet the criteria above as the CAISO must first conduct more analysis to determine the best way to model the IID flows and its interconnections with other BAAs that also have interconnections with the CAISO. The CAISO at present does not have access to sufficient data to predict any problems under MRTU, or identify a solution to that problem. In addition to its interconnections with the CAISO, IID has multiple interconnections to Arizona, which add complexity to the development of an appropriate model of IID as an IBAA. Without a thorough review of such flows, partial modeling of the internal IID transmission to account for parallel flows on the IID transmission between the CAISO controlled SCE and SDGE systems may actually result in less accurate flows. Therefore, additional study and potential visibility is necessary before proposing an IBAA approach for IID.

Q. WHICH OF THE AREAS YOU HAVE ANALYZED APPEARS TO BE MOST PROBLEMATIC IN TERMS OF THE CONCERNS YOU IDENTIFY ABOVE?

A. LADWP appears to be the BAA that has the next most parallel flows with four interties. For a number of reasons the CAISO has chosen not to treat the LADWP BAA as an IBAA at this time. First, the LADWP transmission system has one-third of the interconnections that the SMUD-TID BAA has with the CAISO. Second, more of LADWP's interconnections are DC controllable lines. For example, LADWP's transmission system: (1) includes the Pacific DC intertie, which is used as a device for managing regional flows through the WECC interconnection as well as for importing energy to both the CAISO and LADWP BAAs, and (2) includes the Intermountain DC intertie that connects a portion of LADWP's generation to the loads that LADWP serves, as well as serving the same function for Southern California cities that are in the CAISO BAA. It is important to note that the Southern California Import Transmission ("SCIT") interface is a significant operating constraint for the CAISO as well as the WECC as a region, and the SCIT capacity is shared by both the CAISO and LADWP as a critical link in supplying loads in each of these BAAs. Therefore, this construct must be analysied more closely and complicates the analysis such that additional studies are required before the IBAA modeling at this location can be finalized. Third, the Intertie Scheduling Points with the LADWP BAA will *not* be modeled as radial connections under MRTU. Rather, due to the fact that the CAISO has entitlements that extend into the LADWP transmission system, thereby extending the CAISO Controlled Grid into the LADWP BAA, it is necessary to model the LADWP system using a partial looped network. Due to the transmission entitlements turned over to the CAISO, it has already improved upon the radial modeling approach by including certain facilities of LADWP's external transmission system in the FNM. In fact, the market functionality that is used in the Real-Time Market to calculate compensating injections in the SMUD-TID IBAA was first developed for modeling the portion of the LADWP system that is part of the CAISO Controlled Grid and the BAAs interconnected with LADWP. The Real-Time Market functionality uses the flows at the CAISO boundary to estimate actual external sources of injections and withdrawals, as projections for future dispatch intervals.

V. IMPORTANCE OF TIMING OF FILING

Q. PLEASE EXPLAIN WHY THE CAISO IS FILING ITS IBAA PROPOSAL AT THIS TIME.

A. The CAISO is submitting this filing at this time for three primary reasons. First, the CAISO and stakeholders are making tremendous efforts to finalize system development and properly test the MRTU systems and applications. The CAISO and market participants want to validate and test the final IBAA functionality. Filing now is necessary to permit time for Commission consideration of the proposal, testing by market participants, and implementation at the state of MRTU. Second, as Dr. Hildebrandt and

Dr. Harvey discuss in their testimony it is critical to implement the CAISO's IBAA proposal at the start of MRTU to eliminate the inappropriate pricing incentives that could result in manipulation of otherwise flawed market rules and other market inefficiencies that would exist in the absence of this proposal (*See* Exhibit No. ISO-2 at 8-11; Exhibit No. ISO-3 at 6-9, 18-20, and 29-30). In order to support a Fall 2008 start of MRTU, the CAISO has committed to finalize its model and introduce the final model, pricing and settlement functionality into the final months of Market Simulation to ensure that the CAISO and Market Participant have had sufficient opportunity to understand how the Market will work under MRTU. Therefore a final decision is necessary on this subject by no later than three weeks prior to the start of the MRTU Pre-Production testing period, which the CAISO anticipates will commence at the start of September 2008. Depending on what if any changes are made to the CAISO's IBAA proposal, such changes could impact the CAISO's ability to modify models and systems in time for a Fall 2008 MRTU start.

Third, as explained above, from a modeling perspective, it is critical that the IBAA proposal be implemented at the start of MRTU to enhance the accuracy and cost-effectiveness of the CAISO's congestion management solutions for the affected Intertie Scheduling Points.

Q. AT THIS JUNCTURE IS IT POSSIBLE FOR THE CAISO TO MODEL THE INTERTIES WITH THE SMUD AND TID BAAS AS RADIAL INJECTIONS FOR THE START UP OF MRTU?

A. No. First, it would be entirely inappropriate to do so for the reasons we state herein and the reasons in Dr. Hildebrandt's and Dr. Harvey's testimony. Second, as reflected in Attachment E to the Transmittal Letter and the CAISO's February 9, 2006 MRTU Filing, the CAISO never intended to model interchange transactions with the SMUD and TID BAAs in a radial or non-integrated fashion, *i.e.*, assuming for modeling purposes that interchange transactions scheduled at the existing Intertie Scheduling Points were actually sourced at the Intertie Scheduling Points. The CAISO has been developing its FNM with the intention to model the identified IBAAs in the manner proposed and at this time it would not be possible to reverse this and still support a Fall 2008, start of MRTU. In order to implement a radial modeling of the interties with the SMUD and TID BAAs, the CAISO would now actually have to develop, test and implement a new version of the FNM. For routine network model changes this usually requires about 3-4 weeks to prepare a new FNM version for internal testing and it then requires an additional 2-3 weeks to internally test such a model. Removing the SMUD network from the FNM at this point and replacing it with a radial model would not be routine and would likely require more time than routine model changes to implement. Moreover, modeling the interconnections with SMUD and TID as radial is a significant change from how the CAISO has been modeling the SMUD and TID interconnections in the MRTU market simulations thus far. Any change to a radial model would likely deny market participants the opportunity to test and conduct market simulations with the radial model. To require the CAISO to model the SMUD and TID interties as radial interconnections would likely delay the start of MRTU into 2009. Most importantly, and as discussed by Dr. Harvey and Dr. Hildebrandt, implementing a radial model and pricing for the twelve interconnection points with the SMUD and TID BAAs would give rise to adverse reliability and market outcomes (*See* Exhibit No. ISO-2 at 8-11; Exhibit No. ISO-3 at 6-9, 18-20, and 29-30).

Q. DOES THE CAISO HAVE PLANS TO ASSESS AND DETERMINE WHETHER TO APPLY ITS PROPOSED IBAA METHODOLOGY TO OTHER BAAS?

A. The CAISO believes that it has addressed the areas of most concern with the IBAA proposal for the SMUD and TID BAAs. Nevertheless, the CAISO will continue to evaluate and apply the criteria specified above to every other BAA with which the CAISO is interconnected to determine whether, and under what priority, it should apply the IBAA methodology. The DMM and the CAISO will be monitoring the consistency of modeling and pricing of interchange transactions under MRTU. The CAISO will of course follow the process proposed in the instant filing and detailed in Section 27.5.3 of the CAISO's proposed tariff language if any expansion of the IBAA concept is warranted.

Q. WHY DO YOU THINK IT IS APPROPRIATE TO ASSESS EACH BAA SEPARATELY

A. As stated by Dr. Harvey in his testimony, it is important assess the individual characteristics of each BAA and the impacts of power flowing over all interconnections between a BAA and the CAISO on the CAISO Controlled Grid. (*See* testimony of Dr. Harvey, Exhibit ISO-3, at 27-31). Dr. Harvey notes also how the Eastern RTOs have had and continue to make adjustments to their Proxy Bus methodologies based on actual experience and changed operational parameters (*See* testimony of Dr. Harvey, Exhibit ISO-3, at 31-41).

Q. WHAT IS THE CAISO'S LONGER-TERM VISION FOR COORDINATING WITH OTHER BAAS TO DETERMINE AND MANAGE THE IMPACT OF POWER FLOWS ON ONE BAA'S SYSTEM ON ANOTHER BAA'S SYSTEM?

A. The CAISO supports the Commission's statements in the April 20, 2007 Order Granting In Part and Denying in Part Requests for Clarification and Rehearing, *California Independent System Operator Corporation*, 119 FERC ¶ 61,076 (April 20, 2007). As summarized in Attachment E to the CAISO's instant filing, in the April 20, 2007 order, the Commission reiterated that the need for better data exchange among BAAs in the west is not an MRTU seams issue and encouraged participants to work through the WECC process to resolve these issues. The Commission also reiterated its support for better modeling of external areas and encouraged parties to pursue better exchange of data to enhance modeling improvements. On a long-term basis, the CAISO agrees that a more preferable and optimal approach to modeling and pricing the impact of interchange transactions and other power flows is to work through the appropriate WECC forums and efforts towards a consensus region-wide approach through which all BAAs in the West exchange detailed information regarding day-ahead load forecasts, schedules, outages, and other information necessary to accurately determine and price the impact of power flows on other BAAs' systems on a particular BAA.

Q. SHOULD THE CAISO DEFER IMPLEMENTATION OF ITS PROPOSED IBAA METHODOLOGY AND INSTEAD FOCUS ON EFFORTS TO IMPLEMENT THE REGION-WIDE APPROACH YOU DISCUSS ABOVE?

A. No. As we discuss above, the CAISO's IBAA proposal adequately addresses the modeling concerns and enables the CAISO to appropriately manage interchange transactions with the SMUD-TID IBAA for MRTU start up. Furthermore, as described in more detail by Dr. Harvey in his testimony, not implementing the CAISO's proposal could have detrimental effects on the CAISO's market outcomes (*See* testimony of Dr. Harvey, Exhibit ISO-3, pp. 18-20).

VI. EVOLUTION OF THE PROPOSAL AND AND ALTERNATIVES CONSIDERED THROGH THE STAKEHOLDER PROCESS

A. EVOLUTION OF THE PROPOSAL

Q. HAS THE CAISO ALWAYS PROPOSED TO MODEL AND PRICE IBAAS AS PROPOSED IN THIS APPLICATION?

A. No. As the CAISO has continued to evaluate what alternatives are available to the CAISO based on the state of its MRTU software development and based on the access it has to data from the other BAAs, the CAISO's thinking on how best to model and price these closely integrated systems has changed over time. Originally, as indicated in Attachment E of the Transmittal Letter, in the CAISO's original Market Design 2002 and MRTU filings, the CAISO considered modeling neighboring BAAs using a detailed model which would have required the CAISO to, among other information, obtain detailed load forecast and resource-specific scheduling information from the affected BAAs. During the December 2006 FERC Technical Conference on seams issues, FERC Commissioners and staff expressed the desire that parties move towards a more collaborative data exchange process. Pursuant to this direction, the CAISO took additional measures to continue discussions towards furthering this effort with what it had previously identified as the most integrated BAAs.

Q. WITH WHOM DID CAISO FIRST PURSUE THESE DISCUSSIONS?

A. As indicated in Attachment E of the Transmittal Letter, having identified the SMUD and TID BAAs as the outside entities mostly closely interconnected, the CAISO focused its efforts on these entities and, beginning in the Spring of 2007, initiated discussions with SMUD and TID BAAs and other entities within these areas to exchange data and consult on how best to model and price interchange with these BAAs.

Q. DID THE CAISO AND THE SUBJECT NEIGHBORING BAAS MAKE ANY PROGRESS ACHIEVING GREATER DATA EXCHANGES?

A. While the CAISO felt that the discussions were very useful and representatives agreed that more closely coordinated operations could enable each BAA to provide more reliable service, the parties did not reach any agreement on what data could be exchanged or how such data could be used by either party. In fact, in summer 2007, it became apparent that SMUD was not prepared at that time to engage in the exchange of data necessary to support the CAISO’s then-preferred approach to modeling and pricing interchange transactions with IBAAs. Therefore, the CAISO decided to modify its approach in a way that reduced the information and input requirements but still retained the modeling accuracy needed to support MRTU. A complete description of the CAISO's IBAA development, consultation and stakeholder process is included as Attachment E of the Transmittal Letter.

B. ALTERNATIVES CONSIDERED

Q. PLEASE DESCRIBE THE OPTIONS THE CAISO CONSIDERED WITH RESPECT TO MODELING AND PRICING INTERCHANGE TRANSACTIONS WITH EXTERNAL BALANCING AUTHORITY AREAS.

A. Over the past several years, as reflected in Attachment E of the Transmittal Letter, the CAISO has considered a number of options in its attempt to determine how best to treat external control areas in MRTU: (1) an original concept of a "closed loop" design, which would have required full detailed modeling of the external WECC regional system and exchange of information, in order to provide an accurate model; (2) the "full physical model" (3) the "sub-hub" approach; and (4) the currently proposed "single hub" approach. As we explained earlier, following the Commission's conditional acceptance of the MRTU Tariff, the CAISO considered obtaining the information from all neighboring BAAs necessary to implement a closed loop model, while maintaining the required level of accuracy in modeling flows within the CAISO BAA. However, the CAISO realized that there were institutional practices and impediments that would not be easily overcome that would have prevented the CAISO from achieving its objective. The CAISO concluded at that point that it would be better to work through such forums as the

WECC to possibly achieve the objective of a closed loop model over a longer period of time. As a result, while application of a closed loop model was preferred by the CAISO because it was the most accurate approach, the CAISO began to examine alternative approaches when it became apparent that the information needed to implement the closed loop model would not be forthcoming. The first approach to modeling and pricing IBAAs the CAISO considered was use of a "full physical model" of the IBAA where the CAISO thought it had or could obtain sufficient data to model both "base schedules" (internal generation and load) as well as the sources and sinks supporting interchange transactions between the CAISO and the IBAA in order to model such sources and sinks at the physical locations where energy is produced or consumed. The term "base schedules" refers to internal supply schedules that are used to meet the internal IBAA demand. Modeling of base schedules was intended to reflect the full power flow effects of not just the interchange transactions with the CAISO but also the flow effects on the CAISO grid of internal IBAA flows resulting from IBAA supply serving IBAA demand. In addition to base schedules, the CAISO's original proposal would have modeled import transactions with the CAISO at the physical generator locations within the IBAA that were supporting such transactions. Export transactions would have been modeled and distributed based on the estimated load distribution factors of the demand in the IBAA. This approach was considered to be the most accurate approach, other than the full regional model. As explained at the Seams technical conference, the CAISO was seeking to work with the IBAA to share the data necessary to implement this approach. In anticipation that the necessary supporting data may not be forthcoming, the CAISO also was prepared to estimate the base schedules. However, based on discussions with the IBAAs and other external BAAs that occurred after the Seams conference, it became apparent the potential IBAAs would not provide the minimum data necessary for the CAISO to make the "full physical model" possible. Furthermore, the IBAAs expressed concern that by the CAISO modeling and pricing interchange transactions at physical locations internal to their systems, the CAISO would expose internal IBAA information that the CAISO had no authority to calculate and publish and that the CAISO would reveal internal IBAA locational prices and thereby impose the CAISO's LMP market structure on the IBAAs.

Q. WHY IS THE CAISO NOT PURSUING THIS APPROACH WITH THE SMUD-TID BAA?

A. While the CAISO continues to believe that its original proposal is the most accurate approach to modeling flows on, and interchange transactions with, external BAAs, based on their representations, the CAISO concluded it was unlikely that the CAISO and the SMUD-TID BAA could agree on sharing the necessary data to make this approach workable and concluded that continued pursuit of this approach would create too great a risk to the MRTU project. In spring 2007, the CAISO began to investigate other alternative approaches.

Q. DID THE CAISO IMMEDIATELY CONSIDER THE SINGLE HUB APPROACH PROPOSED IN THIS PROCEEDING?

A. No. After evaluating several approaches, the CAISO advocated what it characterized as a "sub-hub" IBAA modeling and pricing approach.

Q. PLEASE DESCRIBE THE "SUB-HUB" APPROACH.

A. Under this approach, the CAISO would map submitted interchange schedules back to the market-participant identified supporting System Resource at one of six sub-hubs: SMUD, Western, MID, Roseville, TID, and Captain Jack. Once the schedules were mapped back, the CAISO would model the scheduled interchange as injections coming from the identified System Resource. For aggregated System Resources, such as the SMUD and Western Hubs, the injections would be distributed to the locations/facilities that comprise the Aggregated System Resources pursuant to pre-determined Intertie Distribution Factors. The degree of modeling accuracy with this approach was in part dependent on an accurate representation, by the scheduling entity, of the supporting System Resource (e.g., SMUD Hub, Western Hub, Captain Jack, etc.) for an interchange transaction with CAISO. With respect to pricing, the CAISO similarly proposed to establish discrete prices for each of the six initially identified System Resources or Aggregated System Resources anticipated to support intertie transactions between the CAISO and the SMUD and TID IBAAs. The sub-hub approach attempted to abstract the source and sink of the transactions and thereby reduced the CAISO's reliance on data from the IBAA. The CAISO performed analysis to compare how well this approach would match actual flows. It was determined that with tuning of the hub-distribution factors a reasonable correlation between modeled and actual flows could be achieved.

Q. WHY DID THE CAISO CHANGE FROM ITS SUB-HUB PROPOSAL?

A. The CAISO modified its proposal to address concerns raised by the DMM and MSC, and its expert consultant Dr. Scott Harvey about relying on potentially unverifiable representations as to the actual location of System Resources. Considering the issues identified with the "sub-hub" approach as reflected in Drs. Harvey and Hildebrandt's separate pieces of testimony, the CAISO pursued the development of the single hub approach. However, the CAISO will retain the functionality to implement the sub-hub based modeling functionality, provided the CAISO has access to appropriate data from these areas which could be obtained through an MEEA because of the more accurate modeling representation it provides. In addition, the CAISO has retained the ability to move to the "full physical model" functionality, if the detailed exchange of data is made possible in the future through regional coordination efforts or agreements, as is being considered in such forums as WECC's Seams Issues Subcommittee.

Q. WHAT CONCERNS EXIST WITH THE "SUB-HUB" APPROACH?

A. With respect to pricing, and as discussed in Dr. Hildebrandt's testimony, the DMM, the MSC and Dr. Harvey, noted that the sub-hub based pricing methodology was subject to concerns about incentive compatibility and verifiability of source of transactions. Since the Multiple-Hub methodology was based on Market Participants identifying the resources supporting a given intertie transaction or set of transactions, the MSC, the DMM, and Dr. Harvey, stated that it would create strong incentives and rationale for market participants to specify schedules that would maximize their market revenues, *i.e.*, buy low, sell high, and not reveal the actual location and operation of the specific resources supporting the intertie transaction (information that is critical to the CAISO obtaining a reasonable approximation of the impact of such transactions on the CAISO Controlled Grid). Dr. Harvey provided to the CAISO and stakeholders the experience of Eastern ISOs with inefficient scheduling and pricing concerns arising from multiple hubs as explained in his testimony. In addition, the MSC recommended that the CAISO minimize or further confine the pricing options available to entities scheduling intertie transactions between the CAISO and the proposed IBAAs. If the CAISO did not move to the single hub proposal, the market design or market rules would permit a participant to profit without providing a commensurate benefit to grid operations. For example, if the CAISO were to pay for generation redispatch to resolve a congestion problem but the generation is not located at the necessary location (and may in fact exacerbate rather than relieve the problem) this would be a situation that results in unjust and unreasonable payments. Dr. Harvey's testimony describes how the invisibility of actual generation sources beyond the CAISO's border can produce opportunities to profit in manners that do not contribute to grid reliability. It is important to try to prevent such occurrences which erode confidence in market operations.

Q. DOES THIS MEAN THAT PRICING FOR ALL OF THE TWELVE SCHEDULING POINTS WILL BE IDENTICAL UNDER ALL CIRCUMSTANCES?

A. No. If a scheduling limit is reached or "hit" at one of the Intertie Scheduling Points, the Captain Jack-associated price for that Intertie Scheduling Point will separate from the other default Captain Jack associated prices for other Intertie Scheduling Points. This is expected to occur rarely since external BAAs limit the amount of schedules at the Scheduling Point pursuant to their established contract path and Open Access Transmission Tariff reservations. Another example of a situation where the Captain Jack price for a specific Intertie Scheduling Point may be different is in the case of the COTP transmission rights that are considered CAISO Controlled Grid (approximately 33 MWs of the COTP's 1600 MW capability are under CAISO operational control and thus part of the CAISO Controlled Grid). To the extent schedules exceed the 33 MW of COTP entitlement that are considered CAISO Controlled Grid and the CAISO has to impose the scheduling limit to manage congestion, the Captain Jack price for use of such COTP entitlements would separate from the prices at the Captain Jack prices associated with other Intertie Scheduling Points.

Q. WHAT IS THE DIFFERENCE BETWEEN THE PRICE SEPARATING WHEN THE INTERTIE SCHEDULING LIMIT IS EXCEEDED VERSUS HAVING PRICES SEPARATE IF THE INJECTIONS WERE MODELED AT THE ACTUAL SCHEDULING POINT?

A. The difference is that when all the Intertie Scheduling Points are priced at Captain Jack the price will only separate if an individual Intertie scheduling limit was binding. However, if the Intertie Scheduling Point were modeled and priced at the boundary of the CAISO and the IBAA, the price at different Intertie Scheduling Points could separate when there was flow-based congestion on the CAISO Controlled Grid or due to difference in Marginal Losses at the different Intertie Scheduling Points. As a result the price would be expected to be different at different Intertie Scheduling Points modeled at the boundary most of the time.

Q. WHY DOES THE CAISO MAINTAIN INDIVIDUAL SCHEDULING LIMITS INSTEAD OF AN AGGREGATE SCHEDULING LIMIT WITH IBAA?

A. Based on WECC and NERC scheduling practices, neighboring Balancing Authorities must establish and register the interconnections at which they will coordinate schedules between Balancing Authorities and perform tagging and checkout processes. In December 2004 and December 2005, when the SMUD and TID BAA were formed, the CAISO, SMUD and TID discussed and agreed on the existing 12 intertie scheduling location and associated limits. While the CAISO does believe there are efficiencies to be gained by consolidating the 12 individual intertie scheduling limits into a few aggregate BA to BA interface scheduling limits, such an action will require coordination agreements with interconnected BAAs and possibly regional studies to establish such aggregate scheduling limits. As a result, the CAISO is proposing to maintain the 12 individual Intertie Scheduling Points and associated limits.

Q. WHAT FACTORS DID THE CAISO CONSIDER IN MOVING FROM THE SUB-HUB TO THE SINGLE HUB METHODOLOGY

A. The CAISO considered how each approach would improve the accuracy of the FNM, whether it would improve the effectiveness of the CAISO's congestion management process and whether it would reduce opportunities for using the market rules to profit without producing commensurate benefits to grid management and utilization. Because of the concerns raised by the MSC, DMM and Dr. Harvey, the CAISO has placed an initial premium on reducing the price differential opportunities. Such an emphasis should not be surprising since one of the primary objectives of MRTU is to prevent the market abuses that precipitated the California Energy Crisis of 2000-2001. Over time and with better data, the CAISO would want to utilize more detailed modeling and pricing points. However, the caution of the MSC and Dr. Harvey is that the CAISO should only do so if the entity selling into the CAISO market is willing and able to provide the data verifying the location of the supply.

VII. SPECIFIC ISSUES RELATED TO THE PROPOSAL

A. PRICING CHARACTERISTICS

Q. PLEASE EXPLAIN WHY THE CAISO CHOSE THE CAPTAIN JACK SUBSTATION AND THE SMUD HUB AS THE DEFAULT PRICING POINTS FOR, RESPECTIVELY, IMPORTS AND EXPORTS, UNDER THE CAISO'S SINGLE HUB PROPOSAL.

A. The CAISO selected the Captain Jack and SMUD hub System Resource pricing points as the default pricing points for, respectively, all imports to and exports from the CAISO system from the SMUD and TID IBAA in order to eliminate the "circular scheduling" concern discussed in Dr. Hildebrandt's testimony (*See* Exhibit No. ISO-2 at 9-11). Since the CAISO selected a low priced location as the default location for pricing all imports (sales to the CAISO) and a high priced location for the default location for pricing all exports (purchases from the CAISO), the CAISO has eliminated the price incentive to simultaneously buy at low priced locations such as Captain Jack and sell at high priced locations such as the SMUD hub. In addition, by selecting the Captain Jack System

Resource pricing point as the default location for all imports to the CAISO, the CAISO has reduced the likelihood that Market Participants will take advantage of potential artificial price differences between the Malin ISP (Malin is the ISP between the CAISO and the Bonneville Power Administration) and an alternative and higher default pricing point for imports to the CAISO from the SMUD and TID IBAA.

Q. PLEASE EXPLAIN.

A. First, let me explain that the CAISO expects that the prices at the Captain Jack System resource and the Malin substation will typically be the same when the scheduling limit at Malin is not binding. This is because Captain Jack and Malin are separated by a 500 kV low-impedance transmission line that is not usually congested. Therefore, the LMPs at each location should be the same or very similar. Second, if the CAISO were to establish the default price for imports from the SMUD and TID IBAA based on, for example, a weighted average of all the System Resources associated with the SMUD and TID IBAA, that price would likely be higher than the price calculated at the Captain Jack System Resource (and lower than the LMP associated with the SMUD hub System Resource). Under this scenario – an import price that is higher than the expected Captain Jack-Malin price – the CAISO is concerned that Market Participants will have an incentive to purchase (export) from the CAISO at Malin and sell (import) to the CAISO at the weighted average single hub import price (*See* Exhibit No. ISO-2 at 9-11).

Q. WHY DO YOU BELIEVE THAT IT IS REASONABLE FOR THE CAISO TO SELECT PRICING LOCATIONS THAT ARE THE MOST ADVANTAGEOUS TO THE CAISO, I.E., BUY LOW AND SELL HIGH?

A. The CAISO has an obligation to ensure that prices on its system and in its markets are just and reasonable and that it cost-effectively manages congestion on the CAISO Controlled Grid. While the CAISO must accept all qualified offers to sell and buy into its markets, the CAISO has the right and responsibility to establish an appropriate price and terms for such sales and purchases. As discussed in the testimony of Dr. Hildebrandt and Dr. Harvey, absent the provision of information to the CAISO that would support an alternative pricing arrangement, the CAISO must establish market rules and related prices that eliminate inappropriate price incentives and reduce the risk to CAISO Market Participants of 1) paying too much for power, and 2) paying for the cost of the real time redispatch necessary because the CAISO procured and paid for power that was not representative of the value of such power to the CAISO for managing congestion on the CAISO Controlled Grid (*See* Exhibit No. ISO-2 at 8-16; Exhibit No. ISO-3 at 7, 15-20).

Q. ARE THERE ANY OTHER REASONS WHY THE CAISO BELIEVES THAT THE CAPTAIN JACK AND SMUD HUB SYSTEM RESOURCES ARE REASONABLE DEFAULT PRICING POINTS?

A. Yes. The CAISO believes that the Captain Jack and SMUD hub System Resource pricing points are, in the absence of more detailed information, reasonable approximations of the marginal resources likely to support, respectively, imports and exports to the CAISO from the SMUD and TID IBAA. On any given day, the CAISO believes that it is a reasonable assumption that entities within the SMUD and TID IBAA will procure generally less expensive power available from the Pacific Northwest. Absent information that verifies that such entities are not dispatching their own internal generation to support a scheduled import to the CAISO, the CAISO believes that the Captain Jack System Resource represents a reasonable approximation of the marginal resources likely to be used to support the scheduled interchange transaction. Similarly, with respect to exports from the CAISO to the SMUD and TID IBAA, the CAISO believes that such exports will generally be scheduled to serve load in the SMUD area (as represented by the SMUD hub), since that is the location in the SMUD and TID IBAA with the greatest amount of load. Of course, in order to effect an export from the CAISO to the SMUD BAA, the SMUD BA would reduce high-cost generation in its area.

Q. ARE THE DEFAULT SYSTEM RESOURCE PRICING POINTS INTENDED TO ALWAYS ACCURATELY REPRESENT THE MARGINAL RESOURCE SUPPORTING A GIVEN INTERCHANGE TRANSACTION?

A. No. As stated above, these are intended to be reasonable approximations designed to eliminate inappropriate pricing incentives and reduce risk to CAISO customers and grid users. Moreover, as stated by Dr. Harvey in his testimony, in the absence of detailed information, a system operator has to make reasonable assumptions regarding how a neighboring Balancing Authority is going to support scheduled interchange (by moving generation on its system) so that it can reliably and cost-effectively manage congestion on its system. As discussed by Dr. Harvey, “proxy buses” are a tool that allows system operators to approximate the location of the marginal resource supporting scheduled interchange and will not be “right” all of the time (Exhibit No. ISO-3 at 13-14, 22). The

CAISO's proposal is fully consistent with the proxy bus methodology employed by the Eastern RTOs (Exhibit No. ISO-3 at 31, 38).

Most importantly, the CAISO's proposal and the location of the pricing point creates the proper incentive. It best protects the CAISO's Market Participants. If the external entities – the parties with the data – are willing to provide it to the CAISO to verify the location and operation of the resources supporting scheduled interchange, then the CAISO has offered to modify its approach to utilize the more detailed modeling and pricing information. It is only in the absence of the agreement of those with the data to provide it that the CAISO must act in this prudent and conservative manner.

Q. IS THE CAISO'S PROPOSAL TO USE THE CAPTAIN JACK AND SMUD HUB AS THE DEFAULT PRICING LOCATIONS BETTER THAN USING RADIALY MODELED INTERTIE SCHEDULING POINTS?

A. Yes. The CAISO's proposal to use the Captain Jack and SMUD hub System Resources as the default pricing points and as the approximate locations of the sources supporting imports and exports to the CAISO is more reasonable and, absent more detailed information from the SMUD and TID IBAAs and other entities regarding their internal schedules and other information, potentially a more accurate modeling assumption.

Q. DOES THE CAISO EVER ANTICIPATE A NEED TO MODIFY THE DEFAULT PRICING LOCATIONS?

A. As fully explained in the testimony of Dr. Harvey, an important lesson from the Eastern RTO markets is that the CAISO must be ever vigilant in monitoring and making appropriate adjustments to its interchange modeling and pricing rules. While the CAISO believes that the selection of the Captain Jack and SMUD hub System Resource pricing points as the default pricing locations for, respectively, imports to and exports from the CAISO from the SMUD and TID IBAA is just and reasonable, the CAISO is cognizant of the need to monitor how such pricing rules perform relative to other potential options (*e.g.*, a weighted average single hub price), and if necessary modify the pricing rules. While the CAISO has committed to conduct a stakeholder process prior to modifying the rules regarding any established IBAA and intends to fulfill that obligation, the CAISO must be able to move quickly should anomalous market outcomes arise from established market rules.

Q. WHY DID THE CAISO NOT SELECT TRACY AS THE DEFAULT PRICING POINT LOCATION?

A. The Tracy Intertie is unique in that it is a high-capacity intertie in the middle of the CAISO Controlled Grid *at which no physical generation is located*. Thus, while Tracy serves multiple alternative sources and sinks that are not electrically near Tracy, it would be inaccurate to treat Tracy as a "source" point or proxy bus under the CAISO's IBAA proposal. A transaction at Tracy does not represent a physical delivery of supply at Tracy, but rather is representative of an adjustment to net interchange between the CAISO and another BAA. Therefore, the source of a transaction/schedule is in fact the sending of a BAA's entire portfolio of resources used to control net interchange. In instances where transactions at Tracy are sourced from the Northwest, it is more accurate to model such transactions where BPA is measuring and managing its net interchange –

at Captain Jack – because of the proximity of that point of interchange with the point of interchange between BPA and the CAISO – at Malin. In other words, the impact on the CAISO Controlled Grid from a Tracy schedule that is actually source from the Northwest is very similar to a Schedule at Malin as the ultimate source is Northwest generation.

While Intertie locations with other BAAs do not have physical generation, similar to Tracy, Tracy is unique with respect to its network location and capacity in that the Node is located in the middle of the CAISO Controlled Grid as opposed to being located on the perimeter of the CAISO Controlled Grid. The network proximity and the resulting parallel transmission, as well as the multiple number of the alternative interties with the SMUD/WAPA BAA, creates more significant powerflow modeling and accuracy issues, and potential for dispatch inefficiencies than other intertie locations with other BAAs. Therefore, in using the Tracy Intertie Scheduling Point, it is necessary to recognize the source of physical flows in the CAISO network for CRR and LMP purposes. Having inaccurate assumptions about the source of transactions scheduled at Tracy can lead to discrepancies between scheduled and actual flows and increase the CAISO's cost of resolving such discrepancies. It is inappropriate to have a continued expectation of market outcomes that is based on a less accurate modeling of external systems and interchange transactions.

Q. DID THE CAISO ANALYZE WHETHER MODELING TRANSACTIONS AT THE TRACY SCHEDULING POINT WOULD BE INACCURATE?

A. Yes. During the time period when the CASIO was proposing a multiple or six hub approach, TANC asked the CAISO for data indicating whether injections at Captain Jack had a materially different impact on the CASIO Controlled Grid than injections at the SMUD Hub or the WAPA Hub. The CAISO ran optimal power flow simulations that were built from a base case that was previously used to construct a table on page 10 of the CAISO's December 14, 2007 white paper: "Discussion Paper: Modeling and Pricing Integrated Balancing Authority Areas Under the California ISO's Market Redesign and Technology Upgrade Program" ("*Modeling & Pricing Discussion Paper*"). This is posted on the CAISO website at http://www.caiso.com/1cb4/1cb4e1a154060.pdf. We also should note that the CAISO published another paper on December 14, 2007 entitled: "MRTU Release 1 Implementation of Preferred Integrated Balancing Authority Area Modeling and Pricing Options" ("*Release 1 Implementation of IBAA Modeling & Pricing Options*"). The *Release 1 Implementation of IBAA Modeling & Pricing Options* paper can be found at http://www.caiso.com/1cb4/1cb4e0984a670.pdf. The power flow simulation took an assumed 100MW injection at Captain Jack and compared it to the base case. The CAISO also did the same thing (*i.e.*, assumed a 100MW injection) at the WAPA Hub the SMUD Hub, and at *the Tracy 500kV interconnection point.*

Q. WHAT WERE THE RESULTS OF THE POWER FLOW SIMULATIONS?

A. The simulation indicated that for the 100MW injection at Captain Jack, 66.2% of the flows were through the Malin to Round Mountain intertie, while only 15.3% of the flows were through the Tracy to Tesla and Los Banos 500kV interconnection point and 8.8% of the flows were through the Tracy to Tesla 230kV interconnection point. For an assumed 100MW injection at the Tracy 500kV interconnection point (*i.e.*, the equivalent of an assumption of generation at or near the interconnection point), 71% would enter the CAISO directly from the Tracy 500 kV bus. Since there is no generation at the Tracy 500kV interconnection point, the modeled flows assuming the injections occurred at the Tracy 500kV interconnection point would be significantly different from the actual physical sources and would consequently cause modeled flows within the CAISO to differ from actual flows. These results (and others) are contained in the CAISO's March 4, 2008 responses to stakeholder questions (first response). The responses can be found at: http://www.caiso.com/1f80/1f80dfea5c300.pdf. The results are independent of the contract path that would be used on e-tags because power flows depend only on sources and sinks, not on contractual arrangements.

Q. WHY HAS THE CAISO NOT USED MORE PRICING POINTS?

A. As we described earlier and Dr. Harvey and Dr. Hildebrandt explain in detail in their testimony, the use of additional pricing points, without the information necessary to verify the location of the generation scheduling the delivery results in inappropriate scheduling and pricing incentives that would adversely impact both reliability and result in higher costs to internal load (*See* Exhibit ISO No. 2 at 8-10 and Exhibit ISO No. 3 at

18-20). The CAISO has offered to utilize additional pricing points if the Market Participant enters into an agreement to provide the necessary information.

B. LOSSES

Q. PLEASE DESCRIBE HOW LOSSES ARE CONSIDERED IN UNDER THE IBAA METHODOLOGY.

A. The CAISO will not enforce transmission constraints within the IBAA. Furthermore, under the default proposal, measures will be taken to prevent the marginal transmission losses within the IBAA from affecting the prices within the IBAA and the CAISO. Therefore, the LMPs established on the CAISO Controlled Grid will not be the prices used for settlement of the IBAA, are not affected by congestion or losses within the IBAA, and only represent the marginal effect of losses and congestion within the CAISO Controlled Grid. Stated another way, the value of energy associated with transactions between CAISO and the IBAA will be based on the impact on congestion and losses in the CAISO BAA.

The IBAAs are responsible for losses within their networks. Therefore, the CAISO proposes to schedule and dispatch Bids for IBAA System Resources as if there were no losses within the IBAA network, and to use the scheduled or dispatched MWs as the basis for expected net interchange between the CAISO BAA and the IBAA. Although transmission losses within IBAAs, and on interties between IBAAs, will be fully accounted for in power flow calculations, their marginal impact will be ignored in the loss penalty factor calculations for setting the CAISO's LMPs. Specifically, the marginal impact of transmission losses will be ignored in the LMP calculations by zeroing the partial derivative contributions to the loss penalty factors from network branches within the IBAA networks and from the IBAA interties. This will only affect marginal loss rates and does not alter in any way the transmission losses within the IBAA networks, which are accurately represented in the optimal Schedule and Dispatch by the full AC power flow solution in the market optimization.

Q. WILL THE CAISO CHARGE FOR LOSSES ON UNSCHEDULED OR PARALLEL FLOWS UNDER MRTU?

A. No. The CAISO will charge for losses on *scheduled* flows in the Day-Ahead Market and the Real Time Market under MRTU, it will not charge for *unscheduled* or parallel flows. Under MRTU (and under the current market design), the CAISO accounts for parallel flows in real time.

Q. ARE YOU SAYING THERE ARE NO COSTS ASSOCIATED WITH LOSSES ON PARALLEL FLOWS?

A. No. There is cost associated with the losses on parallel flows for all BAAs. In order to maintain power balance and scheduled net interchange in real time, a BAA will generate more to make up for such losses. As a result, there is a real cost for additional generation to make up for such losses. However, the CAISO does not charge or collect money for losses from schedules that are not using the CAISO Controlled Grid even though there is a cost for losses incurred by the CAISO (due to the parallel flows associated with such schedules using non-CAISO Controlled Grid facilities). Currently each BA addresses this issue in their BAAs.

Q. HOW ARE THE CAISO'S COSTS ASSOCIATED WITH LOSSES ON PARALLEL FLOWS ALLOCATED IN THE CURRENT MARKET STRUCTURE?

A. Such losses are made up in the Real-Time imbalance market and would be allocated to all demand in the market via a neutrality charge.

Q. WILL THE TREATMENT FOR LOSSES ASSOCIATED WITH PARALLEL FLOWS CHANGE WITH MRTU?

A. No, the cost of losses as a result of parallel flow under MRTU will be settled in a similar manner as they are today. However, under MRTU the CAISO will be allocating the costs of losses that are the result of the use of the CAISO Controlled Grid more efficiently through the Day-Ahead Market and the use of the marginal loss component of the LMPs. Through the use of the LMP, the CAISO will be allocating the cost of losses to the specific day-ahead schedules that cause such costs on the CAISO Controlled Grid, as opposed to spreading it to demand as is done through the current zonal market. In other words, there will still be a real time cost of losses associated with parallel flows under MRTU, however the Day-Ahead Market and the use of LMPs will lower the amount of costs being spread to demand as compared to the current zonal market.

Q. WOULD THE DEFAULT IBAA PROPOSAL RECOVER ALL LOSSES ASSOCIATED WITH PARALLEL FLOWS THAT ARE NOT THE RESULT OF USE OF THE CAISO CONTROLLED GRID IN THE DAY-AHEAD MARKET?

A. No. As we just explained, because the CAISO will not be charging for transactions that do not explicitly use the CAISO Controlled Grid, the CAISO will also not be collecting for losses from such parallel flows external to the CAISO Controlled Grid. Therefore to the degree that the CAISO has to redispatch due to parallel flows that are external to the CAISO Controlled Grid, CAISO demand will bear all these costs through neutrality in the Real-Time Market.

Q. COULD MODELING OF "BASE SCHEDULES" AND/OR AN MEEA PROVIDE AN OPPORTUNITY TO REDUCE THE AMOUNT OF LOSSES THAT HAVE TO BE ALLOCATED TO ALL DEMAND?

A. Yes. Modeling of base schedules and an MEEA, to the extent the MEEA allows the CAISO to better model non-CAISO schedules, could improve the modeling of the parallel flows such that the losses are accounted for in the Day-Ahead Market rather than accounted for as a neutrality in the Real-Time Market.

Q. ARE COSTS INCURRED BY THE CAISO IN THE CURRENT MARKET STRUCTURE ASSOCIATED WITH CONGESTION THAT IN PART IS THE RESULT OF PARALLEL FLOWS FROM AN IBAA?

A. Yes. To the extent parallel flows from an IBAA contribute to intra-zonal congestion, the CAISO would have to re-dispatch in Real-Time to resolve such congestion. Under the current market structure, the costs of intra-zonal constraints are allocated to load within a PTO area within which the intra-zonal constraint exists.

Q. HOW ARE SUCH CONGESTION COSTS ALLOCATED UNDER THE CURRENT MARKET STRUCTURE?

A. Under the current market structure, the costs of intra-zonal constraints are allocated to load within a PTO within which the intra-zonal constraint exists.

Q. IS LOAD BEING SERVED BY COTP SCHEDULES TODAY ALLOCATED ANY OF THESE COSTS?

A. Yes, to the extent demand is in the same PTO area, the intra-zonal costs incurred are allocated to demand in that zone.

Q. UNDER MRTU HOW ARE CONGESTION COSTS ALLOCATED?

A. One of the objectives of MRTU is to allocate congestion costs in a manner that is consistent with cost-causation. Settlement using LMPs will ensure that the user of the CAISO Controlled Grid is charged in the manner consistent with impacts on the CAISO Controlled Grid.

Q. DOES MRTU INTEND TO CHARGE PARALLEL FLOWS THAT ARE NOT EXPLICITLY SCHEDULED TO USE THE CAISO CONTROLLED GRID?

A. No. MRTU has no provision for, and the CAISO has no intent to charge, schedules that are not Scheduled to use the CAISO Controlled Grid. Therefore, as discussed previously, the CAISO would not be charging COTP schedules that are sinking to the SMUD or TID area as these are not scheduled to use the CAISO Controlled Grid.

VIII. WHAT THE CAISO'S IBAA PROPOSAL DOES NOT DO

Q. HOW DOES THE IBAA PROPOSAL AFFECT THE CAISO'S SCHEDULING PRACTICES AND WECC INTERCHANGE RESPONSIBILITIES?

A. The IBAA proposal does not impact or change any of the established WECC interchange scheduling or e-tagging rules. In addition, the CAISO will continue to perform its Balancing Authority interchange check out functions and responsibilities in accordance with existing and established rules. Furthermore, by maintaining the existing Intertie Scheduling Points and scheduling limits, existing scheduling and checkout processes will be maintained.

Q. WILL MARKET PARTICIPANTS STILL BE ABLE TO SCHEDULE TO ALL OF THE ESTABLISHED INTERTIE SCHEDULING POINTS BETWEEN THE CAISO AND THE SMUD AND TID BAAS?

A. Yes.

Q. WILL THE IBAA PROPOSAL CHANGE OR AFFECT ANY OF THE ESTABLISHED INTERTIE SCHEDULING POINT SCHEDULING LIMITS, AS ESTABLISHED BY THE INTERCONNECTED CONTROL AREA OPERATING AGREEMENTS ("ICAOAS") BETWEEN SMUD AND THE CAISO AND BETWEEN TID AND THE CAISO?

A. No.

Q. HOW DOES THE IBAA PROPOSAL AFFECT THE ABILITY OF AN ENTITY TO UTILIZE ITS TRANSMISSION OWNERSHIP RIGHTS?

A. First, let me explain that under the CAISO tariff, TORs are transmission facilities that are within the CAISO's Balancing Authority Area but not part of the CAISO Controlled Grid. The IBAA proposal does not limit an entity's rights to use their transmission that is not part of the CAISO Controlled Grid. Nor does the CAISO's IBAA proposal in any way modify the CAISO's proposed treatment of TORs under MRTU. The CAISO is not proposing to amend Section 17 of the CAISO Tariff applicable to TORs. Consequently, TOR Self-Schedules, if valid and balanced consistent with the CAISO Tariff, will continue to be afforded the perfect hedge consistent with the locations specified in the TOR's Transmission Rights and Transmission Curtailment ("TRTC") Instructions. Because the TOR is internal to the CAISO BAA, the TOR Self-Schedule is not subject to the single IBAA hub price which is for interchange transactions. For example, the City and County of San Francisco ("CCSF") has a TOR that includes a scheduling priority and provides for financial Settlement based on prices established at certain Scheduling Points, as established in the TRTC Instructions. The CAISO's IBAA modeling requires mapping to specific System Resources in order to ensure effective congestion management within the CAISO BAA. In order to preserve CCSF's TOR rights under the IBAA proposal, the CAISO will establish Resource IDs to reflect CCSF's scheduling rights, and ensure that the Settlement of CCSF's TORs is consistent with how the TORs are scheduled in the Day-Ahead Market.

Q. HOW DOES THE IBAA PROPOSAL IMPACT TRANSMISSION OUTSIDE OF THE CAISO BALANCING AUTHORITY AREA AND THAT IS NOT PART OF THE CAISO CONTROLLED GRID?

A. It is important to note here with respect to the CAISO's IBAA proposal that, regardless of the pricing option, in no case does the CAISO establish prices for the use of facilities at points outside of the CAISO Controlled Grid. Rather, under the IBAA proposal, for deliveries (imports and exports) scheduled at the existing and retained CAISO-IBAA Intertie Scheduling Points, the CAISO is determining the price (value to the CAISO for purposes of managing congestion and losses on the CAISO Controlled Grid) for those scheduled transactions based on the price of the resources identified as supporting the transaction. While the identified resources may reside outside of the CAISO Controlled Grid (*e.g.*, are System Resources, as defined under the CAISO Tariff), the price or value of that System Resource will be determined by a combination of its associated bid price and its location on the larger CAISO-IBAA network (i.e., where it is injecting power) for purposes of managing congestion and calculating losses only on the CAISO Controlled Grid. While certain stakeholders have raised concerns that under the IBAA pricing proposal the CAISO would establish prices on facilities outside of CAISO control, the CAISO's proposal in fact is not proposing to price any facilities outside the CAISO control. Just as it does today, the CAISO would continue to price transactions at its interties, by establishing the rates, terms, and conditions of service over only the CAISO Controlled Grid.

Q. THE CAISO IS PROPOSING TO USE THE CAPTAIN JACK PRICING POINT AS THE DEFAULT PRICING POINT FOR IMPORTS TO THE CAISO UNDER THE CAISO' IBAA PROPOSAL. THE CAPTAIN JACK SUBSTATION IS LOCATED OUTSIDE OF THE CAISO BALANCING AUTHORITY AREA. WHY DOES USE OF THE CAPTAIN JACK PRICING POINT NOT CONSTITUTE PRICING A FACILITY OUTSIDE OF THE CAISO?

A. External entities that operate under the traditional "contract path" paradigm have raised concerns regarding the CAISO's need to determine the point of injection (source) of a transaction – especially when that point is outside of the CAISO Controlled Grid - for purposes of assessing the congestion impact of such an injection on the CAISO Controlled Grid. However, the CAISO has demonstrated that it is not pricing the external system under the IBAA proposal. The CAISO is only proposing to model and price transactions scheduled to the Intertie Scheduling Points between the CAISO and the transactions at its IBAA in a manner whereby the price at its interties reflects the value of such scheduled transaction (import or export) for purposes of managing congestion on the CAISO Controlled Grid and reflect the true cost of using its system for flows to and from such closely integrated systems. Under the CAISO's IBAA proposal, the CAISO is mapping scheduled import interchange transactions back to specified System Resources (Captain Jack) to approximate the location of the resource supporting the scheduled interchange transaction and determining the impact of an injection at that location for determining the impact of such an injection on flows on the CAISO Controlled Grid. While the CAISO is establishing a price reflective of the value of such injections at such pricing points (Captain Jack System Resource), the CAISO is only doing so to price use of the CAISO Controlled Grid.

Q. **WILL THE CAISO'S IBAA PROPOSAL AFFECT THE VALUE OF TRANSMISSION OUTSIDE OF THE CAISO CONTROLLED GRID?**

A. No. As we stated above, the CAISO is not proposing to price or charge for the use of transmission outside of the CAISO Control Grid.

Q. **TANC AND THE COTP OWNERS HAVE RAISED CONCERNS THAT THE CAISO'S IBAA PROPOSAL DOES AFFECT THE VALUE OF THE COTP. DO YOU AGREE?**

A. No. I do not agree that the IBAA proposal affects the value of COTP. Figure 5 is a graphic representation of the COTP.

FIGURE 5

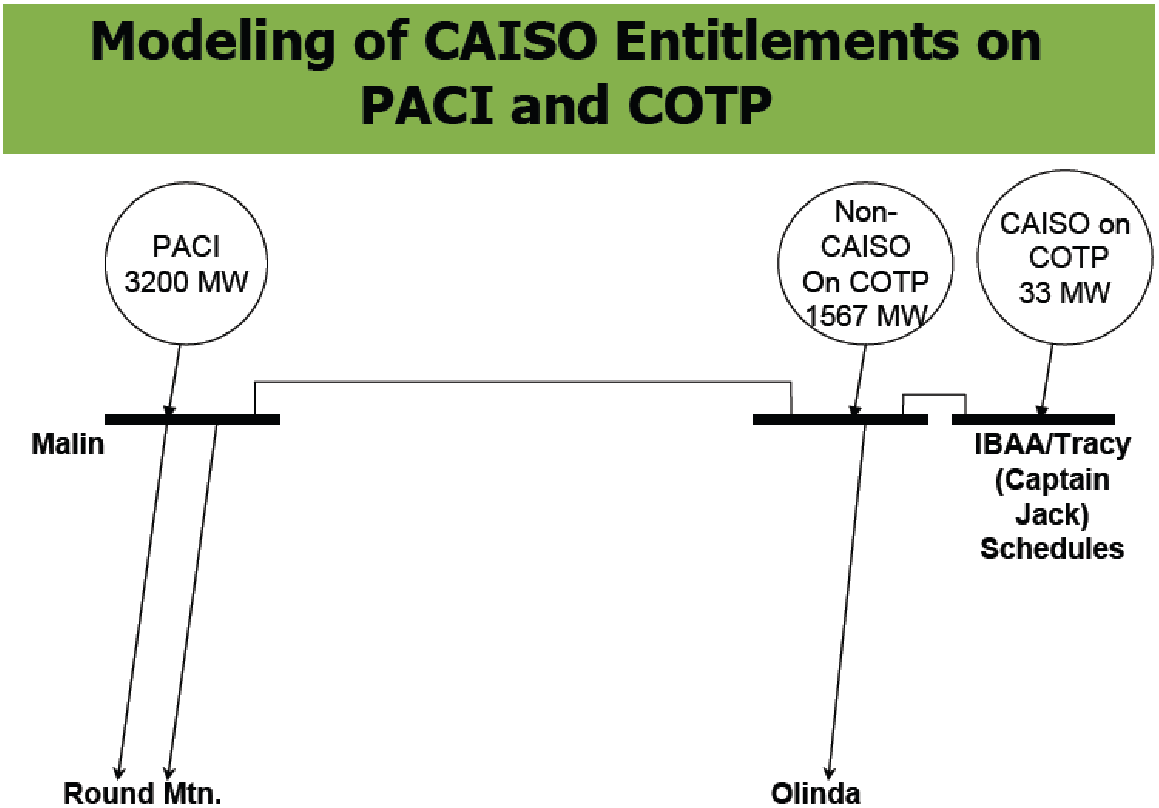
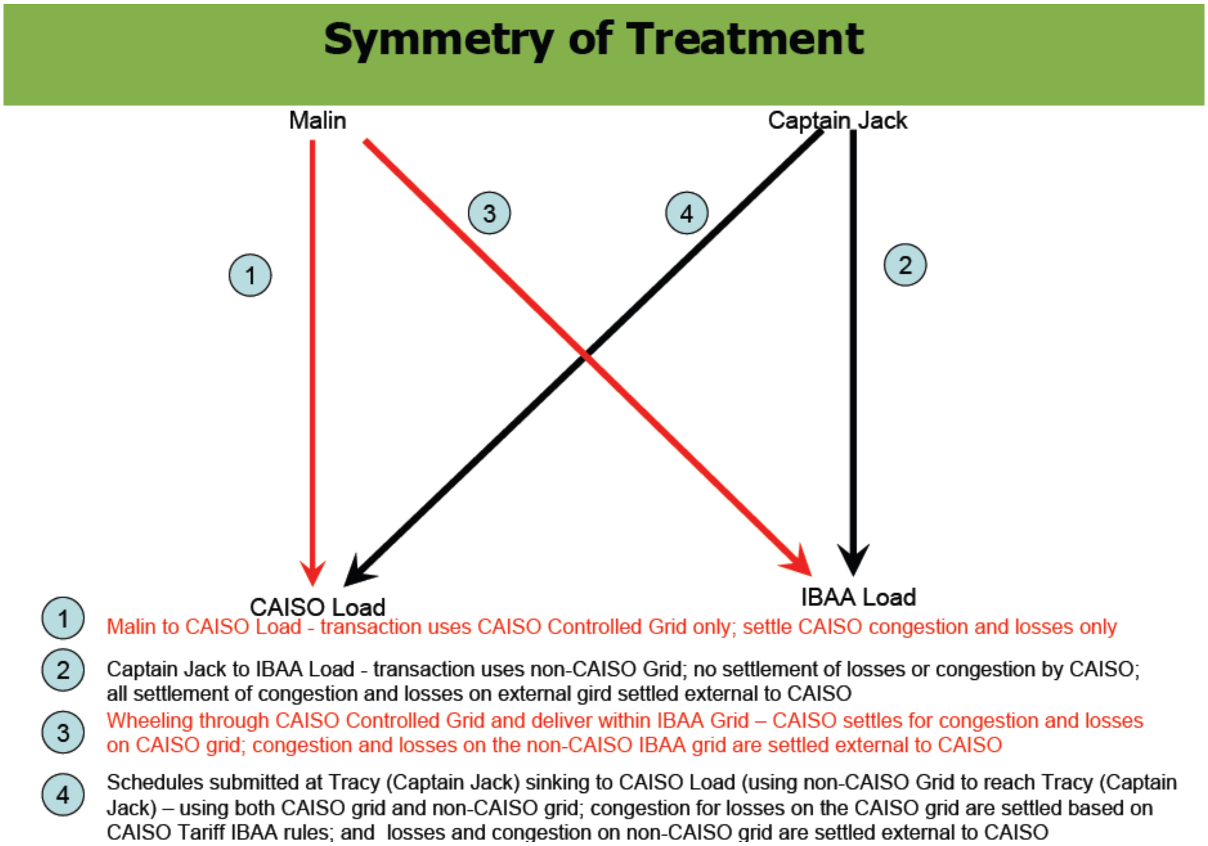


Figure 6 identifies the 4 possible transactions over COTP facilities and how each would or would not be affected.

FIGURE 6



As illustrated in Figure 5, the IBAA proposal simply has no relationship to an entity utilizing its own transmission facilities. Stated another way, TANC or any other party with an ownership right can use or sell its transmission capacity under whatever rates, terms, and conditions, it deems appropriate. The CAISO's LMP modeling and pricing takes effect only when transmission service utilizes the CAISO Controlled Grid.

Q. CAN YOU PROVIDE ILLUSTRATIONS AS TO HOW THE VALUE OF COTP TRANSMISSION IS PRESERVED FOR THE COTP OWNERS AND HOW THE

CAISO IS VALUING SCHEDULES AND CONGESTION ONLY ON THE CAISO CONTROLLED GRID AND NOT ON THE IBAA?

A. First, it is important to remember that the owners of non-CAISO Controlled Grid facilities will continue to utilize and provide transmission service over their lines and can use there facilities as they always have. Second, it is also important to remember that the CAISO has created various markets to buy and sell products that enhances the value and use of their transmission facilities above and beyond the initial use they were constructed for - to serve the owners' own load. Third, it is a simple fact of interconnected operations that changes occur that may or may not have incremental effects on neighboring systems allowing for more efficient operation and use of the entire grid. The addition or retirement of a generating facility, the construction of a transmission line, or the modification of a market rule may have an impact.

Simply stated, the IBAA proposal does not affect an external transmission owner's use of its own facilities. To the contrary, the CAISO has created new markets enhancing the demand for and value of those facilities (*See*, *e.g.*, Exhibit No. ISO-3 at 26). While changed circumstances between interconnected BAAs and transmission owners may have incremental effects, these are a normal part of utility operations. The IBAA proposal does not diminish the value of external transmission rights.

Q. HOW DOES THE IBAA PROPOSAL AFFECT THE ABILITY OF AN ENTITY TO UTILIZE ITS RIGHTS UNDER AN EXISTING TRANSMISSION CONTRACT OR TRANSMISSION OWNERSHIP RIGHT?

A. As in the case of TORs, the IBAA proposal does not modify the ability for an ETC or TOR rights holder right to schedule a transaction at a specific Intertie Scheduling Point, if the ETC or TOR rights holders is entitled to do so under its ETC or TOR. However, in the event that an IBAA Hub is established that affects the price and related settlement of schedules at a specific Intertie Scheduling Point based on the hub pricing, the ETC and TOR perfect hedge settlement accepted as part of the CAISO's MRTU Tariff would be based on the congestion component of the LMP consistent with the IBAA hub pricing at the specific Intertie Scheduling Point.

IX. DEVELOPMENT OF MARKET EFFICIENCY ENHANCEMENT AGREEMENTS – INCORPORATION OF BETTER DATA

Q. DOES THE CAISO EXPECT THAT THERE WILL BE ADDITIONAL IBAAS IN THE FUTURE?

A. As explained by Dr. Harvey, the Eastern RTOs (PJM, the New York ISO, and ISO New England) have found that operational experience and changed circumstances have required changes to the method by which these entities model and price interchange transaction pricing points used in the modeling and pricing activities of PJM, the New York ISO, and ISO New England. The CAISO certainly recognizes the need to closely monitor the relationship between its modeling results and actual observed flows over the CAISO Controlled Grid and will make changes as appropriate to improve the accuracy of the modeling outputs.

Q. WHAT DOES THE CAISO ENVISION AS THE FUTURE OF THE FNM?

A. Ultimately, the CAISO desires to model each of its interconnections with other Balancing Authority Areas pursuant to a closed loop methodology or highly integrated manner. However, maintaining accuracy in the CAISO's calculations of flows within the CAISO BAA when using a region wide closed loop model will require that the external Balancing Authority Areas share with the CAISO detailed information about the dispatch of resources (generation and loads) internal to each Balancing Authority Area with the CAISO. Currently, however, this is a topic of regional coordination that is not well developed at this time, and there has been and will likely initially be a great deal of reluctance to support the level of data exchange that is needed to implement a closed loop model in the West. While the ultimate goal of closed loop modeling is not achievable in the near term, this should not deter the CAISO from making improvements where sufficient data is available.

Q. DURING THE IBAA STAKEHOLDER PROCESS THE IBAA ENTITIES PROVIDED THE CAISO WITH A PROPOSAL CONCERNING MODELING, PRICING AND DATA EXCHANGE THAT WOULD HAVE SERVED AS AN ALTERNATIVE TO THE CAISO'S IBAA PROPOSAL. PLEASE EXPLAIN THE IBAA ENTITY PROPOSAL AND WHY DID THE CAISO NOT AGREE TO ADOPT THE PROPOSAL?

A. On May 8, 2008, the CAISO received a "Proposed Alternative to the CAISO's April 18th IBAA Proposal" provided by the IBAA Entities. While the CAISO appreciated the parties' efforts to develop additional information that the CAISO could utilize in its modeling, the CAISO had significant concerns regarding the IBAA Entities' modeling and pricing proposal.

The IBAA Entities alternative proposal had three elements: (a) data exchange between the CAISO and the IBAA Entities, (b) modeling of interchange transactions, and (c) pricing of interchange transactions ("IBAA Entity Proposal"). Specifically, under the IBAA Entity Proposal and as the CAISO understands the proposal, the exchange of data would be on a reciprocal, after-the-fact basis. The Parties would provide WECC and NERC required real-time transmission data in each other's control for reliability purposes but the data subject to the agreement could not be physically removed from each other's site. Under the IBAA Entity Proposal, the CAISO would model interchange schedules at the boundary points or Intertie Scheduling Points between the CAISO and the IBAA. With regard to pricing, the interchange schedules/bids would be settled by calculating the LMPs at the boundary locations and applying the LMPs to the scheduled quantities (MW) at each ISP.

Q. WHY DID THE CAISO NOT ADOPT THE IBAA ENTITIES' PROPOSAL?

A. While the CAISO appreciated the parties' efforts to develop additional information that the CAISO could utilize in its modeling, the CAISO had significant concerns regarding the IBAA Entities' modeling and pricing proposal.

First, the CAISO is unclear how the additional data proposed to be exchanged or made available would enhance the CAISO's modeling of the IBAAs. Second, under the IBAA Entity Proposal, the CAISO would not have visibility regarding the location of the resources within the IBAA used to implement interchange transactions; rather, each transaction would be modeled at the boundary (i.e., assuming the resources are located at or near the Intertie Scheduling Points themselves). While the IBAA Entity Proposal did provide that the CAISO would model the IBAA or external transmission system – and thus enable the CAISO to capture some of the network effects on its system by effectively distributing flows across the combined network associated with the scheduled interchange transactions – the source of such transactions would still be represented as injections at the ISPs at the boundary points. Without greater knowledge or visibility regarding the sources within the IBAA used to implement interchange transactions, the CAISO believes the prices produced at the identified Intertie Scheduling Points will not be representative of the value of the transactions scheduled at those locations for purposes of managing congestion on the CAISO Controlled Grid. Third, as described by Dr. Hildebrandt (*See* Exhibit No. ISO-2 at 21-22), the CAISO is not convinced the monitoring and information exchange process would be sufficient to address the CAISO's previously articulated pricing concerns.

Q. IS THE CAISO CURRENTLY ENGAGED IN DISCUSSIONS WITH THE IBAA ENTITIES REGARDING THEIR PROPOSAL OR WITH ANY STAKEHOLDERS ON THE POSSIBILITLY OF OBTAINING ADDITIONAL DATA TO ENHANCE FURTHER THE CAISO'S MODELING?

A. Yes. In response to the IBAA Entities' Proposal, the CAISO has continued to discuss with the IBAA Entities alternative arrangements for further exchange of data and pricing. In fact, on May 30, 2008, the CAISO sent a counterproposal to the IBAA Entities that attempted to address certain issues previously raised by the IBAA Entities.

Q. PLEASE DESCRIBE THE CAISO'S COUNTERPROPOSAL.

A. The CAISO did not provide a detailed and lengthy proposal, but instead provided a high-level conceptual proposal that the parties can discuss further. Based in part on concerns expressed by the IBAA Entities regarding the treatment of losses associated with the use of their entitlements on the COTP to support interchange transactions with the CAISO, the CAISO proposed to provide all TANC Members, that use the COTP to serve load embedded within the CAISO BAA Controlled Grid, for the amount of the load served a marginal losses exemption for the prices calculated using the System Resource located at the Captain Jack Substation and instead settle such transactions based using calculated marginal loss component of the LMP at the Tracy 500kV bus. This would essentially mean that the marginal losses will be calculated in a radial fashion assuming that the source of the import is located at or near the Tracy 500 kV ISP or bus. The sink of the transaction would be the delivery point on the CAISO transmission system. Important, however, is the fact that this exemption would only be granted in return for the provision of additional data by the TANC member IBAA Entities, which the CAISO would have to be able to use to enhance its modeling. In addition, the conceptual proposal would allow the CAISO to incorporate the COTP line into the CAISO's Marginal Loss calculation to more fully collect Marginal Losses associated with schedules using the CAISO Controlled Grid. The default treatment in modeling an IBAA, which is to include only the transmission that is within the CAISO in the calculation of the marginal loss component of LMPs, is premised on the resulting charges for marginal losses being applicable from the physical sources of Schedules to their physical sinks. When the marginal loss charges for COTP schedules are based on a contractual delivery to Tracy instead of the default source at Captain Jack, the default calculation for the marginal loss component of LMPs would produce an under collection of marginal loss revenues, which would need to be recovered from the remaining CAISO market participants. Incorporating the COTP line in the CAISO's Marginal Loss calculation will partially offset this under collection by more fully accounting for the losses between Captain Jack and the CAISO BAA.

Q. HAVE THE PARTIES DISCUSSED THE DETAILS OF THIS PROPOSAL?

A. At the time of this filing, the parties have not yet had an opportunity to meet and discuss this counter proposal, but have discussed a possible date to meet.

Q. CAN YOU PLEASE DESCRIBE IN GREATER DETAIL HOW THE CAISO CONTEMPLATES THE ALTERNATIVE ARRANGEMENT WOULD WORK?

A. While this has not been discussed or agreed to by the parties at this time, the CAISO contemplates that it would be appropriate that this proposed treatment of losses would be limited in amount to the following: the megawatt of load internal to the CAISO BAA, minus any portion of the load served by generation internal to the CAISO BAA and/or other purchases that do not use the COTP to deliver the purchased power to the CAISO Controlled Grid. The CAISO also believes that this treatment would have a defined term to be agreed to by the parties but probably not to exceed a term of two years. The CAISO also contemplates that any successor agreement or extension of the exemption would require the mutual agreement of the CAISO and IBAA Entities.

Q. WHAT KIND OF DATA WOULD THE CAISO EXPECT TO RECEIVE UNDER THIS CONSTRUCT?

A. In return for such treatment, the CAISO proposes that the qualifying IBAA Entities should be required to use a unique CAISO Contract Reference Number ("CRN") to schedule all imports to the CAISO at Tracy that utilize the COTP to serve the entities' load within the CAISO BAA . The CAISO also proposes that it would be appropriate for the parties to provide to the CAISO, on a confidential basis, information regarding all schedules on the COTP, not just schedules that support interchange transactions with the CAISO or not just schedules that use the CAISO Controlled Grid. In order for such information to be useful to the CAISO, the CAISO seeks to receive such schedules before 10 AM of the day before the operating day for which those schedules are intended to apply. The CAISO requires the schedules by that time so that it could use such information in its Day-Ahead and Real-Time market processes for purposes of calculating congestion and losses on the CAISO transmission system. COTP schedules that are not using the CAISO Controlled Grid to sink to load in the CAISO will be used for model accuracy enhancement and possible monitoring of the IBAA approach but would not be subject to any CAISO charges.

Q. WHAT OTHER REQUIREMENTS DOES THE CAISO BELIEVE ARE APPROPRIATE UNDER THIS ARRANGEMENT?

A. We believe that it is appropriate to not allow for the application of the methodology for calculation loss exemption s described above during any period in which the IBAA entity is simultaneously using COTP to import power to serve load with the CAISO Controlled Grid and scheduling exports from the CAISO transmission system, at Tracy or any other scheduling point.

Q. WHY DO YOU BELIEVE SUCH A CONDITION IS WARRANTED?

A. The CAISO believes that such a condition is warranted because TANC and TANC members have supported their need for an alternative pricing arrangement on their use of the COTP to serve their load both on and off the CAISO system. Therefore, a reasonable condition of the alternative pricing arrangement is that while using the COTP and the CAISO Controlled Grid to serve their load and receiving the alternative pricing under the agreement, they should not be simultaneously using the CAISO Controlled Grid to sell to other entities. The CAISO recognizes that TANC members may own generation within the CAISO BAA that is used to serve their own loads outside the CAISO BAA, which does not constitute sales to other entities. The CAISO intends to develop appropriate provisions to accommodate such use of generation owned by TANC members to serve their own loads.

Q. WHY DID THE CAISO NOT PROVIDE A COUNTERPROPOSAL TO ADDRESS THE CONGSTION COMPONENT OF LMPS AT THE SCHEDULING POINTS USING THE SINGLE HUB APPROACH MAPPED BACK TO CAPTAIN JACK?

A. The CAISO does not believe that it is necessary to address congestion costs in this proposal, which is primarily targeted to addressing the issues raised by the TANC members regarding the impact of the IBAA proposal on their use and perceived value of the COTP. First, as a general matter, the CAISO does not anticipate significant flow based congestion on the 500kV lines that make up the Pacific AC Intertie ("PACI") portion of the COI based on the fact that the established scheduling limit resulting from the coordinated Western Electricity Coordinating Council ("WECC") path rating process is being enforced. Therefore, as long as the CAISO is operating within path rating, congestion on the 500kV system between the Malin and Tesla substations should be minimal. Similarly, as long as the COTP is operated within its established path rating and related scheduling limit, congestion on the 500kV system between the Captain Jack and Tracy substations should be minimal. However, although the WECC path rating studies consider the impact on underlying transmission systems (230 kV and below), there may be transmission congestion on these underlying systems due in part to schedules on the PACI and COTP, as well as other schedules on the CAISO transmission system. Therefore, consistent with the CAISO IBAA proposal, the CAISO believes it is necessary and appropriate to evaluate the impact of imports on congestion on the entire CAISO grid, including the underlying transmission systems connected with the COI, and to value such imports that are using the CAISO Controlled Grid to service load in the CAISOs based on injections at both Malin and Captain Jack. To the extent schedules/bids to use PACI rights exceed the scheduling limit on PACI, there will be no effect on the congestion component of the schedules that are using COTP. Therefore, schedules on COTP will not be affected by binding congestion on the PACI scheduling limit.

Second, the CAISO provides mechanisms by which IBAA Entities that utilize the COTP to serve load on the CAISO system can substantially hedge their congestion cost exposure. In instances where IBAA Entities serve load within the CAISO BAA through ETCs, the CAISO exempts the ETC schedules from congestion charges through the established “perfect hedge” mechanism. In other instances where IBAA Entities serve load within the CAISO BAA using CRRs, the IBAA Entities will be able to request CRRs sourced at Captain Jack and sunk to load on the CAISO system, thus providing a hedge against potential transmission congestion costs on the CAISO system (including both the 500kV and underlying 230kV systems referred to above). Therefore, the CAISO believes that, when combined with the mechanisms (ETCs and CRRs) already available, the proposal outlined above substantially addresses the major cost concerns (losses) expressed by IBAA Entities with respect to their use of their rights on the COTP to serve load on the CAISO system.

Q. WHAT IS A MARKET EFFICIENCY ENHANCEMENT AGREEMENT?

A. A Market Efficiency Enhancement Agreement or MEEA is an agreement between the CAISO and another BAA or entity within another BAA that provides increased benefits or provides protection to the users of the CAISO Controlled Grid. The other BAA or entity within another BAA provides additional data or information to the CAISO that it can use to improve the modeling accuracy of its models and market system solutions or validate the source and expected operation of the sources supporting scheduled interchange between the IBAA and the CAISO. In exchange for such data, the party to the agreement will receive a price representing an alternative pricing location rather than the default modeling and pricing established under by the CAISO IBAA proposal.

Q. WHAT PROCESS WILL THE CAISO UTILIZE TO ADOPT A MARKET EFFICIENCY ENHANCEMENT AGREEMENT?

A. Based on the market participants request, the CAISO will determine whether the market participant qualifies for such an agreement based on either a demonstration that it owns or controls the resources associated with the pricing point in question, or an evaluation that the data or information it proposes to provide the CAISO will provide benefits to the CAISO and its customers and whether such benefits warrant the requested alternative pricing arrangement. Further, the CAISO will also consider the extent to which the data provided can be used to validate the location and operation of the source supporting scheduled interchange transactions scheduled by the requesting party of the MEEA and the CAISO. The proposed terms of these agreements will be posted and made available for stakeholder comment.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS?

A. Overall, we conclude that it is likely that there will be significant adverse effects on the CAISO's ability to manage congestion at the interties through the LMP-based markets if the CAISO were to continue to model the SMUD and TID BAAs in a radial manner. We believe that the adoption of the SMUD and TID IBAA, the proposed modeling and pricing mechanisms and other associated IBAA changes will best support the following important objectives of MRTU: (1) feasible forward market schedules; (2) more effective congestion management solutions that will reduce uplift costs and other market inefficiencies; and, most importantly, (3) eliminate inappropriate scheduling incentives and pricing signals likely to result if the IBAA modeling and pricing mechanisms are not aligned. It is important to understand that it is the combination number of interconnections, the distances between the different interconnections and the fact that some of the interconnections are not related to any specific resources that creates the scheduling and pricing inefficiencies and potential for reliability problems related to large differences between modeled flows and actual flows.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment A

Diagram 1

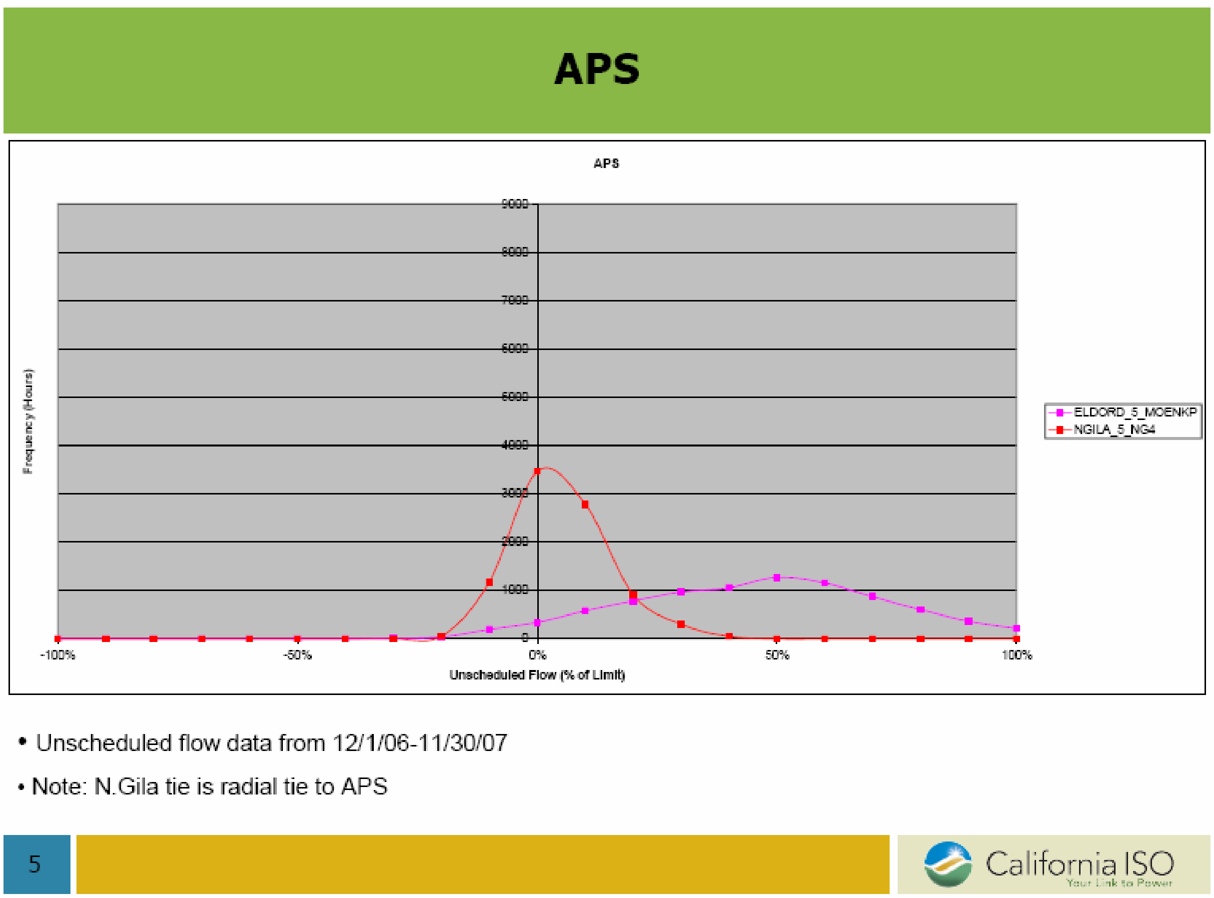
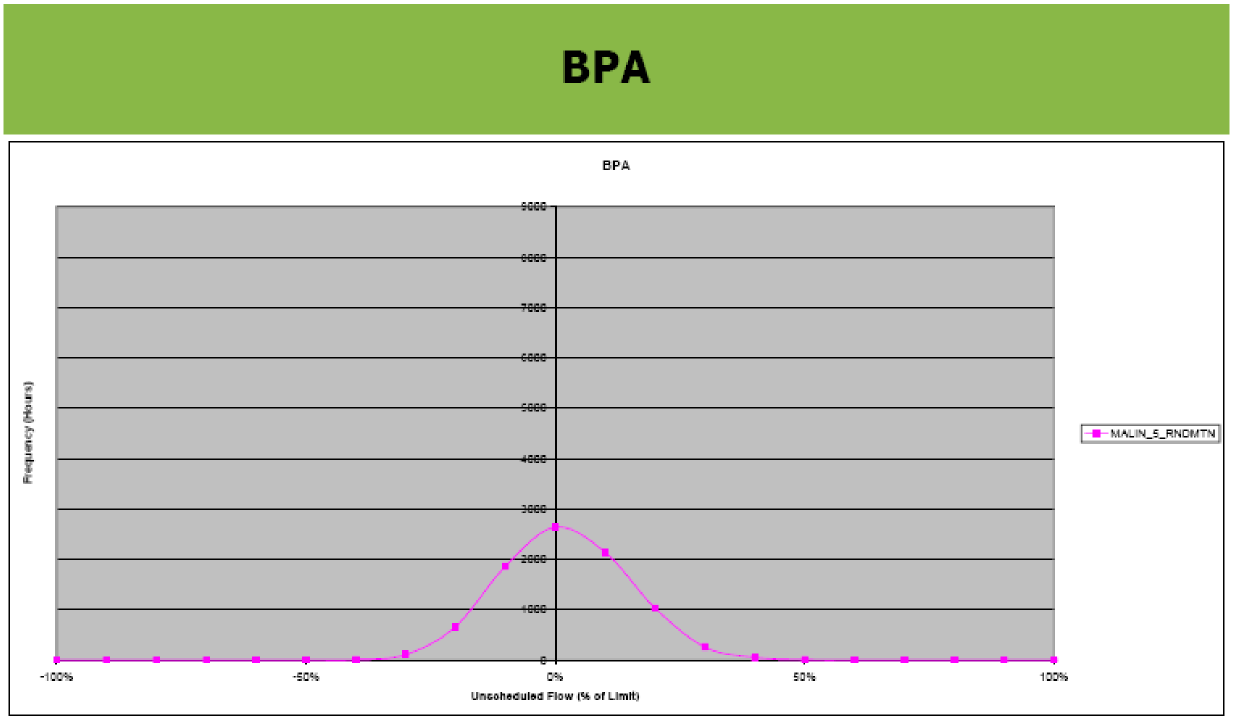
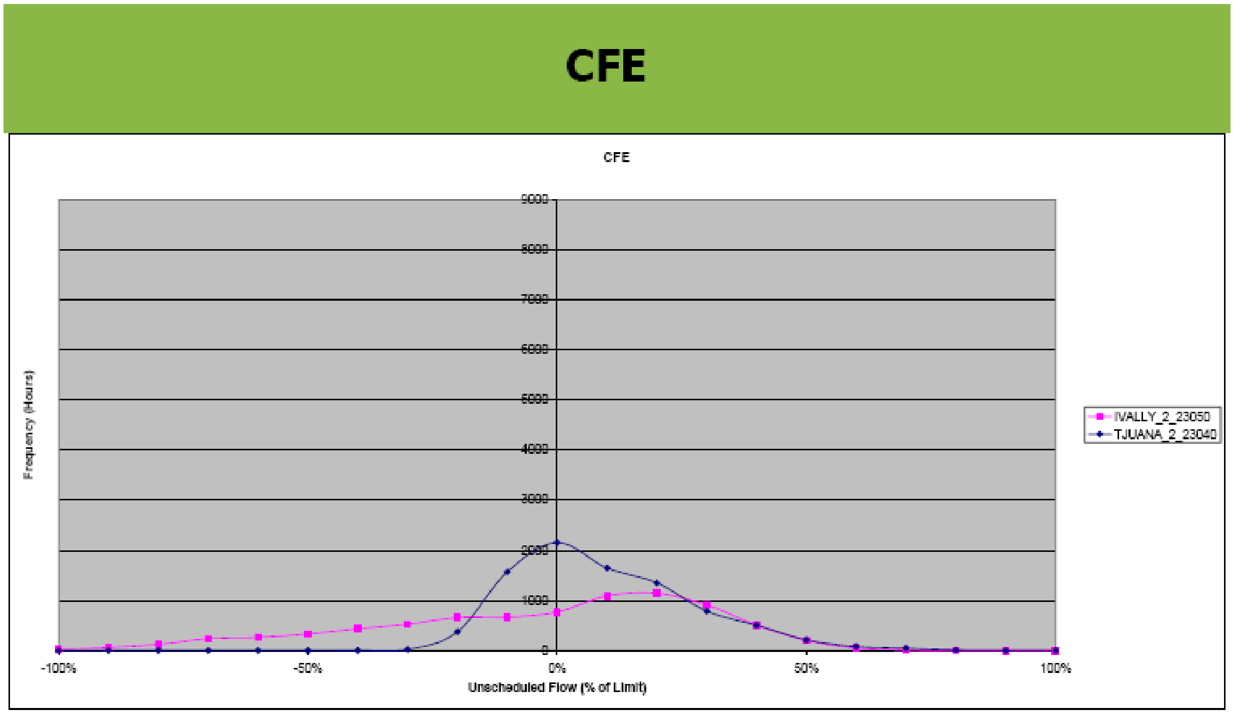


Diagram 2



• Unscheduled flow data from 12/1/06-11/30/07

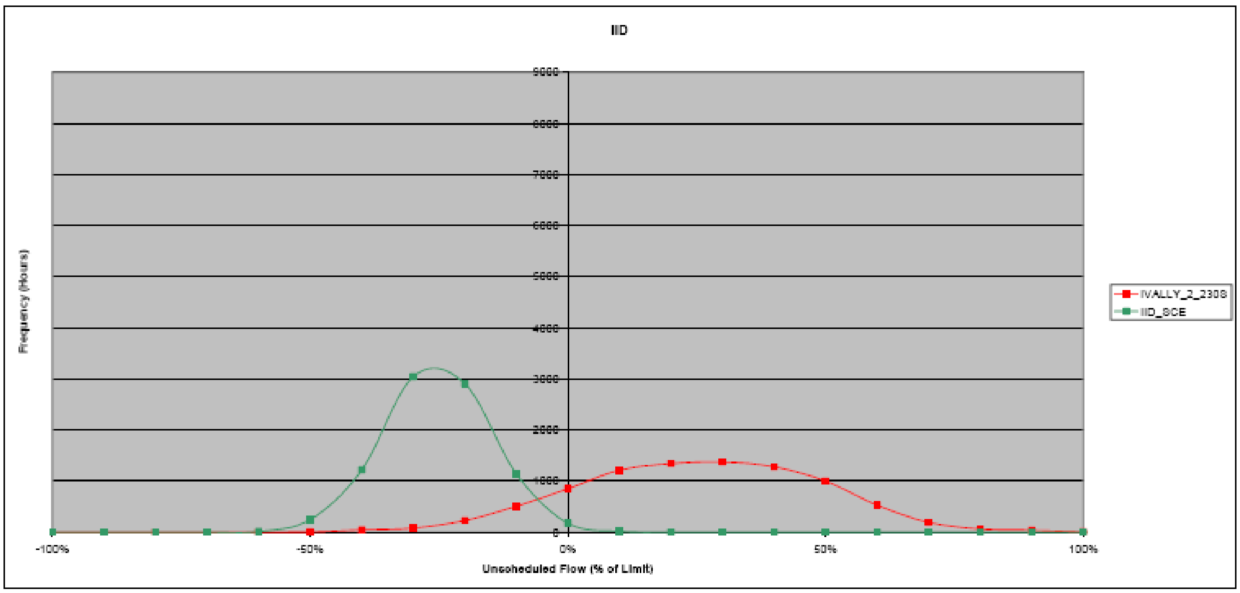
Diagram 3



- Unscheduled flow data from 12/1/06-11/30/07

Diagram 4

IID



- Unscheduled flow data from 12/1/06-11/30/07

Diagram 5

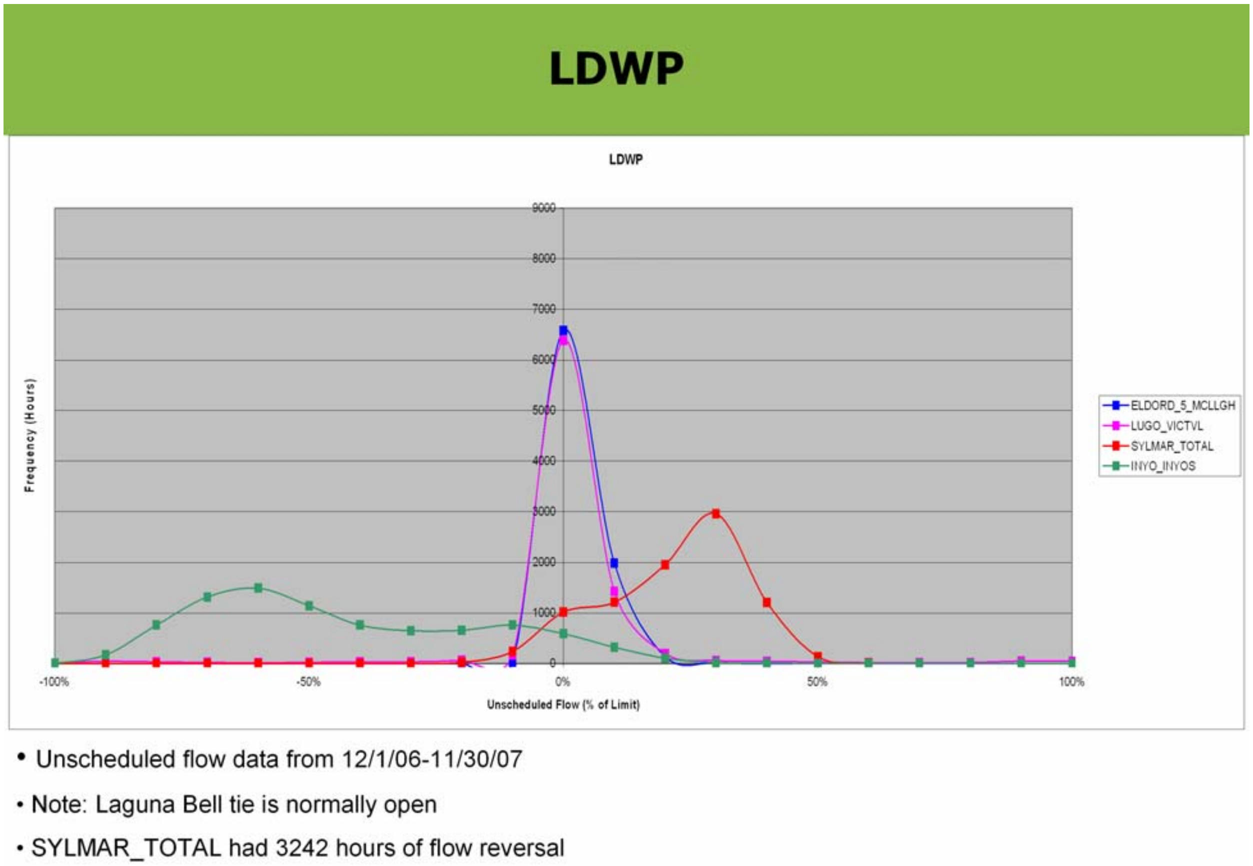
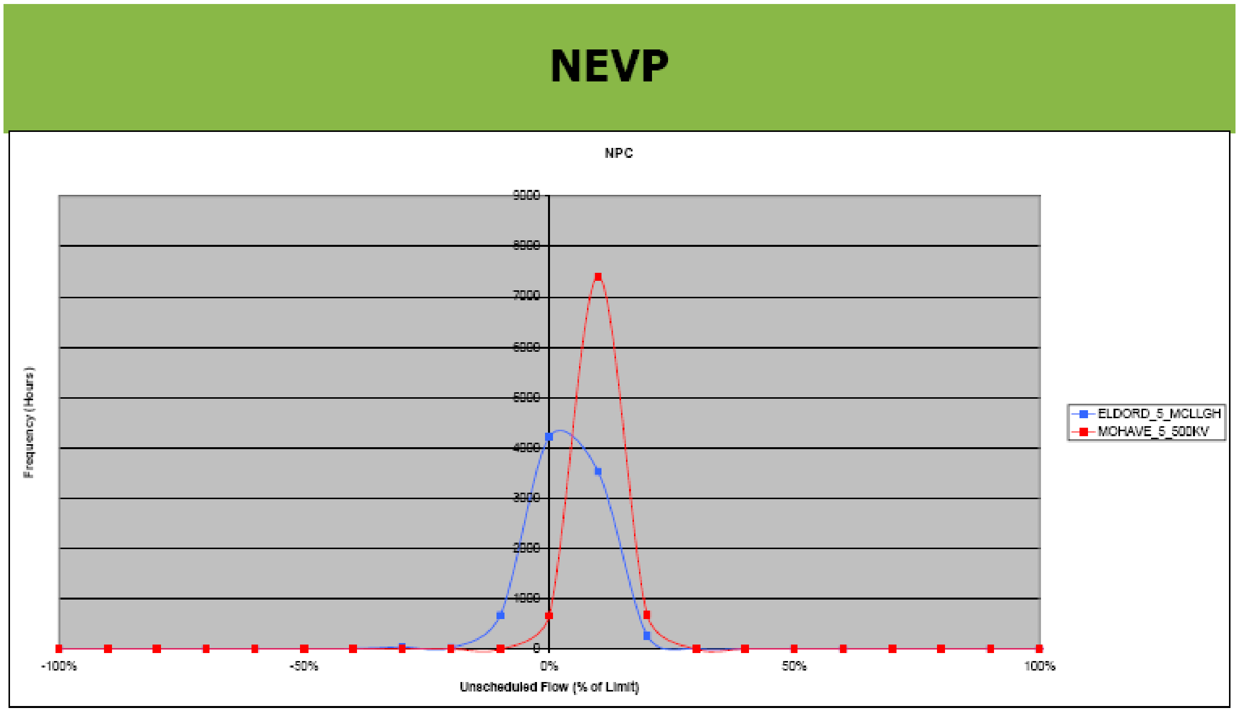
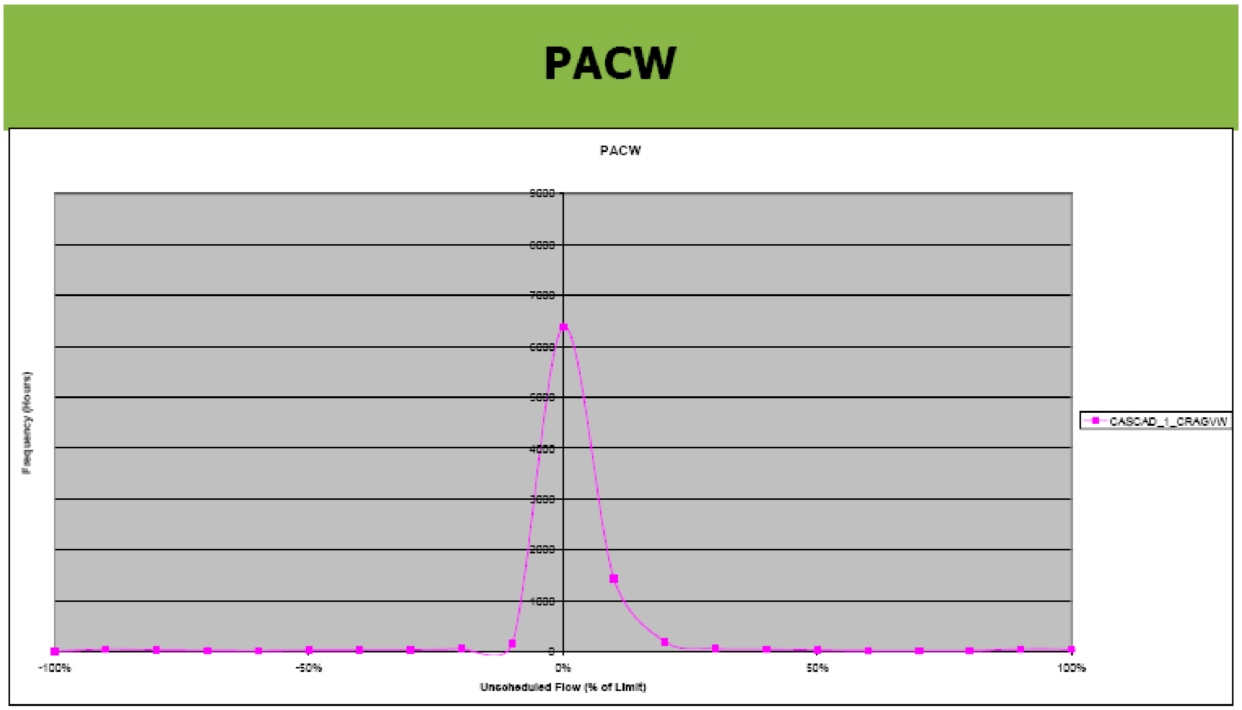

LDWP
LDWP
Frequency (Hours)
Unscheduled Flow (% of Limit)
ELDORD_5_MCLLGH
LUGO_VICTVL
SYLMAR_TOTAL
INYO_INYOS
• Unscheduled flow data from 12/1/06-11/30/07
• Note: Laguna Bell tie is normally open
• SYLMAR_TOTAL had 3242 hours of flow reversal

Diagram 6



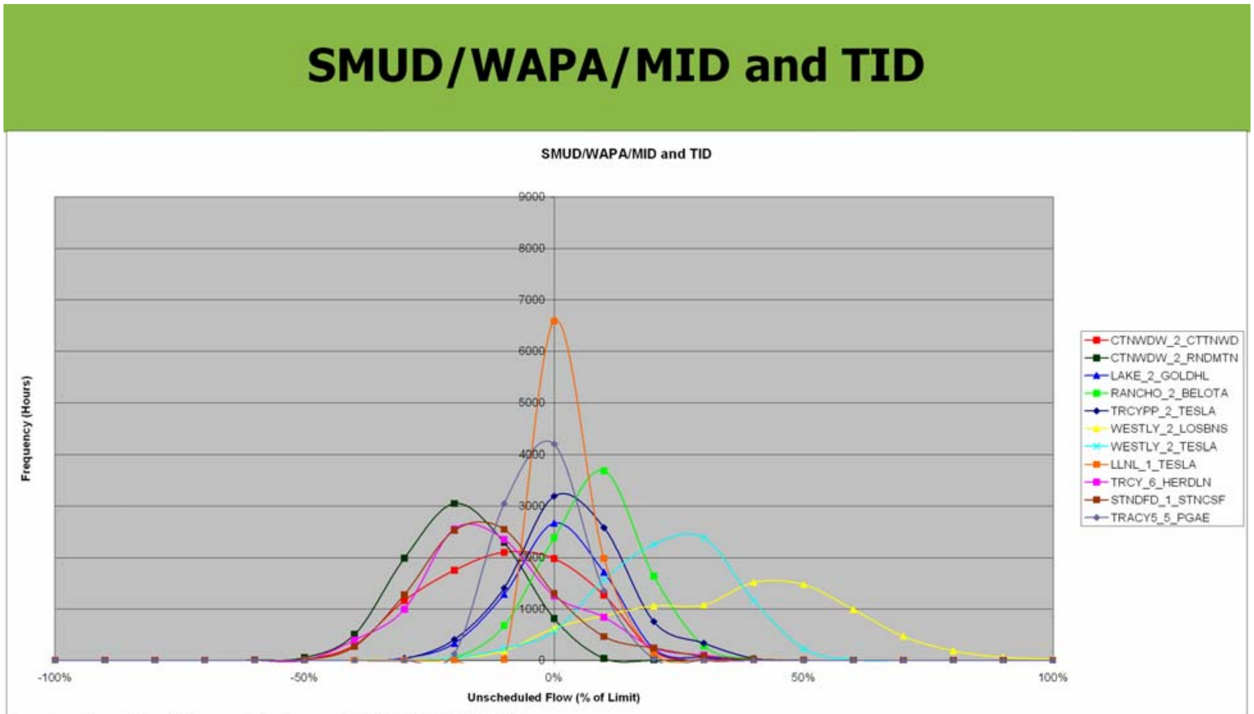
- Unscheduled flow data from 12/1/06-11/30/07

Diagram 7



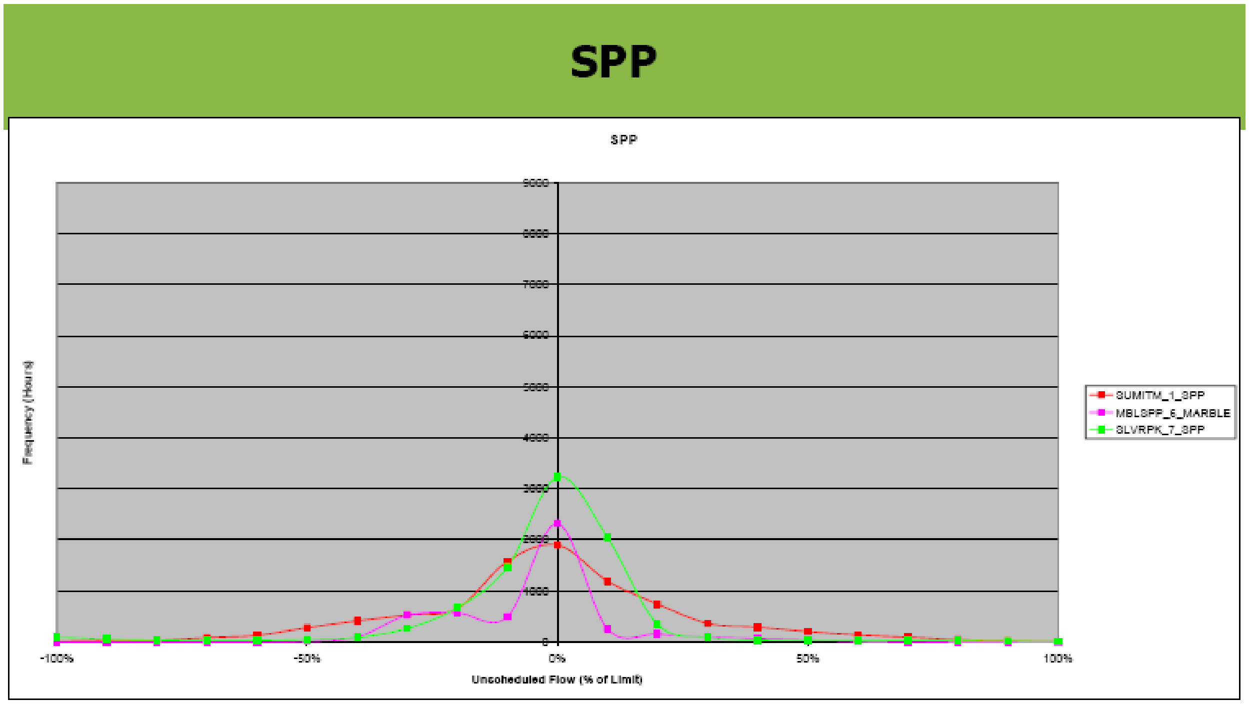
• Unscheduled flow data from 12/1/06-11/30/07

Diagram 8



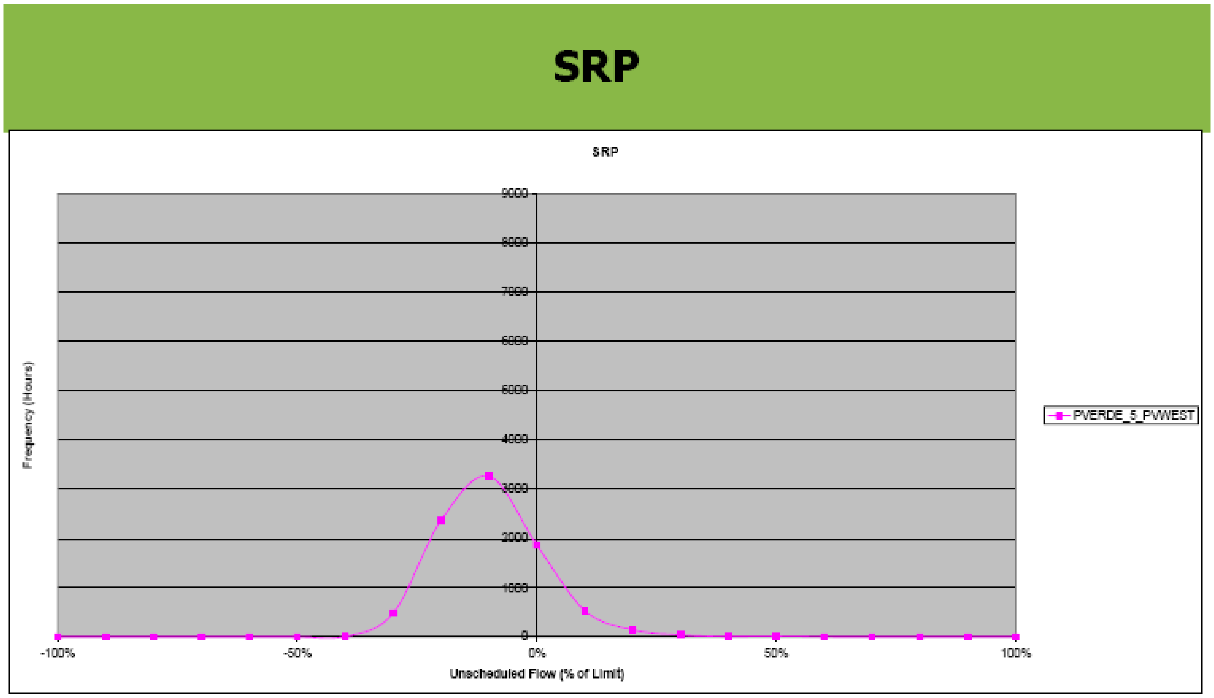
- Unscheduled flow data from 12/1/06-11/30/07
- Note: Oakdale actual data unavailable
- CTNWDW_2_CTTNWD had 6369 hours of flow reversal
- TRACY_PGAE includes adjustment for Sutter actual

Diagram 9



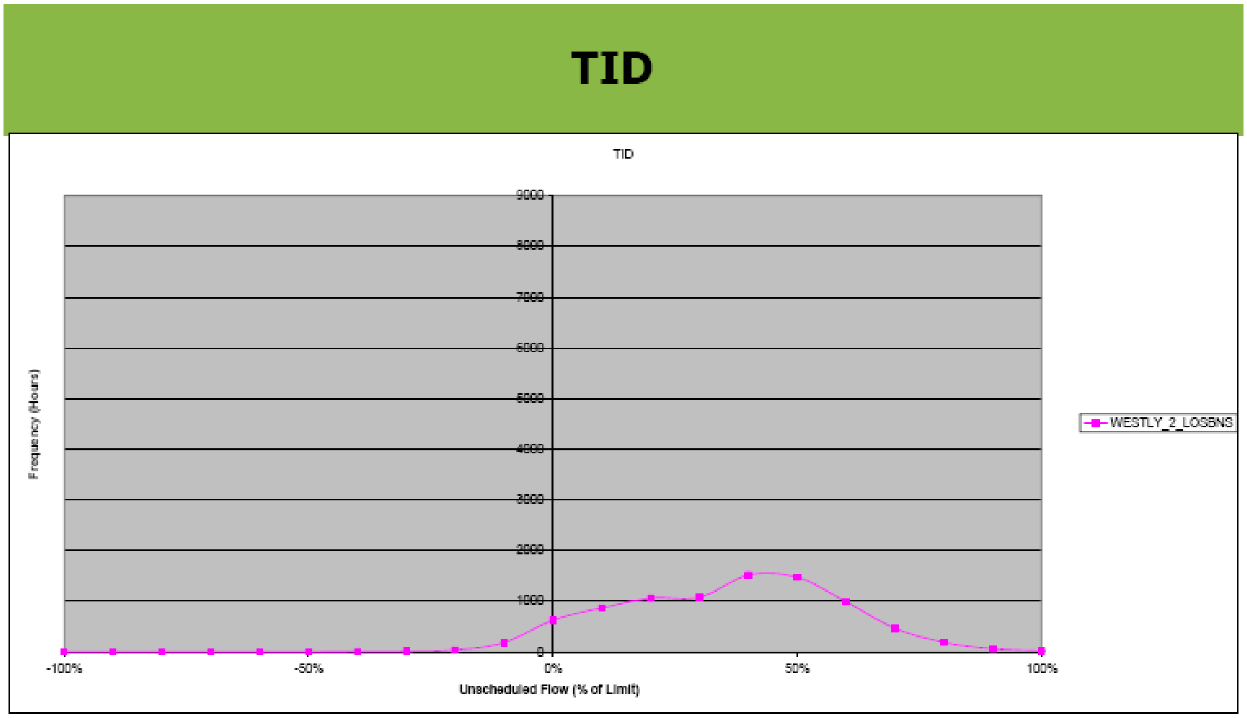
- Unscheduled flow data from 12/1/06-11/30/07

Diagram 10



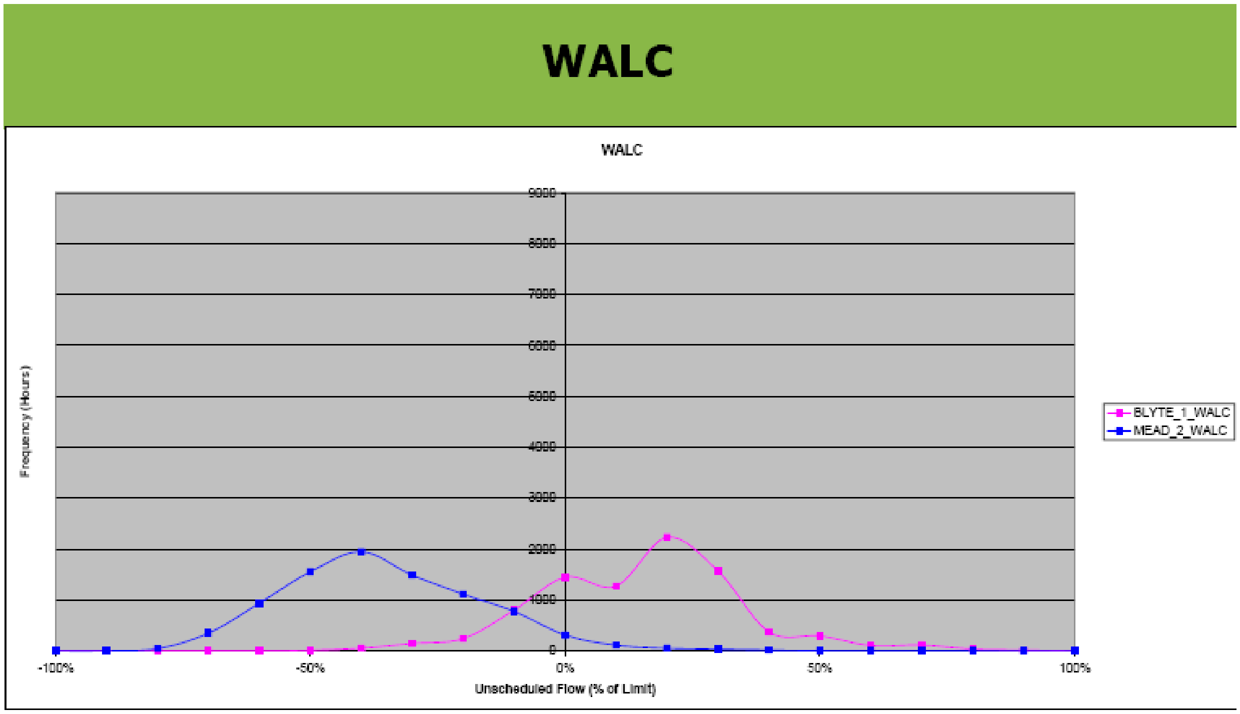
- Unscheduled flow data from 12/1/06-11/30/07
- PVERDE_5_PVWEST had 0 hours of reversal

Diagram 11



- Unscheduled flow data from 12/1/06-11/30/07
- Note: Oakdale actual data unavailable

Diagram 12



- Unscheduled flow data from 12/1/06-11/30/07
- Note: Parker data unavailable

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER08-___-000**

I, Mark Rothleder, declare under penalty of perjury, that the foregoing questions and answers labeled as the Testimony of Mark Rothleder and James E. Price were prepared by us, with the assistance of others working under our direction and supervision; and that the facts contained in those answers are true and correct to the best of my knowledge, information and belief.

Executed on: 6/12/08
Date

Mark Rothleder

(California Notarial Acknowledgment Attached)

State of California)
)
County of Sacramento)

On June 12, 2008, before me, Martha M. Sedgley, Notary Public,

personally appeared Mark Rothleder,

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

MARTHA M. SEDGLEY
COMM. #1690762
Notary Public-California
PLACER COUNTY
My Comm. Exp. Sep. 27, 2010
BMP1

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Martha M. Sedgley
Notary Public

WDC01/229173v1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER08-___-000**

I, James E. Price, declare under penalty of perjury, that the foregoing questions and answers labeled as the Testimony of James E. Price and Mark Rothleder were prepared by us, with the assistance of others working under our direction and supervision; and that the facts contained in those answers are true and correct to the best of my knowledge, information and belief.

Executed on: 6/12/2008
Date

James E Price
James E. Price

(California Notarial Acknowledgment Attached)

State of California)
)
County of Sacramento)

On June 12, 2008, before me, Martha M. Sedgley, Notary Public, personally appeared James E. Price,

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

MARTHA M. SEDGLEY
COMM. #1690762
Notary Public-California
PLACER COUNTY
My Comm. Exp. Sep. 27, 2010
BMP1

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Martha M. Sedgley
Notary Public

WDC01/229173v1

Attachment G

Exhibit No. ISO-2 - Testimony of Dr. Eric Hildebrandt

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER08-___-000**

PREPARED DIRECT TESTIMONY
OF
DR. ERIC HILDEBRANDT ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

June 17, 2008

SUMMARY OF THE TESTIMONY OF DR. ERIC W. HILDEBRANDT

Dr. Eric W. Hildebrandt is the Manager of Analysis and Mitigation in the Department of Market Monitoring ("DMM") of the California Independent System Operator Corporation ("CAISO"). Since joining DMM, Dr. Hildebrandt has worked extensively on a wide range of issues involving analysis of market performance, behavior of Market Participants, and design of market rules that promote market efficiency and deter potential detrimental market behavior.

With respect to the CAISO's Integrated Balancing Authority Area ("IBAA") proposal, Dr. Hildebrandt testifies as to DMM's review of the sub hub (or multiple hub) approach initially proposed by the CAISO and the specific concerns and potential for ineffective market rules that were identified under this approach. He explains the informational requirements that DMM identified the CAISO would require as being necessary under this sub hub approach to help ensure schedules are consistent with the actual congestion relief. Finally, he explains how the single hub approach contained in the CAISO's filing addresses DMM's concerns with the sub hub approach that exist in the absence of more detailed information from external Balancing Authority Areas.

The approach initially proposed by the CAISO in the IBAA stakeholder process called for the creation of six different sub hubs for the Sacramento Municipal Utility District ("SMUD") and Turlock Irrigation District ("TID") IBAAs. All import and export schedules submitted at the existing Intertie Scheduling Points between the CAISO and the SMUD and TID IBAAs would then be mapped to one of these six sub hubs. Import and export schedules and bids would be settled based on the Locational Marginal Price ("LMP") for the sub hub to which each schedule was mapped based on the specific Resource ID under which the participant submitted the schedule or bid. The proposal was aimed at improving the reliable and cost-effective management of congestion on the CAISO Controlled Grid by more accurately modeling the impact of import and export schedules and bids submitted by Market Participants on different inter-ties between the CAISO and the SMUD and TID IBAAs by approximating the marginal impact of these schedules and bids on flows on the CAISO Controlled Grid.

As Dr. Hildebrandt states, under the LMP-based markets being implemented under the CAISO's MRTU program, the location of the resources supporting a given interchange transaction is critically important for the CAISO to reliably and cost-effectively manage congestion on the CAISO Controlled Grid.[1]

Dr. Hildebrandt explains the concerns identified by DMM with the sub-hub proposal: Importantly, while the potential congestion management benefits of the sub hub approach depend entirely on having an accurate representation of the marginal System Resource actually supporting the import and export schedule and bids submitted by Market Participants, the natural economic behavior for Market Participants would be to submit their bids at ISPs using Resource IDs that are mapped to System Resources with the highest price (for import sales to the CAISO) or the lowest price (for export purchases from the CAISO). Such pricing incentives tend to encourage market behavior that could negate the intended accuracy and congestion management benefits of the CAISO's proposed methodology and impose additional costs associated with such inaccuracies on CAISO Market Participants.[2] In addition, DMM is concerned that under the sub-

[1] For example, during a typical period of north-to-south congestion between Northern California and the Pacific Northwest, a schedule or bid associated with an increase in output from a generating plant in the SMUD sub hub could provide significant congestion management benefits, while a schedule or bid associated with an increase in imports from the Northwest on the California-Oregon Transmission Project ("COTP") or other elements of the California Oregon Intertie ("COI") could exacerbate congestion on the CAISO Controlled Grid.

[2] Dr. Hildebrandt cites the following example: During a period of north-to-south congestion, as described in my previous example, LMPs would tend to be higher for import schedules mapped to the SMUD or Western or sub hubs than for imports mapped to the Captain Jack sub-hub. This is a consequence of the fact that during periods of

hub approach there still exists an incentive for Market Participants to create sets of "circular" import and export schedules or transactions that would require the CAISO to "sell low" and "buy high."[3] Therefore, absent additional information and data provided by the external BAA, the CAISO would have a limited ability to monitor and ensure that the resources (System Resources) purportedly supporting scheduled import and export transactions accurately represented the approximate location of the actual resources supporting these scheduled transactions. Given that without the additional data the modeling benefits of the sub-hub approach cannot materialize, it is compelling to mitigate further for the "circular" import/export concerns identified by Dr. Hildebrandt, Dr. Harvey and the Market Surveillance Committee.

As a result, Dr. Hildebrandt and DMM recommend that if the CAISO adopted the sub-hub approach, a number of protections should be included in the proposal.

- That the CAISO include scheduling and informational requirements applicable to all individual transactions between the CAISO and any of the sub-hubs.

---

north-to-south congestion, generation located within the SMUD or Western sub hubs is more effective in relieving this congestion because it creates a counter flow to such congestion, and is therefore more valuable to the CAISO. Conversely, import transactions sourced from resources in the Pacific Northwest and scheduled at Captain Jack would exacerbate north-to-south congestion. This circumstance – higher prices at the SMUD or Western sub-hubs, coupled with lower prices at the Captain Jack sub hub – would create an incentive for any additional supplies from the Northwest being imported on COTP to ultimately be scheduled as imports from the SMUD or Western sub-hubs. In addition to requiring that CAISO Market Participants overpay for these import relative to their impact on congestion within eh CAISO system, this could exacerbate congestion within the CAISO system in real time, and thereby require the CAISO to redispatch other resources and incur additional redispatch costs in the CAISO's real time market.

[3] Building on the example in the prior footnote, energy might be exported (i.e., bought) from the CAISO using Resource IDs mapped to a lower priced sub hub (such as Captain Jack), and this energy may then be used – directly or indirectly – to support an import (i.e., sold) to the CAISO using a Resource ID mapped to a higher priced sub hub (such as the SMUD or Western sub hub). Another variation of such circular scheduling patterns would be that exports at the Malin inter-tie from CAISO into the Bonneville Power Authority ("BPA") might be used – directly or indirectly – to support additional imports into the SMUD IBAA at Captain Jack, which could then in turn be used to support additional imports back into the CAISO via schedules mapped to a higher priced sub hub within the SMUD and TID IBAA (such as SMUD or Western).

- That any Market Efficiency Enhancement Agreements established specify additional information that may be requested by the CAISO, such as (a) metered generation data for any generating resource under the SC's control within the applicable sub-hub(s), and (b) information on bilateral trades and schedules to and from other Market Participants within the SMUD and TID IBAAs so that the CAISO could evaluate and verify the source supporting schedules from the various sub-hub; and

- That the CAISO explicitly reserve the authority and establish the software capability necessary to quickly switch to a single hub approach if the CAISO believed that any of the concerns with the sub-hub proposal materialized.

DMM is concerned that relying on "behavioral" market rules[4] would be insufficient if anomalous market behavior was detected. First, it would require an extensive monitoring and investigation effort by DMM and any potential violations would need to be referred to FERC's Office of Enforcement. Moreover, participants do not have to intentionally misrepresent the actual location of the resources in the circular schedule problem – rather, Dr. Hildebrandt testifies that the differences in LMPs for the different sub-hubs would create an incentive for bilateral trading between different participants that would have the same end result.

Dr. Hildebrandt also explains how the CAISO's final proposal: (1) respects DMM's proposed informational requirements, in the form of a provision for developing alternative pricing arrangements with individual participants on a case-by-case basis, subject to specific pre-agreed requirements for information and verification; and (2) addresses the concerns over improper pricing incentives by adopting a single hub approach.[5]

---

[4] For example, behavior that was inconsistent with the intent of the scheduling rules that would apply under the sub-hub approach could be subject to provisions of the MRTU tariff prohibiting the submission of "false or misleading information" to the CAISO (Section 37.5 of the CAISO Tariff) and prohibiting market manipulation, which includes "any device, scheme or artifice to defraud" (Section 37.7). FERC market rules similarly prohibit provision of false information to a system operator (18 CFR § 35.37 (b) Communications) and market manipulation (18 C.F.R. § 1c.2 Prohibition of Electric Energy Market Manipulation).

[5] Under the single hub approach, the default price paid for all imports scheduled from the SMUD and TID IBAA into the CAISO will be based on the LMP at the Captain Jack substation, while the default price for all exports from the CAISO will be based on the cost of a decrease in generation at the SMUD Aggregate System

Finally, Dr. Hildebrandt explains why the counter proposal provided by the IBAA entities during the stakeholder process does not meet the CAISO's market needs and oversight responsibilities. First, he notes that the IBBA entities' counter proposal only calls for the CAISO and IBAA entities to form a joint review committee to "collaboratively develop and implement processes regarding the market behaviors that would be monitored," which could include "an ongoing interbalancing area operations committee with market surveillance oversight responsibilities." However, nothing in the IBAA entities' counter proposal would explicitly or implicitly prohibit the type of scheduling behavior of concern to DMM. On the contrary, the counter proposal is specifically designed to ensure that Market Participants have the ability to schedule imports and exports at ISPs where prices would be most favorable to them, without any requirements or consideration as to the actual source of the generation supporting these schedules. Second, Dr. Hildebrandt notes that the proposal calls only for the IBAA entities to "work collaboratively with the CAISO to develop a mutually agreeable and reciprocal process for developing, securing and sharing historic generation data" and that any data under such an agreement would be shared "on a reciprocal, after-the-fact basis" and would not be allowed to be removed from each other's sites. Dr. Hildebrandt testifies that this proposal is fundamentally insufficient with respect to the data requirements needed to address the market monitoring concerns of the CAISO. He specifies that it does not provide supporting data to the CAISO in a

---

Resource, as represented by the LMP calculated for the SMUD hub. This default pricing rule eliminates the incentive for a participant to misrepresent or somehow disguise the source of any additional supply at a lower priced System Resource (such as Captain Jack or Western) as an import from a higher priced System Resource (such as SMUD). Since LMPs will tend to be lower at the Captain Jack System Resource than at the SMUD Aggregate System Resource during periods of north-to-south congestion, this default settlement rule will also eliminate the potential for circular import /export scheduling patterns that would force the CAISO to "buy high" and "sell low," without any congestion management benefits to the CAISO system.

manner that allows timely and objective verification by the CAISO of the resources supporting scheduled import and export transactions.

.

I. INTRODUCTION & OVERVIEW

A. EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Eric W. Hildebrandt. I am employed by the California Independent System Operator Corporation ("CAISO") located at 151 Blue Ravine Road, Folsom, California 95630.

Q. DR. HILDEBRANDT, WHAT ARE YOUR CURRENT RESPONSIBILITIES AT THE CAISO?

A. I currently serve as Manager of Analysis and Mitigation in the CAISO's Department of Market Monitoring ("DMM"). I am responsible for analyzing performance of the CAISO markets, assessing the impact of market rules and behavior of Market Participants on market performance, investigating potential non-compliance with CAISO and FERC market rules, and helping to design market rules that promote overall market efficiency, mitigate market power and deter detrimental market behavior. In this capacity, I have worked with other CAISO staff to help design and assess various options for how transactions between the CAISO and neighboring Balancing Authority Areas should be modeled and priced under the CAISO's Market Redesign and Technology Upgrade ("MRTU") program.

Q. PLEASE DESCRIBE YOUR PRIOR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I have twenty years of experience in the electric utility industry, along with a B.S. degree in Political Economy from Colorado College, and an M.S. and a Ph.D. in Energy Management and Policy from the University of Pennsylvania.

I began my career in the energy industry as a Research Associate at the Center for Energy and Environment at the University of Pennsylvania in 1988, and worked for over six years as an economic consultant to the electric utility industry through the consulting firms of Xenergy Inc. and Hagler Bailly Consulting. I then worked for over three years at the Sacramento Municipal Utility District ("SMUD") as Supervisor of Monitoring and Evaluation.

Since joining the CAISO's Department of Market Monitoring in 1998, I have worked extensively on a wide range of issues involving analysis of market performance, behavior of Market Participants, and design of market rules that promote market efficiency and deter potential detrimental market behavior. During California's Energy Crisis of 2000-2001, I played a lead role in analyzing market conditions and behavior in California's wholesale energy markets, and developing market design options for addressing the wide range of problems occurring during this period. In the aftermath of this crisis, I worked extensively as the CAISO's lead investigator on a wide range of investigations and other regulatory proceedings relating to the market behavior of individual participants in California's wholesale energy markets. In this capacity, I performed extensive analysis to identify scheduling and trading practices that may have constituted abuse of market power, manipulation, gaming or other anomalous market behavior inconsistent with CAISO market rules or competitive efficient markets. Over the last five years, I have played a lead role in developing and implementing new FERC and CAISO market rules to prevent or address such detrimental market behavior in the future. During this period, I have also led the CAISO's efforts to monitor and investigate potential non-compliance with CAISO and FERC behavioral market rules, and to refer potential violations of these rules to the Commission's Office of Enforcement.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE COMMISSION?

A. Yes. I have provided testimony on behalf of the CAISO in the Commission's proceedings concerning gaming and market manipulation in the California wholesale electric markets (Docket No. EL03-137-000 *et al)*, and in the so-called "100 Days Evidence" proceeding (Docket Nos. EL05-05-069 and EL00-98-042). I also provided testimony on behalf of the CAISO in the proceeding concerning refunds for transactions in the California wholesale electric markets (Docket Nos. EL00-95-000, *et. al*), as well as affidavits and analysis in support of the CAISO's efforts to mitigate the market failures during the California Energy Crisis of 2000-01. During 1999, I provided testimony in proceedings related to RMR contracts in California (Docket Nos. ER98-496-000, ER98-1614-000, ER2145-000 and ER99-3603). While working at the CAISO, I have also submitted affidavits and analysis to Commission staff in conjunction with numerous confidential investigations of market behavior.

Q. AS YOU TESTIFY, WILL YOU BE USING ANY SPECIALIZED TERMS?

A. Yes. I will use capitalized terms as defined in the Master Definitions, Appendix A of the CAISO Tariff.

B. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the CAISO's application to implement its Integrated Balancing Authority Area ("IBAA") proposal. In particular, I will testify as to DMM's review of the *sub hub* (or *multiple hub*) approach initially proposed by the CAISO and the specific concerns and potential for ineffective market rules we identified under this approach. I will explain some of the informational requirements that DMM identified as being necessary under this sub hub approach to help ensure schedules are consistent with the actual congestion relief sought by the CAISO. Finally, I will explain how the single hub approach contained in the CAISO's filing addresses DMM's concerns with the sub hub approach that exist in the absence of more detailed information from external Balancing Authority Areas.

II. TESTIMONY

Q. PLEASE EXPLAIN DMM'S ROLE WITH RESPECT TO THE EVALUATION OF THE CAISO'S IBAA PROPOSAL

A. DMM's role in the CAISO's process for developing its IBAA proposal was primarily to review the pricing provisions of the various options under consideration, and assess the incentives that the resulting prices may have on scheduling behavior of participants and overall market efficiency. DMM also provided recommendations for specific market rules that might be established to mitigate DMM's concerns about potential detrimental market behavior or market inefficiencies that may exist under various modeling and pricing options.

Q. WHAT WAS THE CAISO'S INITIAL PROPOSAL WITH RESPECT TO MODELING AND PRICING OF INTEGRATED BALANCING AUTHORITY AREAS?

A. As described in the CAISO's December 14, 2007, "Discussion Paper – Modeling and Pricing Integrated Balancing Authority Areas Under the California ISO's Market Redesign and Technology Upgrade Program" ("*Modeling & Pricing Discussion Paper*"), the approach initially proposed by the CAISO in the IBAA stakeholder process called for the creation of six different sub hubs for the SMUD and Turlock Irrigation District ("TID") IBAAs.[6] Under this approach, the CAISO would first utilize equivlancing techniques to develop a simplified model of the SMUD and TID IBAAs. This simplified network model would represent the transmission network, generating resources, and loads within these IBAAs in terms of either single or aggregated System Resources. These System Resources would form (or correspond to) six distinct sub hubs: SMUD, Western Area Power Administration ("Western"), Modesto Irrigation District, City of Roseville, TID, and the Captain Jack substation (representing the source of imports from

[6] *See Modeling & Pricing Discussion Paper* at 9. The *Modeling & Pricing Discussion Paper* can be found at http://www.caiso.com/1cb4/1cb4e1a154060.pdf.

the Pacific Northwest).[7] All import and export schedules submitted at the existing Intertie Scheduling Points ("ISPs") between the CAISO and the SMUD and TID IBAAs would then be mapped to one of these six sub hubs based on special Resources Identifiers ("Resource IDs"), which participants must use for scheduling at any of these ISPs. Using these Resource IDs, the network model incorporated in the CAISO's market software would then model imports to the CAISO as positive injections as occurring at the specified sub hub. Similarly, exports from the CAISO would be modeled as decremental or negative changes occurring at the sub hub to which each export schedule was mapped. Under this sub hub approach, import and export schedules and bids would be settled based on the Locational Marginal Price ("LMP") for the sub hub to which each schedule was mapped based on the specific Resource ID under which the participant submitted the schedule or bid.

Q. WHY DID THE CAISO INITIALLY PROPOSE THIS APPROACH?

A. In keeping with the general purpose of the MRTU program, the CAISO's initial sub hub proposal was aimed at improving the reliable and cost-effective management of congestion on the CAISO Controlled Grid. Specifically, the objective of the CAISO's proposal was to more accurately model the impact of import and export schedules and bids submitted by Market Participants on different inter-ties between the CAISO and the

[7] Two of these sub-hubs – SMUD and Western – would be represented by Aggregated System Resources, with injections distributed to the locations/facilities that comprise the Aggregated System Resources pursuant to pre-determined Intertie Distribution Factors. All other sub-hubs would be represented by a single System Resource.

SMUD and TID IBAAs by approximating the marginal impact of these schedules and bids on flows on the CAISO Controlled Grid. Consequently, the resulting LMPs at the applicable ISPs would better reflect the impact of such flows on the CAISO system. To determine the marginal impact of such schedules on flows on the CAISO Controlled Grid, the CAISO proposed to use the Resource ID used by Market Participants to schedule imports and exports as the basis for modeling the location of the *marginal* resources actually supporting such transactions: i.e., the specific generating resources, or dispatchable load whose output was either increased or decreased in the SMUD and TID IBAAs to support or effect the scheduled interchange transaction. Under the LMP-based markets being implemented under the CAISO's MRTU program, the location of the resources supporting a given interchange transaction is critically important for the CAISO to reliably and cost-effectively manage congestion on the CAISO Controlled Grid. For example, during a typical period of north-to-south congestion between Northern California and the Pacific Northwest, a schedule or bid associated with an increase in output from a generating plant in the SMUD sub hub could provide significant congestion management benefits, while a schedule or bid associated with an increase in imports from the Northwest on the California-Oregon Transmission Project ("COTP") or other elements of the California Oregon Intertie ("COI") could exacerbate congestion on the CAISO Controlled Grid. Thus, provided that the Resource IDs for import and export schedules and bids submitted by participants accurately portray the location of resources outside the CAISO whose output would be increased or decreased to support the scheduled interchange schedules or bids, this approach could allow the CAISO to reliably and cost effectively manage congestion on the CAISO Controlled Grid and would establish, consistent with the objectives of the larger MRTU design, LMPs that reflect the value of such imports and exports for purposes of managing congestion on the CAISO Controlled Grid.

Q. DID YOU EVALUATE THE CAISO SUB HUB PROPOSAL?

A. Yes. In collaboration with internal and external experts, including the CAISO's Market Surveillance Committee ("MSC") and Dr. Harvey, I reviewed and evaluated the initial sub-hub proposal and participated in the CAISO's development of the single hub structure. In addition, I participated in the various stakeholder and joint stakeholder/MSC meetings held to evaluate the proposal that ultimately led to the adoption of the single hub approach.

Q. WHAT CONCLUSIONS DID YOU REACH?

A. First, the potential congestion management benefits of the sub hub approach depend entirely on having an accurate representation of the marginal System Resource (e.g., SMUD Hub, Western Hub, Captain Jack, etc.) actually supporting the import and export schedule and bids submitted by Market Participants. As explained further by Dr. Harvey in his testimony, it is natural economic behavior for Market Participants to submit their bids at ISPs using Resource IDs that are mapped to System Resources with the highest price (for import sales to the CAISO) or the lowest price (for export purchases from the CAISO). Such pricing incentives would tend to encourage market behavior that could negate the intended accuracy and congestion management benefits of the CAISO's proposed methodology and impose additional costs associated with such inaccuracies on CAISO Market Participants. For example, during of a period of north-to-south congestion, as described in my previous example, LMPs would tend to be higher for import schedules mapped to the SMUD or Western or sub hubs than for imports mapped to the Captain Jack sub-hub. This is a consequence of the fact that during periods of north-to-south congestion, generation located within the SMUD or Western sub hubs is more effective in relieving this congestion because it creates a counter flow to such congestion, and is therefore more valuable to the CAISO. Conversely, import transactions sourced from resources in the Pacific Northwest and scheduled at Captain Jack would exacerbate north-to-south congestion. This circumstance – higher prices at the SMUD or Western sub-hubs, coupled with lower prices at the Captain Jack sub hub – would create an incentive for any additional supplies from the Northwest being imported on COTP to ultimately be scheduled as imports from the SMUD or Western sub-hubs. In addition to requiring that CAISO Market Participants overpay for these imports relative to their impact on congestion within the CAISO system, this could exacerbate congestion within the CAISO system in real time, and thereby require the CAISO to redispatch other resources and incur additional redispatch costs in the CAISO's real time market.

A second concern that DMM identified through our assessment of the sub hub proposal was there still existed an incentive for Market Participants to create sets of "circular" import and export schedules or transactions that would require the CAISO to "sell low" and "buy high." Again, building upon my previous example, energy might be exported (i.e., bought) from the CAISO using Resource IDs mapped to a lower priced sub hub (such as Captain Jack), and this energy may then be used – directly or indirectly – to support an import (*i.e.*, sold) to the CAISO using a Resource ID mapped to a higher priced sub hub (such as the SMUD or Western sub hub). Another variation of such circular scheduling patterns would be that exports at the Malin inter-tie from CAISO into the Bonneville Power Authority ("BPA") might be used – directly or indirectly – to support additional imports into the SMUD IBAA at Captain Jack, which could then in turn be used to support additional imports back into the CAISO via schedules mapped to a higher priced sub hub within the SMUD and TID IBAA (such as SMUD or Western).

Q. WHY DID YOU BELIEVE THESE ADVERSE CONSEQUENCES WERE LIKELY TO OCCUR UNDER THE SUB HUB APPROACH?

A. While DMM supported the CAISO's objective of capturing the intended potential congestion management benefits of the sub-hub approach, DMM was concerned that the sub-hub proposal would be subject to abuse because the proposal was dependent on Market Participants accurately identifying the marginal resources that would actually support their scheduled interchange transactions. However, as described above, LMPs established under this proposal would create an incentive for participants to misrepresent the actual location of the marginal resource(s) supporting the scheduled transaction. Moreover, even if participants did not intentionally misrepresent the actual location of the resources supporting intertie schedules or create "circular" import and export schedules, differences in LMPs for these different sub-hubs would create a definite incentive for bilateral trading between different participants that would have the same end result. For example, one participant may purchase an export from the CAISO at a low priced sub-hub, while making a sale at a higher-priced sub-hub to another participant. This transaction could then enable this second participant to sell additional imports from this higher-price sub-hub into the CAISO. As described in the testimony of Dr. Harvey, this basic scenario has apparently occurred in PJM on two different situations. First, on PJM's interface with the New York ISO, and again along PJM's southern and western interfaces with the Dominion (VACAR) and AEP Balancing Authority Areas. In addition, based on DMM's own experience with monitoring and investigating a variety of questionable trading practices involving imports and exports in the CAISO markets over the years, DMM is concerned that – absent additional information and data provided by the external BAA – we will have a limited ability to monitor and ensure that the resources (System Resources) purportedly supporting scheduled import and export transactions accurately represented the approximate location of the actual resources supporting these scheduled transactions.

Q. GIVEN THESE CONCERNS, DID YOU PROVIDE ANY RECOMMENDATIONS TO THE CAISO?

A. Yes. DMM identified these risks and concerns to the CAISO regarding the sub-hub proposal and recommended that if the CAISO adopted this approach, a number of protections should be included in the proposal.

Q. PLEASE DESCRIBE DMM'S RECOMMENDATIONS.

A. First, DMM recommended that the CAISO include scheduling and informational requirements that would be applied to all individual Scheduling Coordinators ("SCs") that applied for a Resource ID from the CAISO to schedule energy between the CAISO and any of the sub-hubs. For example, DMM suggested that each SC be required to explicitly agree that the Resource ID reflects the actual source of generation that would be used to support any schedules or bids submitted under the Resource ID. DMM also recommended that the CAISO explicitly establish that it would have the authority to review requests by SCs for Resource IDs associated with each of the established sub-hubs, and to be able to request additional information that the CAISO deemed necessary, such as whether the SC actually owned or controlled resources within the sub-hub for which the SC was requesting a Resource ID. DMM suggested that if an SC did not control any physical generation sources or could not demonstrate contractual control of any resources within the applicable sub-hub, the CAISO would have the explicit authority not to issue a Resource ID to the SC for that sub-hub. In addition, DMM identified other information that may be requested by the CAISO, such as (a) metered generation data for any generating resource under the SC's control within the applicable sub-hub(s), and (b) information on bilateral trades and schedules to and from other Market Participants within the SMUD and TID IBAAs.

Second, DMM noted that in order to further mitigate concerns about the sub-hub approach, it would be important for the CAISO to reach an agreement with the SMUD and TID BAAs under which these IBAAs would, upon request of the CAISO, provide information that the CAISO may need to assess and verify the source supporting schedules from the various sub-hubs. For example, in order to determine if the type of circular scheduling activity described earlier in my testimony was occurring or to be able to determine the actual source supporting a schedule or set of schedules, the CAISO may need to review schedules and e-tags submitted by Market Participants to the SMUD and TID Balancing Area Authorities for transactions between the various sub-hubs within the SMUD and TID IBAAs (e.g., between the Western and SMUD sub-systems within the SMUD IBAA).

Finally, DMM strongly recommended that the CAISO explicitly reserve the authority and establish the software capability necessary to quickly switch to a single hub approach if the CAISO believed that any of the concerns with the sub-hub proposal materialized. DMM viewed this recommendation as consistent with the general authority exercised by PJM when it combined multiple proxy buses into a single proxy bus on several occasions when problems with multiple proxy buses were identified. Dr. Harvey discusses PJM's actions in his testimony.

Q. COULD THE CONCERNS WITH A SUB-HUB APPROACH BE ADDRESSED BY SIMPLY ENFORCING MARKET RULES PROHIBITING SPECIFIC TYPES OF BEHAVIOR?

A. The CAISO and DMM have come to conclude that these concerns cannot be sufficiently mitigated – even with an intensive monitoring and investigative effort –because without more visibility of the SMUD and TID systems and bilateral transactions within these systems, it will not be possible for the CAISO and DMM to ensure that the data reported is in fact consistent with Market Participants' actual use of their resources. For example, behavior that was inconsistent with the intent of the scheduling rules that would apply under the sub-hub approach could be subject to provisions of the MRTU tariff prohibiting the submission of "false or misleading information" to the CAISO (Section 37.5 of the CAISO Tariff) and prohibiting market manipulation, which includes "any device, scheme or artifice to defraud" (Section 37.7). FERC market rules similarly prohibit the provision of false information to a system operator (18 CFR § 35.37(b) Communications) and market manipulation (18 C.F.R. § 1c.2 Prohibition of Electric Energy Market Manipulation). However, relying on these behavioral market rules if anomalous market behavior was detected would require an extensive monitoring and investigation effort by DMM. In addition, potential violations of these behavioral market rules would need to be referred by DMM to FERC's Office of Enforcement for more formal investigation and enforcement. Even with access to the type of informational provisions suggested by DMM, it is very difficult to meet the relatively high burden of proof that is likely necessary to support effective enforcement of these CAISO and FERC market rules.

Finally, as noted previously in my testimony, even if participants did not intentionally misrepresent the actual location of the resources supporting interties schedules or create circular import and export schedules, differences in LMPs for these different sub-hubs would create an definite incentive for bilateral trading between different participants that would have the same end result, i.e. forcing the CAISO to "buy high" and "sell low" relative to the value of imports and exports in terms of their impact on congestion within the CAISO system. Again, this would further limit the extent to which concerns about the sub-hub approach could be mitigated by CAISO and FERC market rules such as behavioral market rules prohibiting false information and market manipulation.

Q. DID THE CAISO MODIFY ITS PROPOSALS IN RESPONSE TO THESE CONCERNS?

A. Yes. The CAISO incorporated the general principle of DMM's recommendations concerning the use of special Resource IDs in its initial sub hub proposal, and expressed general support for adopting DMM's other specific recommendations in the event that the sub-hub approach was adopted. However, the CAISO did not develop details of how to implement these recommendations because – based on the concerns expressed by DMM and similar feedback from the CAISO's MSC, Dr. Harvey, and the CAISO's own internal expert review – the CAISO reconsidered the overall benefits of the sub-hub approach relative to a single hub approach. Ultimately, the CAISO's final single hub proposal still includes certain aspects of DMM's proposed informational requirements, in the form of a provision for developing alternative pricing arrangements with individual participants on a case-by-case basis, subject to specific pre-agreed requirements for information and verification. This provision of the CAISO's final proposal is discussed later in my testimony.

Q. HOW DOES THIS REVISED PROPOSAL ADDRESS THE PROBLEMS YOU IDENTIFIED?

A. The single hub approach proposed by the CAISO essentially eliminates the key problems associated with the pricing incentives that would exist under the sub-hub approach that were identified by DMM, the MSC and Dr. Harvey. Under the single hub approach, the default price paid for all imports scheduled from the SMUD and TID IBAA into the CAISO will be based on the LMP at the Captain Jack substation, while the default price for all exports from the CAISO will be based on the cost of a decrease in generation at the SMUD Aggregate System Resource, as represented by the LMP calculated for the SMUD hub. This default pricing rule eliminates the incentive for a participant to misrepresent or somehow disguise the source of any additional supply at a lower priced System Resource (such as Captain Jack or Western) as an import from a higher priced System Resource (such as SMUD). Since LMPs will tend to be lower at the Captain Jack System Resource than at the SMUD Aggregate System Resource during periods of north-to-south congestion, this default settlement rule will also eliminate the potential for circular import/export scheduling patterns that would force the CAISO to "buy high" and "sell low," without any congestion management benefits to the CAISO system.

Q. DOES THIS DEFAULT PRICING RULE DETER ADDITIONAL IMPORTS OF GENERATION FROM RESOURCES THAT COULD HELP BETTER MANAGE CONGESTION WITHIN THE CASIO?

A. No. The CAISO's final proposal includes provisions that allows any entity to obtain an alternative pricing arrangement by providing more detailed information to the CAISO that, among other things, will verify the location of the resources within the IBAA that will be incremented to support an import into the CAISO, or decremented as a result of an export. Thus, any entity that actually controls generation – physically or contractually – can seek to establish this type of agreement. To the extent this generation is helpful in relieving congestion on the CAISO grid under any particular system condition, the CAISO's market software will be able to utilize these resources to manage congestion, and the LMP paid under this agreement will reflect these additional congestion relief benefits.

Q. WHAT SPECIFIC ELEMENTS WOULD BE INCLUDED IN SUCH PRICING AGREEMENTS?

A. The specific details of pricing agreements will need to be developed on a case-by-case basis. However, the special agreements between PJM and several entities discussed in Dr. Harvey's testimony illustrate several key elements that should be included in such agreements to mitigate the concerns identified with the sub-hub approach. First, the data that must be made available under these agreements includes the entire portfolio of the subject entity and its affiliates, including load and generation data, and information regarding all bilateral transactions entered into by the entity. Second, the agreements must establish clear conditions that must be met for the entity to receive the special pricing, rather than the default price. For example, under the PJM agreements, if an entity makes spot market purchases while simultaneously selling to PJM, the entity is not eligible to receive a special price for any sales to PJM. Finally, the agreements should provide the CAISO with audit rights. Under the PJM agreements, PJM may perform audits to verify summary data provided by the entity to PJM, and allows PJM to cancel the agreement with limited advance notice.

Q. HOW WOULD SUCH PRICING AGREEMENTS DIFFER FROM THE TYPE OF INFORMAL OR SCHEDULING REQUIREMENTS THAT MIGHT HAVE BEEN REQUIRED UNDER THE INITIAL SUB-HUB PROPOSAL?

A. Under the CAISO's initial sub-hub proposal, extensive after-the-fact monitoring and investigation would first be required. If, based on this monitoring, DMM developed a reasonable belief that false or misleading information may have been used to circumvent market rules, the matter would then need to be referred to FERC's Office of Enforcement. While FERC may issue penalties of up to $1 million per day for violations of FERC and CAISO market rules, the actual consequence for potential non-compliance would be subject to substantial uncertainty. Under the CAISO's final proposal, however, the default pricing rule would be applied unless or until an agreement is reached, specifically establishing conditions and requirements that must be met for the entity to receive the special pricing. Thus, the CAISO's final approach would allow special pricing to be based on much clearer, pre-agreed criteria, and to place much of the burden of data preparation and verification on the participant, rather than on the limited resources of the CAISO's DMM, and, potentially, the Commission's own Office of Enforcement.

B. DMM REVIEW OF THE COUNTER PROPOSAL OFFERED BY THE IBAA ENTITIES

Q. DID YOU REVIEW THE COUNTER PROPOSAL SUBMITTED BY THE IBAA ENTITIES DURING THE IBAA STAKEHOLDER PROCESS?

A. Yes, I reviewed the proposal, and participated in discussions regarding the proposal with the IBAA entities in order to clarify my understanding of their proposal. The IBAA entities supporting this counter proposal included the SMUD-Western and TID Balancing Authorities, and the Transmission Agency of Northern California ("TANC") and its members.

Q. DID YOU HAVE ANY CONCERNS ABOUT THE COUNTER PROPOSAL OFFERD BY THE IBAA ENTITIES?

A. Yes. A major fundamental problem with the IBAA entities' proposal is that it calls for the CAISO to model and price all import or export schedules as physical injections at whatever ISP the Market Participant chooses to schedule the import or export. This approach would result in the same basic problem that would exist under a simple radial modeling approach, and that could occur under a sub-hub approach. Specifically, regardless of the actual source of their generation, Market Participants would schedule all imports into the CAISO at the ISPs that have the highest LMPs, while scheduling all exports from the CAISO at the ISPs that have the lowest LMPs. For example, when north-to-south congestion occurs Market Participants would have an incentive to schedule all imports at the Tracy 500 and SMUD ISPs, while scheduling all exports at the Cottonwood ISP between the CAISO and Western's system. In addition, this approach could provide strong incentive for Market Participants – individually or through bilateral trades – to schedule additional offsetting volumes of exports and imports that the CAISO would be required to "buy high" and "sell low".

Q. DID THE IBAA ENTITIES' COUNTER PROPOSAL HAVE ANY PROVISIONS TO ADDRESS THESE MARKET MONITORING ISSUES?

A. The IBAA entities' counter proposal calls for the CAISO and IBAA entities to form a joint review committee to "collaboratively develop and implement processes regarding the market behaviors that would be monitored," which could include "an ongoing interbalancing area operations committee with market surveillance oversight responsibilities." However, nothing in the IBAA entities' counter proposal would explicitly or implicitly prohibit the type of scheduling behavior described above. On the contrary, the counter proposal is specifically designed to ensure that Market Participants have the ability to schedule imports and exports at ISPs where prices would be most favorable to them, without any requirements or consideration as to the actual source of the generation supporting these schedules. Thus, the IBAA counter proposal is specifically designed to permit scheduling practices that conflict with the fundamental concerns identified by the CAISO. As previously described in my testimony, DMM believes it is critical that market rules governing scheduling behavior be clearly specified before the fact. Establishing such market rules before the fact is particularly important in this case, given the fundamental conflict that exists between the scheduling and pricing choices that the IBAA counter proposal is designed to establish, and the market design and monitoring concerns of the CAISO.

Q. DID THE IBAA COUNTER PROPOSAL HAVE ANY PROVISIONS FOR PROVIDING DATA TO THE CAISO THAT WOULD ADDRESS MARKET MONITORING ISSUES?

A. The IBAA entities' counter proposal called for the IBAA entities to "work collaboratively with the CAISO to develop a mutually agreeable and reciprocal process for developing, securing and sharing historic generation data." However, any data under such an agreement would be shared "on a reciprocal, after-the-fact basis," and data would not be allowed to be removed from each other's sites. Although no further details of this proposal have been worked out, the approach to data outlined in the IBAA entities' counter proposal is fundamentally insufficient with respect to the data requirements needed to address the market monitoring concerns of the CAISO. First, since the IBAA entities' counter proposal is not designed to prohibit or even deter the type of scheduling behavior that the CAISO is concerned about, it appears that any data exchanged under this approach could only be used to help improve modeling of the IBAA, rather than to actually mitigate any market monitoring concerns. Again, DMM believes that it is critical that Market Participants seeking special pricing must agree to provide supporting data to the CAISO in a manner that allows timely and objective verification by the CAISO of the resources supporting scheduled import and export transactions. As described previously in my testimony, data required for such verification goes beyond historical generation data, and includes bilateral trading data as well. In addition, on a practical level, given the significant volume of data needed to verify the source of generation supporting import and export transactions, it would simply be infeasible to perform the necessary data analysis and review at the site of the IBAA entities. Thus, there is a wide gap between the data exchange provisions outlined in the IBAA entities' proposal, and the data provisions that would be required to mitigate the CAISO's market monitoring concerns.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER08-___-000**

I, Eric W. Hildebrandt, declare under penalty of perjury, that the foregoing questions and answers labeled as the Testimony of Eric W. Hildebrandt were prepared by me, with the assistance of others working under my direction and supervision; and that the facts contained in those answers are true and correct to the best of my knowledge, information and belief.

Executed on: June 11, 2008
Date

Eric W. Hildebrandt

(California Notarial Acknowledgment Attached)

State of California)
)
County of Sacramento)

On June 11, 2008, before me, Martha M. Sedgley, Notary Public,

personally appeared Eric W. Hildebrandt,

MARTHA M. SEDGLEY
COMM. #1690762
Notary Public-California
PLACER COUNTY
My Comm. Exp. Sep. 27, 2010
BMP1

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Martha M. Sedgley
Notary Public

Attachment H

Exhibit No. ISO-3 - Testimony of Dr. Scott Harvey; and
Exhibit No. ISO-4 - Paper by Dr. Scott Harvey, "Proxy Buses and Congestion
Pricing of Inter-Balancing Authority Area Transactions" June 9, 2008

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER08-___-000**

PREPARED DIRECT TESTIMONY
OF
SCOTT M. HARVEY

June 17, 2008

Table of Contents

EXECUTIVE SUMMARY

The CAISO's proposal to use a single pricing point, the SMUD-TID IBAA, to model and price all interchange transactions scheduled on a contract path through the SMUD or TID Balancing Authority Areas, is reasonable and consistent with the methods used in Eastern LMP based markets to price scheduled interchange. Moreover, the CAISO proposal reflects experience in other LMP markets which has clearly shown that if there are material price differences across the various Intertie Scheduling Points at which imports can be scheduled for delivery to the CAISO Balancing Authority Area, sellers will use contract path schedules to deliver imports to the Intertie Scheduling Point with the highest price, regardless of the actual location of the generation that will be increased to support that import.

Such an ability of sellers to choose the location at which they sell power to the CAISO by constructing a fictitious contract path would benefit sellers by enabling them to realize higher payments for their energy, but these payments would be premised on a predicted favorable impact of these imports on internal CAISO transmission constraints that would not exist in real-time operation because the actual impact on CAISO transmission constraints would not be determined by the contract path. The CAISO pricing proposal addresses the potential for such inefficient scheduling practices at the SMUD and TID Intertie Scheduling Points by establishing a single SMUD-TID IBAA, while also providing for alternative pricing arrangements with entities desiring such a different arrangement that agree to provide the CAISO with information in addition to the interchange schedule that is sufficient to show that it is appropriate for the CAISO to apply an alternative pricing arrangement to particular interchange schedules with the SMUD or TID Balancing Authority Areas.

There is no valid reason to defer implementation of the CAISO pricing proposal for the SMUD-TID IBAA. There is no question that if presented with different prices at alternative scheduling points with a single Balancing Authority Area, market participants will schedule transactions along a contract path external to the Balancing Authority Area to the scheduling point with the most favorable price. These contract path schedules will not reflect real-time flows and using them to calculate settlement prices for scheduled interchange will result in congestion rent shortfalls in the CAISO settlement system that will result in higher costs to CAISO consumers and will also create unnecessary reliability issues for the CAISO. This kind of behavior has been repeatedly observed and continues to be observed in other markets. There is no need to wait to see what happens in California. Moreover, the CAISO proposal is consistent with existing practice in other markets. All of the existing LMP-based pricing systems currently utilize proxy bus mechanisms for analyzing and pricing the congestion impacts of interchange schedules that are analogous to the methods the CAISO proposes to use to model and price scheduled interchange with the SMUD-TID IBAA.

I. INTRODUCTION AND OVERVIEW

A. Experience

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Scott M. Harvey; my business address is Suite 300, 350 Massachusetts Avenue, Cambridge, MA 02139.

Q. DR. HARVEY, WHAT IS YOUR OCCUPATION?

A. I am a director with LECG, LLC an economic and management consulting company.

Q. DR. HARVEY, PLEASE DESCRIBE YOUR QUALIFICATIONS

A. During the period from 1994 to 1999, I was actively involved as a consultant to the New York Power Pool and the PJM Supporting Companies in the restructuring of the New York and PJM power pools and assisted with the development and implementation in those control areas of open access markets based on LMP pricing, financial transmission rights, and day-ahead financial markets with security-constrained unit commitment. Prior to the startup of the NYISO, I was extensively involved in testing elements of the NYISO day-ahead market and real-time pricing software. I have continued to be a consultant to the NYISO since its startup, providing consulting assistance on issues relating to the coordination and pricing of scheduled net interchange with adjacent control areas; demand response; TCC auctions and credit requirements; transmission outage performance incentives; locational reserve pricing; installed capacity markets; market power mitigation; transmission expansion and virtual (convergence) bidding.

During the period from 1998 to 2000, I was actively involved, as a consultant to a group of New England market participants (initially Westbrook Power), and later ISO-New England ("ISO-NE") in the reform of the New England power markets and the development of a two-settlement market design based on LMP pricing, financial transmission rights and a day-ahead financial market with security-constrained unit commitment. More recently, during the period February 2003 to May 2004, I was jointly retained by ISO-NE and NYISO to assist them with the development on improved process for coordinating scheduled net interchange ("VRD"), during the period 2001 to 2004 I was a consultant to the Mid West ISO, supporting the development of the Midwest ISO's Stage 2 congestion management system based on LMP pricing, financial transmission rights and a day-ahead financial market with security-constrained unit commitment.

I was jointly retained by the Ontario IMO and the NYISO to assist them with analysis of interchange scheduling practices during 2004. During 2007 and 2008, I have been a consultant to the Ontario IESO on the potential implementation of a day-ahead market in Ontario, including issues relating to interchange pricing.

Since 1997, I have been involved in a variety of efforts to diagnose and address the causes of the problems that have affected the power markets coordinated by the California ISO. Since August 2004, I have been a consultant to the California ISO, assisting with the implementation of the MRTU market design.

I have a B.A. in economics from the University of Illinois and a Ph.D. in economics from the University of California Berkeley. Prior to my employment as a consultant at LECG and Putnam, Hayes and Bartlett, I spent ten years in antitrust enforcement at the Federal Trade Commission, where I specialized in the antitrust and regulatory issues in the oil and gas industries. My CV is attached as Appendix 1.

B. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain why it is necessary that the California Independent System Operator Corporation ("CAISO") model and price interchange transactions (*i.e.*, import and export transactions between the CAISO and certain external Balancing Authority Areas) in the manner proposed in this filing under the Market Redesign and Technology Upgrade ("MRTU") market design. Specifically, I will explain: (a) the adverse outcomes that may result absent appropriate modeling and pricing for interchange transactions and why the appropriate modeling and pricing of interchange transactions are extremely important with a market design that uses location-based marginal prices ("LMPs"), (b) why the CAISO's proposal for the pricing of scheduled net interchange with the Sacramento Municipal Utility District ("SMUD") and Turlock Irrigation District ("TID") Balancing Authority Areas is both reasonable and necessary for the reliable and efficient management of transmission congestion on the CAISO system under the MRTU market design particularly in light of past experience with proxy bus pricing in the eastern interconnection and given the CAISO's assessment of the varying congestion impacts of changes in generation output at various locations that could support a change in scheduled interchange with the SMUD or TID Balancing Authority Areas, and (c) how the modeling and pricing of interchange transactions has been handled in other Regional Transmission Organizations ("RTOs") that employ LMP and interconnect with both market and non-market areas, and why the CAISO proposal is consistent with the way the eastern LMP markets have been pricing scheduled interchange for a number of years.

Q. WHY IS IT IMPORTANT THAT THE CAISO MODEL AND PRICE INTERCHANGE TRANSACTIONS WITH THE SMUD-TID IBAA PURSUANT TO CAISO'S PROPOSAL?

A. The CAISO is proposing to model the SMUD Balancing Authority Area and the TID Balancing Authority Area as a single "Integrated" Balancing Authority Area (hereinafter "SMUD-TID IBAA") for the purpose of analyzing congestion impacts on the CAISO transmission system and pricing net interchange. In general, the purpose of modeling and pricing interchange transactions with the SMUD-TID IBAA on an integrated basis is to: (a) more accurately model the effect of those transactions on transmission constraints on the CAISO Controlled Grid and thereby improve the accuracy of congestion management on the CAISO Controlled Grid, and (b) reduce the inefficient scheduling incentives that can exist if multiple pricing points are used to settle interchange transactions with a single Balancing Authority Area (*e.g.*, the incentive to schedule an import as if it were sourced from generation located at the pricing point with the highest price even though the energy would actually be sourced from generation located elsewhere, and would result in flows over binding transmission constraints that would be quite different than the flows associated with the generation scheduled at the pricing point).

Q. WHY IS IT CRITICAL TO ADDRESS THESE INEFFICIENT SCHEDULING INCENTIVES?

A. These concerns regarding inefficient scheduling incentives are not hypothetical. As discussed briefly below and at greater length in the accompanying paper,[1] these problems have repeatedly manifested themselves in the eastern interconnection across scheduling points spanning much larger geographic and electrical distances than those at issue with the pricing of interchange between the CAISO and the SMUD and TID Balancing Authority Areas. There is no question that if presented with different prices at alternative scheduling points with a single Balancing Authority Area, market participants will schedule transactions along a contract path external to the Balancing Authority Area to the scheduling point with the most favorable price. This kind of behavior has been repeatedly observed and continues to be observed in other markets. There is no need to wait to see what happens in California.

Mr. Rothleder and Dr. Price explain in their testimony why the CAISO has concluded that the SMUD and TID Balancing Authority Areas are uniquely situated with respect to their interconnection with the CAISO system and with respect to likely binding

---

[1] Dr. Scott Harvey, "Proxy Buses and Congestion Pricing of Inter-Balancing Authority Area Transactions" June 9, 2008.

transmission constraints on the CAISO transmission system, and why it is necessary that they be modeled and priced as proposed by the CAISO for the initial start of MRTU.

C. The CAISO's SMUD-TID IBAA Proposal

Q. PLEASE DESCRIBE THE CAISO'S SMUD-TID IBAA INTERCHANGE PRICING PROPOSAL CONTAINED IN THE INSTANT FILING.

A. A full explanation of the details of the CAISO's final SMUD-TID IBAA interchange pricing proposal is contained in the testimony of Mr. Rothleder and Dr. Price. In summary, the CAISO's final proposal establishes a single default pricing point for all interchange transactions between the CAISO and either the SMUD Balancing Authority Area or the TID Balancing Authority Area. There is one default modeling and pricing point for imports and another default modeling and pricing point for exports.

Under the default pricing rules, all transactions between the CAISO and the SMUD-TID IBAA would be modeled and priced as follows. For all imports from the SMUD-TID IBAA to the CAISO (*i.e.*, an import scheduled at one of the CAISO's Intertie Scheduling Points with either the SMUD or TID Balancing Authority Areas), the impact of such imports on the CAISO Controlled Grid would be determined by modeling the transaction as if the marginal resources within the SMUD-TID IBAA whose output was increased to support the import transaction were located at the Captain Jack substation. The CAISO will implement this by creating a System Resource / proxy bus in the Full Network Model located at the Captain Jack substation. When a market participant schedules an import from the SMUD-TID IBAA to the CAISO at one of the various Intertie Scheduling Points between the CAISO Controlled Grid and the SMUD-TID IBAA, the CAISO will map the schedule for pricing purposes (i.e., model the scheduled injection at) to the System Resource located at the Captain Jack substation in the CAISO's Full Network model.

The default LMP used to price imports scheduled at the Intertie Scheduling Points between the CAISO Controlled Grid and either the SMUD or TID Balancing Authority Areas will be the LMP calculated at the System Resource / proxy bus located at the Captain Jack substation. As discussed in more detail in Mr. Rothleder and Dr. Price's testimony, the application of the CAISO's SMUD-TID IBAA proposal to the pricing of import transactions will not alter the CAISO's compliance with practices required by the Western Electricity Coordinating Council ("WECC") contract path interchange scheduling and check-out procedures and the scheduling limits for all applicable Intertie Scheduling Points.

A similar default pricing process will be applied to all exports from the CAISO to the SMUD-TID IBAA except that the location of the System Resource / proxy bus in the CAISO's Full Network Model will not be at the Captain Jack substation; rather, the System Resource / proxy bus will be at a set of buses defined as the SMUD Hub.[2] When

[2] The SMUD Hub is comprised of the following transmission buses (using CAISO naming conventions) and will have the following Intertie Distribution Factors: (1) 37005_ELVERTAS 230kV with an Intertie Distribution Factors of 0.14; (2) 37010_HURLEY S 230kV with an Intertie Distribution Factors of 0.31; (3) 37012_LAKE 230kV with an Intertie Distribution Factors of 0.19; and (4) 37016_RNCHSECO 230kV with an Intertie Distribution Factors of 0.36. *See* the January 22, 20008 CAISO Power Point Presentation Update "Modeling

a market participant schedules an export from the CAISO to the SMUD-TID IBAA at one of the various Intertie Scheduling Points between the CAISO Controlled Grid and the SMUD or TID Balancing Authority Areas, the CAISO will map the schedule (or model the scheduled injection at) to the System Resource in the CAISO's Full Network Model which is located at the SMUD Hub. The default LMP will be the LMP calculated at the System Resource / proxy bus located at the SMUD Hub. The default LMP calculated will be applied to exports from the CAISO Balancing Authority Area sinking in either the SMUD or TID Balancing Authority Areas. As in the case of imports, Mr. Rothleder and Dr. Price explain that the application of the CAISO's SMUD-TID IBAA proposal to the pricing of export transactions will not alter the established WECC practices for interchange scheduling and check-out procedures nor will it alter the scheduling limits for the applicable Intertie Scheduling Points.

It is important to recognize that the above-described default pricing rules are designed to apply to the schedules submitted by Scheduling Coordinators representing all CAISO market participants, not just those Scheduling Coordinators representing SMUD, TID, or to those of entities that serve load or operate generation within the SMUD and TID Balancing Authority Areas. Any alternative to the CAISO proposal must be evaluated with respect to how it would apply to the transactions of all entities able to

---

and Pricing of Integrated Balancing Authority Areas" at slide 38. The Power Point Presentation can be found at (http://www.caiso.com/1f56/1f56eb9739860.pdf).

schedule such interchange transactions and not simply how it would apply to the transactions of a particular entity scheduling interchange between the CAISO Balancing Authority Area and either the SMUD or TID Balancing Authority Area.

Q. WHY DO YOU REFER TO THE CAISO PRICING RULES AS THE "DEFAULT" PROPOSAL?

A. The reason why the CAISO interchange modeling and pricing proposal is called a "default" proposal is that the proposal allows for alternative pricing arrangements if, as described further by Dr. Hildebrandt, an entity desiring such a different arrangement agrees to provide the CAISO with information in addition to the interchange schedule that is sufficient to show that it is appropriate for the CAISO to apply an alternative pricing arrangement to particular interchange schedules with the SMUD or TID Balancing Authority Areas.[3] Absent the entity and the CAISO entering into a specific alternative modeling and pricing arrangement for interchange transactions between the CAISO and the SMUD-TID IBAA, the default pricing proposal will apply to all scheduled interchange transactions with the SMUD or TID Balancing Authority Areas.

---

3 As discussed briefly in Section IV below and at more length in the paper, "Proxy Buses and Congestion Pricing of Inter-Balancing Authority Area Transactions," PJM began implementing such an approach utilizing alternative pricing arrangements with several Balancing Authority Areas in early 2007.

II. THE IMPORTANCE OF MODELING AND PRICING OF INTERCHANGE TRANSACTIONS WITHIN AN LMP-BASED MARKET DESIGN.

Q. WHY DOES THE CAISO NEED TO MODEL INTERCHANGE TRANSACTIONS WITH THE SMUD AND TID BALANCING AUTHORITY AREAS?

A. Changes in the level of scheduled interchange with the SMUD and TID Balancing Authority Areas (as well as other Balancing Authority Areas) can affect the flows on binding transmission constraints on the CAISO Controlled Grid. A fundamental feature of LMP pricing systems is that when transmission constraints are binding, location matters. Depending on the location of binding constraints on the system, certain resources (*e.g.*, generation and dispatchable load) will have more impact than others in relieving those constraints and therefore warrant incurring a higher cost in order to increase or decrease net injections at those locations. This is true for generation and loads internal to the CAISO Controlled Grid and is equally true for the location of the resources dispatched to implement interchange transactions (imports and exports) that are located within the footprint of the SMUD or TID Balancing Authority Areas. Therefore, in order to manage transmission congestion on the CAISO Controlled Grid on a reliable least cost basis, it is important to accurately portray the location of the resources within the SMUD or TID Balancing Authority Areas whose output would be increased or decreased to support changes in scheduled interchange in the CAISO's Full Network Model.

Under MRTU, interchange transactions will be paid a price that reflects the impact of the transaction on transmission constraints internal to the CAISO Balancing Authority Area. In order to calculate that impact, and thus to determine the price paid for the interchange transactions or the congestion charges on the interchange transactions, it is necessary to specify the location at which generation external to the CAISO Balancing Authority Area will be increased or decreased to support the change in scheduled interchange.

Specifying the location at which generation will be increased or decreased to support a change in scheduled net interchange is not straightforward because the CAISO neither controls the dispatch, nor knows the location of the generation located within the SMUD-TID IBAA that will be dispatched up or down to support changes in scheduled interchange with the CAISO. The CAISO, like PJM and the NYISO, must make a modeling decision to calculate the congestion impact of interchange schedules based on some location. While no single modeling treatment will be perfect under all system conditions likely to exist in the CAISO and the rest of the WECC, the better the modeling approximation that is utilized by the CAISO, the more reliable will be CAISO operation and the lower the cost to CAISO consumers.

Q. IN PROVIDING AN OVERVIEW OF THE CAISO'S PROPOSAL YOU USED THE TERM "PROXY BUS." WHAT IS A PROXY BUS?

A. Proxy bus is one of the terms eastern RTOs have used to refer to the pricing points for interchange transactions. They can also be referred to as external nodes, interface prices or pricing points.

Proxy buses are locations external to the CAISO Controlled Grid that are selected to represent the most likely impact on transmission system flows on the CAISO Controlled Grid of the combined effect of all changes in generation that would occur within an external Balancing Authority Area to support changes in the level of scheduled net interchange. In the case of most Balancing Authority Areas, an increase or a decrease in generation at a location on their transmission system will impact the flows on multiple CAISO tie lines.

Q. HOW WILL THE CAISO MODEL INTERCHANGE TRANSACTIONS WITH THE SMUD-TID IBAA?

A. As noted earlier, and as further described in the testimony of Mr. Rothleder and Dr. Price, the CAISO's Full Network Model will extend beyond the CAISO Controlled Grid and will represent, in a somewhat simplified or equivalenced manner, the transmission network of the SMUD and TID Balancing Authority Areas. The CAISO will create System Resources in its Full Network Model that represent the location of the resources within the SMUD or TID Balancing Authority Areas that likely will be used to implement an interchange transaction between the SMUD-TID IBAA and the CAISO Balancing Authority Area. All of the existing Intertie Scheduling Points on the CAISO Controlled Grid can still be used by market participants to schedule the contract path of interchange transactions and the CAISO will link or associate schedules at the various Intertie Scheduling Points with the SMUD-TID IBAA and the System Resources within the Full Network Model for CAISO modeling and pricing purposes. When, for example, a market participant schedules an import from the SMUD Balancing Authority Area to the CAISO, the CAISO will calculate the congestion and flow impacts on the CAISO Controlled Grid by modeling the schedule as an injection at the associated System Resource.

Q. WHY IS THE PRICING SYSTEM PROPOSED BY THE CAISO NECESSARY?

A. As described above, imports scheduled to be delivered over a common scheduling point but supported by generation at different locations on the transmission system external to the CAISO can have different impacts on internal CAISO constraints. If the differences in congestion impacts are expected to be material, then it is necessary to account for these differences in scheduling imports both day-ahead (in the CAISO's Integrated Forward Market) and in the CAISO's hour-ahead scheduling process ("RTUC" or "HASP"). There are three reasons for this. First, from a reliability perspective, more accurate predictions of the impact of imports on internal CAISO transmission constraints will reduce the potential for situations to arise in real-time in which transmission system flows are so different from those that were modeled in the day-ahead or hour-ahead commitment process that it is not possible for the CAISO to solve the constraints with the units that are on-line, or the constraints can only be solved in real-time by curtailing scheduled interchange transactions.

Second, from a market perspective, more accurate predictions of the impact of imports on internal CAISO transmission constraints will enable the CAISO to more fully schedule use of the CAISO transmission system in the forward unit commitment processes (IFM and RTUC), thereby potentially reducing the cost of meeting CAISO load.

Third, under an LMP pricing system such as MRTU, the price paid for power varies locationally based on the differential impact injections or withdrawals at each location would have on binding transmission constraints on the CAISO transmission system. This is the case both for internal generation, external generation (imports), and external load (exports).[4] In determining the price paid for imports and the price charged for exports, it is therefore necessary for the CAISO to model imports as being sourced at some location, so their impact on internal CAISO transmission constraints can be calculated, and to similarly model exports as sinking at some location, so their impact on internal CAISO transmission constraints can be calculated. Some location must therefore be specified for the analysis of congestion impacts, but if the location at which imports are modeled as being sourced for the purpose of calculating congestion charges differs from the actual location at which generation would actually be increased to support the net imports, then the CAISO may be paying too much or too little for those imports.

This issue will not arise under MRTU for generation internal to the CAISO because the location of internal generation is known, and resources are paid the LMP price at their location for the power they generate (as validated by the generators meter

[4] The LMP price at each location is the sum over all binding transmission constraints of the shift factor of generation at that location on each binding transmission constraint times shadow price of that transmission constraint. If the shift factor of generation on binding constraints varies across locations, the LMP price will also differ.

data). In the case of scheduled interchange with another Balancing Authority Area, however, the CAISO generally does not determine or even know the location at which external generation will be increased to support imports by the CAISO or decreased to accommodate increased exports from the CAISO Balancing Authority Area. The location at which generation would be increased or decreased in the other Balancing Authority Area would be determined by the other Balancing Area Authority.

Because the price paid by the CAISO for imports sold into the CAISO coordinated spot markets will be determined in part by the modeled impact of the imports on internal CAISO transmission constraints, if the actual impact of those imports on the CAISO transmission system is different than the impacts that were modeled in the day-ahead market or the HASP, then the price paid for those imports may be greater than their actual value to CAISO consumers, or it might be lower than their value to CAISO consumers (causing too few imports to be scheduled). If the differences between the actual flows and those modeled day-ahead are sufficiently large that the actual transmission system flows associated with scheduled net interchange are not feasible in combination with other day-ahead schedules, then the CAISO congestion settlements will be revenue inadequate. If the impacted transmission constraints were not fully scheduled day-ahead, then the impact may show up as a reduction in the congestion rent surplus rather than a shortfall but in either case, it results in increased costs to CAISO transmission customers. For these reasons, it is important that the CAISO be able to use the information available to it to model, as accurately as is practical, the impact of changes in interchange schedules on its internal transmission constraints.

Q. WHAT PROBLEMS OR NEGATIVE EFFECTS WOULD THE CAISO AND STAKEHOLDERS ENCOUNTER IF THE CAISO DID NOT IMPLEMENT ITS SMUD-TID IBAA INTERCHANGE PRICING PROPOSAL?

A. If the CAISO were not able to model the effects on the CAISO Controlled Grid of interchange transactions with SMUD and TID Balancing Authority Areas using the proposed approach and instead were required to model the schedules for imports or exports as sourcing or sinking at the various Intertie Scheduling Points based on contract path schedules, *i.e.*, assuming the resources used to support interchange transactions with the SMUD and TID Balancing Authority Areas were located directly at or near each Intertie Scheduling Points with the CAISO Controlled Grid, this would lead to a number of adverse reliability and market impacts.

First, experience in other markets has clearly shown that if there are material price differences across the various Intertie Scheduling Points at which imports can be delivered to the CAISO Balancing Authority Area, sellers will use contract path schedules to deliver imports to the Intertie Scheduling Point with the highest price, regardless of the actual location of the generation that will be increased to support that import. The ability to choose the price at which they sell power to the CAISO benefits sellers by enabling them to realize higher payments for their energy, or to pay lower congestion charges on power delivered to CAISO loads, but the higher payments will be premised on a modeled favorable impact of these imports on internal CAISO transmission constraints that will not exist in real-time operation. The effect I just described has been referred to as "phantom congestion" by the Commission (i.e., congestion modeled in the Day-Ahead Market that is not present in real-time). As a result, the CAISO will pay the artificially high price to the external sellers, and then will have to dispatch high cost internal generation to solve the transmission constraint in real-time, giving rise to congestion rent shortfalls and raising consumer costs without receiving any corresponding benefit.[5]

Second, such a modeling approach would lead to adverse reliability impacts for CAISO consumers and the WECC because the CAISO would be required to anticipate congestion impacts in its day-ahead market model and hour-ahead (HASP) analysis, that would be inconsistent with the transmission system flows and congestion impacts that would be present in real-time. The effect I am describing is the reverse or the corollary to "phantom congestion." In other words, in this circumstance the modeling approach would not identify or would mask congestion in the Day-Ahead Market that will be present in real-time.

In addition, the incorrect modeling of the impact of scheduled interchange would cause the CAISO forward models to include counterflows on binding constraints that would not be present in real-time operations. The CAISO could not reliably operate in

[5] It should be kept in mind that each Balancing Area Authority maintains its aggregate scheduled net interchange with the rest of the interconnection during real-time operations, but does not dispatch to make the observed flows on any line match its contract path schedule. There is therefore in general no relationship between contract path schedules at the Intertie Scheduling Points and the real-time powerflows observed at those locations.

such a manner and would be forced to make the kind of ad hoc adjustments it does today in order to anticipate real-time conditions, denying CAISO consumers one of the benefits of MRTU implementation.

Third, there would be adverse market impacts because the ad hoc adjustments the CAISO would need to make in order to maintain reliability would lead to underutilization of the CAISO grid.

Q. DOES THE EXTERNAL LOCATION OF THE PRICING POINTS WITHIN THE SMUD-TID IBAA FOOTPRINT MEAN THAT THE CAISO WILL BE PROVIDING OR PRICING TRANSMISSION SERVICE OVER, OR MANAGING CONGESTON ON, THE SMUD OR TID TRANSMISSION SYSTEMS?

A. No. The sole purpose of creating and using the proposed System Resources is to calculate the effects of interchange transactions on, and to manage congestion on, the CAISO Controlled Grid. The System Resources used by the CAISO have nothing to do with either the provision or pricing of transmission service over the SMUD or TID transmission facilities or managing congestion on the SMUD or TID transmission systems. The owners and operators of the SMUD and TID transmission systems are the sole providers of transmission service over those facilities.

It is important not to confuse the interchange pricing issues which concern us in this filing with the enforcement of WECC contract path scheduling limits. The CAISO proposal for pricing scheduled interchanged with the SMUD and TID Balancing Authority Areas will not change the CAISO's adherence to WECC contract path scheduling procedures or limits. The CAISO will continue to enforce these limits and will continue to conduct transaction checkout with adjacent Balancing Authority Areas on a contract path basis. This is consistent with practice in the east where PJM continues to conduct transaction checkout with individual Balancing Authority Areas based on contract path schedules while applying the same proxy bus price to determine congestion charges and prices for imports from a number of distinct Balancing Authority Areas.

Nor will the CAISO's proxy bus pricing mechanism change the manner in which other Balancing Area Authorities or transmission providers within those areas manage congestion internal to their Balancing Authority Areas.

With MRTU's use of LMP pricing, the calculated congestion impacts are used to determine LMPs and congestion charges on the CAISO Controlled Grid, including the LMPs and congestion charges calculated and applied to import and export transactions. It is important to clearly understand that while the location of the proxy bus (or buses) in the CAISO's Full Network Model is within the SMUD-TID IBAA and external to the CAISO Controlled Grid (indeed its very purpose is to more closely approximate the location of the resources within the SMUD-TID IBAA whose output is adjusted to support interchange transactions with the CAISO), the LMPs calculated using the proxy bus are applied only to transactions sourcing or sinking on the CAISO Controlled Grid. In other words, the proxy bus mechanism establishes prices to be used in connection with use of the CAISO Controlled Grid, the proxy bus prices are not applied to transmission service over any non-CAISO Controlled Grid facilities.

Q. CAN'T THERE BE CIRCUMSTANCES IN WHICH THE GENERATION SUPPORTING A PARTICULAR INTERCHANGE TRANSACTION IS LOCATED SUCH THAT IT HAS A MORE FAVORABLE IMPACT ON INTERNAL CAISO TRANSMISSION CONSTRAINTS THAN WOULD BE THE

CASE FOR INTERCHANGE SUPPORTED BY GENERATION AT THE DEFAULT PROXY BUS?

A. Yes. In the stakeholder process, the SMUD-TID IBAA parties pointed to circumstances in which it would be appropriate for the CAISO to model and price imports from the SMUD-TID IBAA as supported by generation internal to the SMUD-TID IBAA, such as in a situation in which contract path scheduling limits are binding at both Captain Jack and Malin. It is essential to recognize in evaluating this claim that the CAISO's proposal envisions the CAISO paying an appropriately higher price for imports scheduled from the SMUD-TID IBAA in such a circumstance. The CAISO proposal simply seeks to condition the payment of such higher price on the provision by the relevant SMUD-TID IBAA entity of information enabling the CAISO to verify that the stated circumstances do in fact exist and thus that the higher price is appropriate. Absent this information, as discussed in the testimony of Dr. Hildebrandt, Mr. Rothleder and Dr. Price, the CAISO proposal to model imports from the SMUD and TID BAAs as an injection at the Captain Jack substation is appropriate and a reasonable representation of the location of the marginal resources supporting such an import transaction.

The position of the SMUD-TID IBAA parties, on the other hand, is apparently that the CAISO should be required to pay a price calculated based on the most favorable assumptions to them regarding the location of the generation supporting imports from their Balancing Authority Area in all circumstances,[6] regardless of whether or not the imports are actually supported by generation whose location warrants the higher price. It should be kept in mind that there is no symmetric obligation on the SMUD-TID IBAA entities to buy power offered by CAISO sellers based on a transparent pricing model. Instead, the SMUD-TID IBAA entities are free to buy power from CAISO sellers or refuse to buy power from CAISO sellers based on these parties subjective evaluation of the congestion and other impacts of such imports on their systems.

Moreover, the CAISO has no say over the criteria the SMUD-TID IBAA parties use to decide whether to buy power from CAISO sellers or the price they will offer to CAISO sellers in bilateral transactions. There is no obligation for the SMUD-TID IBAA parties to reach agreement with the CAISO on the criteria they use in their purchasing decisions from CAISO sellers, but this is the obligation that the SMUD-TID IBAA parties seek to put on the CAISO, that the CAISO must get the SMUD-TID IBAA's parties agreement to the criteria the CAISO will use to evaluate the economic and reliability impacts of imports from the SMUD-TID IBAA parties and exports to the SMUD-TID IBAA parties on the transmission system operated by the CAISO.

Q. AS OPPOSED TO PRICING INTERCHANGE AT THE DEFAULT PRICING POINT, COULDN'T THE CAISO AND THE SMUD-TID IBAA PARTIES EXCHANGE ADDITIONAL INFORMATION REGARDING THE RESOURCE

---

6 If the CAISO were required to implement an interchange pricing system with multiple prices for the SMUD-TID IBAA, sellers would construct their contract path schedules to deliver power to the proxy bus with the highest price, which would be highest because it was calculated based on the most favorable assumptions regarding the transaction's impact on internal CAISO transmission constraints.

WHOSE OUTPUT WOULD BE INCREASED OR DECREASED TO SUPPORT AN INTERCHANGE TRANSACTION ALLOWING THE CAISO TO USE A PRICE APPROPRIATE TO THAT LOCATION TO PRICE THE TRANSACTION?

A. Yes. If the CAISO knew which resources internal to the SMUD-TID IBAA would be dispatched at the margin to support interchange transactions, this information could be incorporated into the CAISO's pricing model. In other words, if the necessary information was exchanged with the CAISO, the CAISO would be able to identify the actual location and physical operating characteristics of the generation within the SMUD-TID IBAA that would be dispatched to support an interchange transaction and could calculate an appropriate price for the incremental output of that resource.

As noted by Mr. Rothleder, the CAISO's ultimate goal is to model in detail each neighboring Balancing Authority Area and to exchange detailed scheduling, generation and load information with such external Balancing Authority Areas so that the CAISO can accurately assess the impact of not only scheduled interchange transactions between the CAISO and each Balancing Authority Area, but also the impact of base flows on those systems on the CAISO Controlled Grid. This is a long-run goal that will need to be achieved in a number of steps over a period of years and can only be achieved with the cooperation of adjacent Balancing Authority Areas that have a similar interest in improving reliability and reducing costs. While the CAISO pricing proposal for the SMUD-TID IBAA does not reflect the intended end state, it is an improvement over the current scheduling and pricing mechanism, is better than the alternative proposed by the IBAA parties, and is a step forward toward the intended end state that ought to be taken.

Until the end state system is implemented, the CAISO must operate the transmission system based on the best information available to it, and the current CAISO proposal will enable it to do so. In the absence of better information, the CAISO will make reasonable assumptions or approximations regarding the location of the resources supporting interchange transactions between the SMUD and TID Balancing Authority Areas and the CAISO.

Q. DO THE EASTERN RTOS WITH LMP-BASED SYSTEMS ALSO USE LOCATIONS EXTERNAL TO THEIR FOOTPRINTS TO CALCULATE THE IMPACTS OF INTERCHANGE TRANSACTION ON THE TRANSMISSION SYSTEMS THEY OPERATE?

A. Yes. As I will discuss further in Section III below, the NYISO uses a single location within the PJM footprint to calculate the effects of interchange transactions between the NYISO and PJM on the transmission system operated by the NYISO. Similarly, PJM uses locations external to PJM, such as the SOUTH IMP and SOUTH EXP pricing points, to calculate the effects on the transmission system operated by PJM of interchange transactions between PJM and a number of adjacent Balancing Authority Areas.

Q. IS THIS NEED TO ASSESS THE IMPACT OF INTERCHANGE TRANSACTIONS ON THE TRANSMISSION SYSTEM UNIQUE TO BALANCING AUTHORITY AREAS THAT UTILIZE LMP FOR PRICING INTERCHANGE TRANSACTIONS?

A. No. It is important to recognize that the traditional vertically integrated utility Balancing Area Authority also makes modeling decisions regarding the estimated impact of additional imports or exports on transmission constraints internal to its Balancing Authority Area, but these decisions are not transparent. Unlike the CAISO, these entities do not have to stand willing to buy and sell power at a formula rate. If they do not like the impact of a particular import transaction on internal constraints, based on their subjective evaluation of the likely source of that transaction, they can simply decline to purchase power from the entity offering those imports.

It is also helpful in understanding the changes envisioned in the pricing of scheduled net interchange under MRTU that today, under the CAISO's zonal congestion model, imports having a favorable impact on internal CAISO transmission constraints (i.e., imports whose scheduling would reduce the need for out-of-merit dispatch of internal generation to manage intrazonal congestion) are not paid a premium for their favorable impact on these intrazonal constraints, they are simply paid the zonal price. Rather than having a "property right infringed," under the CAISO pricing proposal the SMUD-TID IBAA entities will have the opportunity to be treated more favorably than they are today, as long as they provide information required by the CAISO to show that their exports to the CAISO are supported by generation that has a favorable impact on internal CAISO transmission constraints. What the SMUD-TID IBAA parties do not get under the CAISO proposal is the opportunity to be paid a premium for power that in fact does not have a favorable impact on internal CAISO transmission constraints. SMUD-TID IBAA parties do not have a property right entitling them to extract artificially high prices from CAISO rate payers in this manner and do not have the ability to do so in today's market structure. The mere implementation of MRTU should not give them this ability. If their transactions do not have an appropriately favorable impact on internal

CAISO transmission constraints, they should not be receiving a premium for their transactions that is premised on such a favorable impact.

Moreover, the pricing treatment the SMUD-TID IBAA parties seek – to be able to schedule their interchange with the CAISO so that all of their imports would be paid the price appropriate only for actual generation having the most favorable impact on internal CAISO transmission constraints – would not be available to the SMUD-TID IBAA parties if they had they remained in the CAISO Balancing Authority Area; their generation would be paid the LMP price at its location, not the highest price at any location within the SMUD-TID IBAA. There is no basis for according such special treatment to SMUD and TID – at the expense of CAISO ratepayers – as a result of their decision to leave the CAISO Balancing Area Authority.

Q. IF RADIAL MODELING AND PRICING AT THE INTERTIE SCHEDULING POINTS IS NOT APPROPRIATE FOR INTERCHANGE TRANSACTIONS WITH THE IBAA, WHY IS THE CAISO PROPOSING TO USE SUCH A PRICING SYSTEM FOR MOST OF ITS OTHER INTERCONNECTIONS WITH ADJACENT BALANCING AUTHORITY AREAS?

A. Radial modeling of interchange schedules over each free flowing tie with adjacent Balancing Authority Areas can inaccurately represent the impact of these interchange schedules on internal transmission constraints if the Balancing Authority Areas are in fact not radially interconnected. This potential exists because, if the Balancing Authority Areas are not radially interconnected, the interchange schedules will flow over all parallel paths from source to sink rather than flowing over a single radial tie as was assumed in using a radial model.

Moreover, such radial modeling of interchange flows can inaccurately represent the impact of interchange schedules on internal transmission constraints if congestion charges and settlement prices are determined based on these radially modeled interchange schedules. This is because such a pricing system will provide a systematic incentive for market participants to schedule transactions as if they were flowing along the radial paths having the highest prices even if such transactions are not flowing on such paths. Unfortunately, only the interconnected Balancing Authority has this information; the CAISO does not.

Nevertheless, a radial model could be adequate from both a reliability and market perspective in some circumstances. For example, if the interchange schedules would have similar impacts on the relevant binding transmission constraints regardless of which tie line they are modeled as flowing over, then the radial modeling of interchange scheduled to flow over these ties would not matter much, and improving the Full Network Model to provide a better representation of these impacts need not be a high priority. Similarly, if the affected transmission constraints have low shadow prices, then the imperfect modeling of interchange schedule impacts would have limited practical importance. The importance of developing an improved model of the congestion impacts of scheduled interchange is therefore not equal at all locations, and the importance of developing improved modeling may change over time as the entry or exit of generation or the growth of demand cause new transmission constraints to bind or cause transmission constraints to bind at higher shadow price levels. Thus, a radial modeling of interchange scheduled over particular tie lines that may initially be adequate for the purpose of modeling congestion impacts on the CAISO system could become inadequate over time if transmission congestion patterns change. The considerations that the CAISO took into account in setting its priorities for improving modeling and pricing of interchange transactions are discussed in Mr. Rothleder and Dr. Price's testimony.

Q. WHY NOT HAVE A SINGLE PROXY BUS FOR EVERY BALANCING AUTHORITY AREA WITH WHICH AN RTO (USING LMP) IS INTERCONNECTED?

A. While it would generally be desirable to have no more than one proxy bus for each interchange schedule that is enforced in real-time (thus one proxy bus per Balancing Authority Area in the absence of controllable lines or special pricing agreements), implementing such a system would not be of equal importance at all locations. If power flowing over all of the contract paths between the other Balancing Authority Area and the CAISO have similar impacts on internal CAISO transmission constraints, or if the impacted constraints have very low shadow prices, then there will be little near-term benefit to improving the modeling of the pricing points.

Q. IF THESE INEFFICIENT SCHEDULING INCENTIVES ARE IMPORTANT, SHOULD MRTU START-UP BE DEFERRED UNTIL SUCH TIME AS THE CAISO IS ABLE TO IMPLEMENT ITS LONG-RUN PRICING MODEL AT EVERY INTERTIE POINT?

A. No. My understanding is that at this point in time, neither the CAISO nor any market participant has identified known problem areas for interchange pricing other than the pricing for the SMUD and TID Balancing Authority Areas. While it is possible that after MRTU start-up congestion patterns will become apparent that will make it important for the CAISO to expeditiously implement changes to its interchange pricing rules at additional tie line points, those situations have yet to be identified.

Deferring MRTU implementation will delay the important improvements to CAISO markets and dispatch procedures that will accompany MRTU implementation and deferring MRTU implementation would not provide the CAISO with any insights as to what intertie pricing issues will emerge under actual MRTU operation and which if any pricing points might need to be consolidated. In addition, until specific problems are identified either through analysis or actual operating experience, it is not clear what priority should be assigned to additional improvements in interchange pricing relative to other improvements in the MRTU market design or implementation.

Q. WOULD IT BE UNDULY DISCRIMINATORY FOR THE CAISO TO APPLY THE PROPOSED INTERCHANGE PRICING RULES TO TRANSACTIONS SCHEDULED AT THE SMUD-TID IBAA PRIOR TO THE TIME IT CONSOLIDATES OTHER TIE LINE PRICING POINTS?

A. No. The issue addressed by the CAISO pricing proposal for the SMUD-TID IBAA is the existence of inefficient scheduling incentives that would result in artificially high prices being paid for interchange schedules having contract paths for delivery at the SMUD or TID interchange scheduling points. If it is found that congestion patterns are such that similar inefficient scheduling incentives exist at other locations, then the CAISO will need to implement changes to its interchange pricing policies at other scheduling points to address those problems, but there is no discrimination in not yet having addressed a problem that has not yet been identified.

When PJM consolidated its southeast and southwest interface pricing points in 2006 to address the kind of inefficient scheduling incentives that concern the CAISO at the SMUD-TID IBAA, PJM did not similarly consolidate the IESO, Michigan and NYISO interface pricing points. That did not reflect discrimination, it merely reflected PJM's judgment was to the locations at which the inefficient scheduling incentives were a problem that needed to be addressed. The CAISO has made a similar judgment in proposing the pricing rules for the SMUD-TID IBAA. Like PJM, the CAISO may find a need to make changes over time to its interchange pricing rules, but this filing concerns the pricing policies that are known to be needed now, not the changes that may be identified as needed in the future.

III. THE IBAA PROPOSAL IS CONSISTENT WITH THE MECHANISMS USED BY OTHER RTOS TO MODEL AND PRICE INTERCHANGE TRANSACTIONS

Q. IS THE CAISO IBAA PRICING PROPOSAL CONSISTENT WITH THE METHODS THAT OTHER BALANCING AUTHORITIES USE TO PRICE SCHEDULED INTERCHANGE IN LMP BASED MARKET SYSTEMS?

A. Yes. All of the existing LMP-based pricing systems currently utilize proxy bus mechanisms for analyzing and pricing the congestion impacts of interchange schedules that are analogous to the methods the CAISO proposes to use to model and price scheduled interchange with the SMUD-TID IBAA.

The NYISO initially had four proxy buses, one each for modeling interchange with ISO-NE, Ontario, PJM and Hydro Quebec. Since NYISO start-up, four additional proxy buses have been added for the purpose of modeling the impact of power scheduled to flow over controllable lines (Direct Current (DC) lines or Phase Angle Regulated (PAR) controlled lines) or in one case in order to separately model wheel-through transactions that are subject to special coordination rules between PJM and NYISO. There is no instance in which the NYISO utilizes more than one proxy bus to model and price scheduled interchange over the free flowing ties with a single Balancing Authority Area.

PJM's proxy bus pricing system has undergone a number of changes since the implementation of LMP in 1998, reflecting the construction of a new DC line (Neptune), the westward expansion of PJM, and changes in proxy bus design. The Overall trend in PJM proxy bus pricing since 1998 has been to reduce the number of proxy buses, first to no more than one proxy bus per Balancing Authority Area, and PJM now typically uses a single proxy bus to price scheduled interchange with many distinct Balancing Authority Areas.

Until early 2001, PJM priced imports from and exports to New York based on prices determined for both a NYPP East and a NYPP West proxy bus. Thus, PJM had two proxy buses for a single Balancing Authority Area (the NYISO) and permitted market participants to designate either NYPP east or NYPP west as the source or sink of their transaction. Since the proxy buses were modeled as being at electrically distinct locations, the price at the NYPP west proxy bus reflected the value of power delivered into or exported from western PJM, while the price at the NYPP east proxy bus reflected the value of power delivered into or exported from eastern PJM. When PJM was constrained from west to east, imports from the NYPP east bus would appear more valuable than imports from the NYPP west bus, and conversely, exports to the NYPP east bus would appear more expensive. The fundamental problem with the application of this dual proxy bus system to the pricing of scheduled interchange with the NYISO was that, because the NYISO was a single Balancing Authority Area, PJM and the NYISO set a single interchange schedule and the designation of the source or sink of some transactions as being either NYPP east or west had no meaning for the dispatch of generation in either PJM or New York. Thus, the initial PJM proxy bus pricing system for the NYISO is the kind of system the SMUD-TID IBAA parties would have the FERC require the CAISO to use to price interchange with the SMUD and TID Balancing Authority Areas.

By late 2000 and early 2001, PJM and NYISO market participants had figured out that it was profitable to designate NYPP west as the sink for all exports, resulting in a lower price paid to PJM, and to designate NYPP east as the source for all imports, resulting in a higher price paid by PJM. PJM for example, calculated that over the period December 2000- February 2001, 97% of the transactions scheduled at the NYPP west proxy bus were exports from PJM and only 3% were imports, while 87% of the transactions scheduled at the NYPP east proxy bus were imports and only 13% were exports.[7] During the same hour, therefore, PJM was potentially selling power at a low

[7] Andy Ott, “Congestion Charges and Loopflow,” p. 5.

price for exports sinking at NYPP west and buying power at a high price for imports sourced at NYPP east, yet there might be no net interchange with the NYISO.

In early 2001 PJM recognized that the dual proxy bus system for an interface with a single Balancing Authority Area was exposing PJM consumers to significant real-time congestion rent shortfalls (and thus uplift costs) and the dual proxy bus was replaced on April 1, 2001 with a single proxy bus for the NYISO interface, consistent with the single interchange schedule agreed upon by PJM and the NYISO.

Since that time PJM has never had more than one proxy bus for the scheduling of interchange over the free flowing ties with a single adjacent Balancing Authority. Moreover, PJM has found that even having one proxy bus or pricing point for each Balancing Authority Area can be too many and has twice consolidated the pricing points for multiple Balancing Authority Areas.

After APS joined PJM on April 1, 2002, PJM had separate proxy buses for VACAR and AEP, along its southern and western edge. Dominion (VACAR) and AEP were separate Balancing Authority Areas so the separate proxy bus schedules had operational significance in terms of separate interchange schedules. In 2002 PJM found, based on e-tags, that many transactions being scheduled as sinking at the PJM VACAR interface were actually sourced in MAIN or ECAR and being scheduled on a contract path for delivery into PJM from VACAR. Thus, market participants were scheduling transactions along a contract path Main –VACAR – PJM, rather than along the contract path MAIN-PJM, presumably because the transmission charges to schedule along the contract path into VACAR were less than the difference in the PJM LMP price between the AEP and VACAR proxy buses. This contract path delivery location entitled the transactions to be paid the VACAR proxy bus price, but the actual electrical impact of the transactions on PJM constraints was much more like power delivered on the AEP interface.[8] In response to this problem PJM provided, effective July 19, 2002, that transactions scheduled to sink at the VACAR proxy bus but having an e-tag indicating an ECAR or MAIN source would be paid the price for the AEP bus, rather than the VACAR proxy bus.[9]

This change did not satisfactorily address the problem, however, and effective March 1, 2003 PJM combined the AEP and VACAR proxy buses.[10] The 2002 changes addressed the problem of individual transactions scheduled along a contract path from AEP into VACAR and then into PJM by using e-tags to identify transactions sourcing outside VACAR and to determine the pricing for such transactions. E-tags do not reveal where generation was actually incremented or decremented, as there could be two e-tags, one sourcing in ECAR and sinking in VACAR and another sourcing in VACAR sinking

---

8 PJM Market Monitoring Unit, "Report to the Federal Energy Regulatory Commission, Interface Pricing Policy," August 12, 2002, located at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/200208-report-ferc1.pdf.

9 PJM Market Monitoring Unit, email to Energy Market Committee, August 1, 2002; "Report to the Federal Energy Regulatory Commission, Interface Pricing Policy," August 12, 2002 and email to Energy Market Committee, August 27, 2002. PJM Market Monitoring Unit, 2002 State of the Market Report, pp. 56-60, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

10 PJM Market Monitoring Unit, "2003 State of the Market Report," pp. 95-96, 101-102; PJM Market Monitoring Unit, email to Energy Market Committee, January 9, 2003 "Report on Interface Pricing Policy," February 28, 2003.

in PJM. Given its inability, even using e-tag information, to distinguish interchange schedules that would produce an increase in generation within VACAR from those that would produce an increase in generation in AEP, PJM combined the interfaces for pricing purposes. PJM continued to separately conduct its check out with each Balancing Authority Area, but for the purpose of pricing the impact of transactions on its internal transmission constraints, PJM switched to using a single pricing point, eliminating the inefficient scheduling incentives of market participants that had arisen from the dual pricing points.

With the westward expansion of PJM, after AEP joined PJM, separate proxy buses were established for the Southwestern control areas (Cinergy, TVA, etc.) and the Southeastern control areas (Duke, etc.). While these new proxy buses spanned groups of Balancing Authority Areas, transactions scheduled from these regions turned out not to have distinguishable impacts on PJM transmission constraints, again because power scheduled to flow from the Southeast region into PJM, could ultimately be supported by generation increases in the Southwestern region scheduled into the Southeast region and then into PJM along a fictional contract path. When PJM was constrained from west to east and the Southeastern proxy bus price rose relative to the value of power from the Southwestern proxy bus, PJM found that transactions were sourced in the Southeast, but the actual powerflows over its lines were from the Southwest. On October 1, 2006, PJM's southeast and southwest interface pricing points were consolidated and separate proxy buses established for the pricing of imports and exports. Thus, it can be seen in the PJM experience that the kind of pricing system that the SMUD-TID IBAA parties would have imposed on the CAISO has repeatedly shown itself to be prone to the kind of inefficient scheduling practices that concern the CAISO.

Q. DOES ISO-NE USE MULTIPLE PROXY BUSES TO PRICE SCHEDULED INTERCHANGE OVER THE FREE FLOWING TIES WITH A SINGLE ADJACENT BALANCING AUTHORITY AREA?

A. No. Like NYISO and PJM, ISO-NE currently has no more than one proxy bus or pricing point for interchange transactions over the free flowing ties with an adjacent Balancing Authority Area. At present, ISO-NE has six proxy buses for interregional schedules, three with the NYISO, two with the Hydro Quebec, one with New Brunswick.[11] The ISO-NE proxy bus for its AC inter-connection with NYISO is located at Roseton. Like the NYISO, ISO-NE has a separate proxy bus located at Shoreham on Long Island for power scheduled to flow on the Cross Sound Cable, which is a controllable line (DC), and also has a separate proxy bus for schedules on the PAR controlled 1385 line connecting ISO-NE and Long Island. ISO-NE also has separate proxy buses for its two distinct DC interconnects with Hydro Quebec at Highgate and Sandy Pond. Finally, it has a proxy bus located at Keswick for deliveries from New Brunswick.

Q. IS THE CAISO SMUD-TID IBAA PROPOSAL THEREFORE CONSISTENT WITH EASTERN PRICING PRACTICES?

---

[11] "ISO New England Calculation of TTC for External Interfaces and ATC for PTF Interfaces," Version 2.0, Issued on December 15, 2007.

A. Yes. The CAISO's decision not to establish a separate pricing point for each interconnection with the SMUD and TID Balancing Authority Areas is consistent with the current practices of PJM, NYISO and ISO-NE and with the trend over time in their pricing of scheduled interchange. Moreover, the establishment of a single pricing point (the SMUD-TID IBAA) to price transactions with the SMUD and TID Balancing Authority Areas is consistent with the approach PJM has applied since 2003 to pricing transactions scheduled with Balancing Authority Areas on its southern border.

Q. IS THERE ANY PRECEDENT IN THE EASTERN RTOS FOR THE CAISO PROPOSAL TO ESTABLISH ADDITIONAL PRICING POINTS FOR SELLERS WITH RESOURCES LOCATED WITHIN THE SMUD AND TID BALANCING AUTHORITY AREAS THAT ARE WILLING TO PROVIDE ADDITIONAL INFORMATION TO THE CAISO?

A. Yes. The CAISO's proposal to establish additional pricing points for transactions sourced in the SMUD or TID Balancing Authority Areas – if the selling entities agree to provide additional information to the CAISO enabling the CAISO to have reasonable assurance that the transaction schedules will be supported by changes in generation within those Balancing Authority Areas – is also consistent with existing eastern practices.

During early 2007 PJM entered into Interface Pricing Arrangements with Duke Energy (January 5, 2007),[12] Progress Energy Carolinas (February 13, 2007)[13] and the

[12] Andrew L. Ott letter to Lance C. Stotts re: Duke Energy Carolinas Interface Pricing Arrangements, January 5, 2007, located at http://www.pjm.com/documents/downloads/agreements/duke-pricing-agreement.pdf.

North Carolina Municipal Power Agency Number 1 (March 19, 2007),[14] under which Duke, Progress and the North Carolina Municipal Power Agency can buy and sell power to PJM at prices calculated for generator nodes on their system (rather than the South IMP or South EXP proxy bus price).[15]

These agreements have a number of provisions limiting the circumstances in which the DECGen, PECGen, and NCMPAGen proxy prices will be applicable but the essence of these agreements is that these proxy bid prices will only be applicable if these entities are not purchasing power outside their Balancing Authority Area. The point of these restrictions is that if these entities are not purchasing power from outside their Balancing Authority Area, then any increase in exports to PJM must be supported by an increase in generation located within their Balancing Authority Area. Conversely, any decrease in imports from PJM must be supported by a decrease in generation within their Balancing Authority Area.

The DECGen, PECGen and NCMGen prices are not applicable when the relevant entities are purchasing power located outside their Balancing Authority Area because in those circumstances there is no assurance that generation will increase within the Duke,

---

[13] Andrew L. Ott letter to Robert Caldwell re: Progress Energy Carolinas, Inc. Interface Pricing Arrangements, February 13, 2007, located at http://www.pjm.com/documents/downloads/agreements/pec-pricing-agreement.pdf.

[14] Andrew L. Ott letter to Clay A. Norris re: North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement, March 19, 2007, located at http://www.pjm.com/documents/downloads/agreements/electricities-pricing-agreement.pdf .

[15] These agreements were also discussed in the 2007 State of the Market Report, pp. 212-213, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

Progress or North Carolina Municipal Power Authority Balancing Authority Areas to support these exports to PJM.

Under the agreements, Duke, Progress and the North Carolina Municipal Power Agency No. 1 agreed to provide confidential and auditable data to PJM concerning their load, aggregate system generation, aggregate energy sales and purchases on a one-minute or shorter basis. These agreements are an explicit model for the CAISO proposal and CAISO stakeholders were provided with weblinks to documents describing the PJM agreements so that they could better understand the proposed approach.

IV. CONCLUSION: THE IBAA PROPOSAL IS A REASONABLE MEANS OF MEETING CAISO OBJECTIVES AND IS A REASONABLE PROPOSAL FOR THE START OF MRTU OPERATIONS.

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE CAISO PRICING PROPOSAL FOR THE SMUD-TID IBAA?

A. First, the CAISO pricing proposal addresses inefficient pricing incentives that have repeatedly manifested themselves in eastern markets when market participants have been given the opportunity to use contract path scheduling practices to schedule transactions across multiple pricing points. Given the CAISO's assessment of the likelihood of material price differences, and the close proximity of the scheduling points at issue, there is no basis for inflicting the costs of these inefficient scheduling practices on CAISO consumers for even a short period of time.

Second, the CAISO pricing proposal is consistent with the evolution of eastern pricing systems, and the ability of sellers with resources located within the SMUD or TID Balancing Authority Areas to be paid an appropriately higher price if they are willing to provide additional information to the CAISO, will enable CAISO consumers to benefit from the CAISO's ability to pay appropriately higher prices for scheduled interchange supported by external generation having favorable impacts on internal CAISO transmission constraints without paying elevated prices for external generation having no such favorable effects.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER08-___-000**

I, Scott M. Harvey, declare under penalty of perjury, that the foregoing questions and answers labeled as the Testimony of Scott M. Harvey were prepared by me, with the assistance of others working under my direction and supervision; and that the facts contained in those answers are true and correct to the best of my knowledge, information and belief.

Executed on: June 10, 2008
Date

Scott M Harvey
Scott M. Harvey

Scott M. Harvey, Director, LECG

LECG
350 Massachusetts Avenue, Suite 300
Cambridge, Massachusetts 02139
Tel. (617) 761-0106
Fax (617) 621-8018
Email: sharvey@lecg.com

BIO/SUMMARY

Dr. Harvey has consulted on competition and market design in the electric power industry; gas pipeline rate and pricing issues; contract and transfer pricing; private antitrust litigation; and numerous mergers and acquisitions, particularly in the oil, gas pipeline and electric utility industries.

EDUCATION

Ph.D., Economics, University of California, Berkeley, with fields in industrial organization, econometrics and advanced theory

B.A., Economics, University of Illinois-Champaign-Urbana

PRESENT POSITION

LECG, Cambridge, MA, 1998 – present
Director

OTHER POSITIONS HELD

Putnam, Hayes & Bartlett, Inc., 1987 - 1998
Director

Bureau of Economics, U.S. Federal Trade Commission, 1977-1987

CONSULTING EXPERIENCE

Electric Utility

- Assisted in the preparation of the pool-based open access transmission tariffs of the Member Systems of the New York Power Pool and the PJM Supporting Companies, based on locational marginal pricing (LMP) and financial transmission rights.
- Worked with a coalition supporting the development of an LMP-based congestion management system in NEPOOL to reform NEPOOL's congestion management system.

- Assisted ISO New England with the development and implementation of a multi-settlement system for energy and ancillary services and a congestion management system based on LMP and financial transmission rights.
- Tested the pricing software of the NYISO prior to startup. After startup responsible for identification and correction of erroneous prices in NYISO settlements, and support of NYISO market monitoring unit, regulatory affairs and market relations.
- Assisted Midwest ISO with the development of its LMP-based long-term congestion management system and resource adequacy issues.
- Beginning in August 2004, began assisting the California ISO with the development and implementation of its LMP-based MRTU design and resource adequacy issues.
- Worked with RTOs on inter-control area coordination, transaction scheduling, pricing and resource adequacy issues.
- Advised electricity traders, retailers and IPPs on participation in restructured electricity markets in the United States.
- Worked with groups opposing creation of barriers to the entry of new generators in NEPOOL and California.
- Worked with coalitions` supporting reform of the California congestion management system (1999-2000).
- Participated in the review of electricity restructuring arrangements and market rules in New Zealand and Australia.
- Analyzed the potential for, and evidence of, the exercise of market power in deregulated electric generation markets.
- Analyzed the competitive effects of market power mitigation policies for electricity generation assets.
- Assisted RTOs with the analysis of credit issues relating to virtual trading and financial transmission rights.
- Assisted RTOs with the analysis of market performance issues.

Gas

- Analyzed the competitive forces affecting gas pipeline rates, both in the context of pipeline pricing strategies and in the context of FERC review of gas pipeline rates.
- Analyzed the competitive and price effects of price fixing agreements in the natural gas pipeline industry.
- Analyzed the actual and potential value of firm pipeline transmission capacity.
- Estimated the cost of abrogating natural gas contracts.
- Analyzed the competitive effects of actual and proposed acquisitions in the gas pipeline industry.
- Analyzed the accuracy of gas price indices.

Oil Industry

- Analyzed the competitive effects of actual or proposed acquisitions and joint ventures in the oil terminaling and marketing, oil refining and oil pipeline industries, including the Amoco-BP merger; the Texaco-Shell joint venture; the proposed Phillips-Conoco and Philips-Ultramar joint ventures; Sun Cos acquisition of Chevron's Philadelphia refinery and Atlantic Refining Co.; Williams Cos acquisition of the Oklahoma Mississippi River System and Marathon's acquisition of Rock Island Refining.
- Developed economic principles for the allocation of joint costs in the oil and gas producing industry.
- Developed estimates of the market price for ANS-type crude oil processed at refineries operated by ANS producers.
- Estimated the passthrough of crude oil price increases into refined product prices.

Other Antitrust and Merger Consulting Experience

- Analyzed the competitive effects of actual or proposed acquisitions and joint ventures in the float glass; residential and commercial roofing; electrical equipment; industrial controls; and chemical industries.
- Analyzed the competitive effects of partial equity interests and joint ventures in a variety of industries.
- Estimated the magnitude of alleged price fixing overcharges in a variety of industries.

GOVERNMENT EXPERIENCE

- Analyzed the competitive impact of many oil industry mergers and acquisitions, including Mobil Corporation's proposed acquisition of Marathon Oil; Gulf Oil's proposed acquisition of Cities Service Company; Texaco's acquisition of Getty Oil; and Chevron's acquisition of Gulf Oil.
- Analyzed the competitive impact of gas pipeline mergers and acquisitions including Internorth's acquisition of HNG; Midcon's acquisition of United Gas Pipe Line; and Occidental Petroleum's acquisition of Midcon.
- Participated in non-public investigations of predatory pricing, non-price predation, price fixing, monopolization and sham litigation in a variety of industries.
- Served as an economic advisor to Commissioner Azcuenaga.

PUBLICATIONS

"Transmission Capacity Reservations Implemented through a Spot Market with Transmission Congestion Contracts," with William W. Hogan and Susan L. Pope, *Electricity Journal*, Vol. 9, #9, November 1996.

"Mergers in the U.S. Petroleum Industry 1971-1984: An Updated Comparative Analysis," with Jay S. Creswell, Jr., and Louis Silvia. Bureau of Economics Staff Report to the Federal Trade Commission, May 1989.

U.S. Federal Trade Commission, Mergers in the Petroleum Industry, September 1982 (with others).

Petroleum Product Price Regulations: Output, Efficiency and Competitive Effects, with C. Roush. U.S. Government Printing Office, Washington D.C., 1981.

"Petroleum Product Price Regulations: Output and Efficiency Effects," with C. Roush. Carnegie Rochester Conference Series on Public Policy, Vol. 14, Spring 1981.

"Factors Leading to Structural Change in the U.S. Oil Refining Industry in the Postwar Period," with S. Peck. *Advances in the Economics of Energy Resources*, Vol. 1, 1979.

WORKING PAPERS AND REPORTS

Scott M. Harvey, Matthew Kunkle, Benjamin Hagberg, Alexis Maharam, Shaun Glassman and Christine Offerman, "Preliminary Report: Analysis Track Testing of CAISO MRTU Pricing and Dispatch," April 16, 2008.

Scott M. Harvey, "ISO-NE Capacity Market Design," Prepared for California Independent System Operator, October 9, 2007.

Scott M. Harvey, "PJM RPM Capacity Model," Prepared for California Independent System Operator, August 10, 2007.

Scott M. Harvey, Bruce M. McConihe and Susan Pope, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," November 20, 2006 (Revised June 18, 2007).

Scott M. Harvey, "Analysis of TCC Credit Policy Background," New York Independent System Operator, Inc., April 21, 2007 (Revised May 21, 2007).

Scott M. Harvey, "CAISO CRR Credit Requirements," California Independent System Operator, February 20, 2007.

Scott M. Harvey, Lorenzo Kristov and Mark Rothleder," Overview of CAISO Analysis of the Seams Issues Whitepaper prepared for the Control Area Coalition by ZGlobal Inc.," California Independent System Operator, January 16, 2007.

Scott M. Harvey, "Resource Adequacy Mechanisms: Spot Energy Markets and Their Alternatives," Center for Research in Regulated Industries, 19th Annual Western Conference, Monterey, California, Revised June 28, 2006.

David F. Babbel and Scott M. Harvey, "Evaluation of NYISO Virtual Trading Collateral Multiple Policy," New York Independent System Operator, Inc. January 31, 2006.

Scott M. Harvey, "CRR Study 2 Report Addendum," California Independent System Operator, September 30, 2005.

Scott M. Harvey, "Reserve Optimization Cost Savings," New York Independent System Operator, Inc., August 11, 2004 (revised September 19, 2005).

Scott M. Harvey, "ICAP Systems in the Northeast: Trends and Lessons," California Independent System Operator, September 19, 2005.

Scott M. Harvey and Susan L. Pope, "CRR Study 2: Evaluation of Alternative CRR Allocation Rules," California Independent System Operator, August 24, 2005.

Scott M. Harvey and Susan Pope, "Illustration of Issues Arising in CRR Allocation to LAPs," California Independent System Operator, July 1, 2005.

Scott M. Harvey and William W. Hogan, "Empirical Analysis of the Exercise of Market Power in California Electricity Markets," International Industrial Organization Conference, Industrial Organization Society, Atlanta Georgia, April 9, 2005.

Scott M. Harvey, Susan L. Pope and William W. Hogan, "Comments on the California ISO MRTU LMP Market Design," California Independent System Operator, February 23, 2005.

Scott M. Harvey, "Shortfall Allocation Methodology," New York Independent System Operator, Inc., February 15, 2005.

Scott M. Harvey, "Benefit Analysis and Cost Allocation for Regulated Transmission Investment," MISO, October 4, 2004.

Scott M. Harvey, "Internal NYISO DC Controllable Line Scheduling" Concept of Operation, New York Independent System Operator, May 4, 2004.

Scott M. Harvey and William W. Hogan, "Comments on CAISO CRR Auction and Allocation Issues," March 2, 2004.

Scott M. Harvey, William W. Hogan and Todd Schatzki, "A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," January 2, 2004.

Scott M. Harvey and Susan L. Pope, "Application of the Make-Whole Approach and Shortfall Reduction Procedure to the Day-Ahead Market and TCC Auction," NYISO Market Structures Working Group, October 17, 2003.

Scott M. Harvey, "FTR Hedging and Arbitrage," MISO CMWG, August 19, 2003.

Scott M. Harvey, "Proxy Buses, Seams and Markets," Draft, NYISO Market Structures Working Group, May 23, 2003.

Scott M. Harvey, "Illustrating Loss Residual Allocation Rules," Draft, Midwest ISO, March 28, 2003.

Scott M. Harvey, "Controllable Lines" Concept of Operation, New York Independent System Operator, January 8, 2003.

Scott M. Harvey, "Transmission Losses Pricing Examples," MISO Congestion Management System, January 3, 2003.

Scott M. Harvey and William W. Hogan, "Market Power and Market Simulations," July 16, 2002.

Scott M. Harvey and William W. Hogan, "Loss Hedging Financial Transmission Rights," January 15, 2002.

Scott M. Harvey and William W. Hogan, “Identifying the Exercise of Market Power in California,” December 28, 2001.

Scott M. Harvey and William W. Hogan, “Further Analysis of the Exercise of Market Power in the California Electricity Market,” November 21, 2001.

Scott Harvey and Susan L. Pope, “MSWG Expansion TCC Approach, Revised,” NYISO Market Structures Working Group, November 15, 2001.

Scott Harvey and Susan L. Pope, “TCC Awards for Transmission Expansion: Identification of Unresolved Issues in the Proposed MSWG Award Process,” NYISO Market Structures Working Group, November 15, 2001.

Scott M. Harvey, “Notes on Locational Market Power Mitigation,” November 7, 2001 (for Midwest ISO).

Andrew P. Hartshorn and Scott M. Harvey, “Assessing the Short-Run Benefits from a Combined Northeast Market,” October 23, 2001.

Scott M. Harvey, Susan L. Pope, John P. Buechler and Robert M. Thompson, “Feasibility Study for a Combined Day-Ahead Market in the Northeast,” May 4, 2001 (Draft Reports January 19, 2001 and April 20, 2001).

Scott M. Harvey and William W. Hogan, “On the Exercise of Market Power Through Strategic Withholding in California,” April 24, 2001.

Scott M. Harvey, “Uplift Allocation,” April 10, 2001 (for NYISO).

Scott M. Harvey and Andrew P. Hartshorn, “Inter-Regional Transaction Scheduling by the New York ISO,” January 2, 2001.

Scott M. Harvey, John D. Chandley and William W. Hogan, “Electricity Market Reform in California,” November 22, 2000.

Scott M. Harvey, “Real-Time Dispatch Alternatives,” November 20, 2000 (for Midwest ISO).

Scott M. Harvey, “Forward Schedules and Real-time Settlements,” November 20, 2000 (for Midwest ISO).

Scott M. Harvey and William W. Hogan, “Issues in the Analysis of Market Power in California,” October 27, 2000.

Scott M. Harvey and William W. Hogan, “California Electricity Prices and Forward Market Hedging,” October 17, 2000.

John D. Chandley, Scott M. Harvey and William W. Hogan, “Congestion Management in California,” August 31, 2000.

Scott M. Harvey and William W. Hogan, “Comments on the Congestion Management Proposals of the California ISO,” August 31, 2000.

Michael D. Cadwalader, Scott M. Harvey, William W. Hogan and Susan L. Pope, "Coordinating Congestion Relief Across Multiple Regions," October 7, 1999.

Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, "Preliminary Report - Phase IV Market Trials," October 8, 1999.

Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, "Report on Phase III Market Trials," September 17, 1999.

Michael D. Cadwalader, Scott M. Harvey, William W. Hogan and Susan L. Pope, "Market Coordination of Transmission Loading Relief Across Multiple Regions," November 18, 1998.

Michael D. Cadwalader, Scott M. Harvey, William W. Hogan and Susan L. Pope, "Reliability, Scheduling Markets and Electricity Pricing," May 1998.

Scott M. Harvey, William W. Hogan and Susan L. Pope, "Transmission Capacity Reservations Implemented Through a Spot Market with Transmission Congestion Contracts," July 9, 1996 (revised versions, various dates).

Scott M. Harvey, William W. Hogan and Susan L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," June 1996 (revised versions, various dates).

CONFERENCE AND OTHER PUBLIC PRESENTATIONS

Scott M. Harvey, "Proxy Bus Pricing Mechanisms and the CAISO's Proposed Pricing System for Integrated Balancing Area Authorities," Prepared for the California ISO Board of Governor Meeting, May 21, 2008.

Scott M. Harvey, "Analysis Track Testing of CAISO MRTU Pricing and Dispatch, Preliminary Results," Prepared for the California ISO Board of Governor Meeting, May 21, 2008.

Scott M. Harvey, "The Role of Demand in Generation Investment and Portfolio Planning," Presented at Infocast's Energy and Generation Planning Summit, Denver, Colorado, May 14, 2008.

Scott M. Harvey, "Analysis Track Testing of CAISO MRTU Pricing and Dispatch," Prepared for the California ISO, April 22, 2008.

Scott M. Harvey, "Review of Eastern Proxy Bus Mechanisms," Prepared for the California ISO, April 11, 2008.

Scott M. Harvey, "Analysis of Midwest ISO Congestion Rent Shortfalls," prepared for Midwest ISO Market Subcommittee, March 4, 2008.

Scott M. Harvey, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," Harvard Electricity Policy Group Conference, Los Angeles, California, December 6, 2007.

Scott M. Harvey, "Scarcity Pricing in New York and New England," Prepared for California Independent System Operator, November 1, 2007.

Scott M. Harvey and Cleve Tyler, "Market-Based Pricing for Ancillary Services," EUCI Ancillary Services Conference, Minneapolis, MN, September 11, 2007. Presented at conference by Cliff Hamal and Cleve Tyler.

Scott M. Harvey, "Reliability, Ancillary Service Markets and Scarcity Pricing," EUCI Ancillary Services Conference, Minneapolis, MN, September 11, 2007. Presented at conference by Cleve Tyler.

Scott M. Harvey, "Economic Perspectives on the Valuation of Financial Transmission Rights," EUCI Conference on The Impact of New FERC Filing and FASB Fair Valuation Standards on Power Industry Accounting, Chicago, IL, July 30, 2007.

Scott M. Harvey, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," Center for Research in Regulated Industries, Rutgers University, 20th Annual Western Conference, Monterey, CA, June 28, 2007.

Scott M. Harvey, "Credit Policy for Financial Transmission Rights," EUCI, National Perspectives on Financial Transmission Rights, March 20, 2007.

Scott M. Harvey, "Resource Adequacy in the West," Infocast Western Power Supply Forum II, San Francisco, CA, December 5, 2006.

Scott M. Harvey, "The Role of Markets and Market Design in Supporting Reliability," EUCI Transmission Reliability Conference, Arlington, VA, October 18, 2006.

Scott M. Harvey and Arun Sharma, "Market-Based Pricing for Ancillary Services," EUCI Ancillary Services Conference, Atlanta, GA, September 2006.

Scott M. Harvey, "The Role of Ancillary Services Markets in Supporting Resource Adequacy," EUCI Ancillary Services Conference, Atlanta, GA, September 28, 2006.

Scott M. Harvey, "Resource Adequacy Mechanisms: Spot Energy Markets and Their Alternatives," Center for Research in Regulated Industries, 19th Annual Western Conference, Monterey, California, June 28, 2006.

Scott M. Harvey, "Reforming Point-to-Point and Network Service," Infocast OATT Reform Conference, Washington, DC, June 9, 2006.

Scott M. Harvey and Susan L. Pope, "Defining and Implementing Transmission Maintenance Performance Incentives in LMP Markets," Infocast Transmission Summit 2006, March 15, 2006.

Scott M. Harvey, "Federal Electricity Regulation and Alternative Energy: The Good, the Bad and the Ugly," American Bar Association Section of Environment, Energy and Resources Teleconference, December 14, 2005.

Scott M. Harvey, "Transmission Investment and the Obligation to Serve," EUCI: Transmission Investments and Reliability Conference, Brewster, MA, September 26, 2005.

Scott M. Harvey and Susan L. Pope, "CRR Allocation Methodology Examples," California Independent System Operator, August 31, 2005.

Scott M. Harvey, "Final CRR Study 2 Results," California Independent System Operator, August 31, 2005.

Scott M. Harvey and Susan L. Pope, "Expanded CRR Study 2 Results," California Independent System Operator, August 18, 2005.

Scott M. Harvey and Susan L. Pope, "CRR Allocation Rules: Discussion of Eligible LSE CRR Sources," California Independent System Operator, July 14, 2005.

Scott M. Harvey and Susan L. Pope, "CRR Study 2 Metrics and CRR Allocation by Eastern and Midwestern ISOs," California Independent System Operator, June 21, 2005.

Scott M. Harvey, "Mergers and Market Power in the Electric Power Industry," International Industrial Organization Conference, Industrial Organization Society, Atlanta, Georgia, April 9, 2005.

Scott M. Harvey, "RTO Performance, Governance and Independence," EUCI: The Organization and Governance of the Market Agent, Washington, DC, March 30-31, 2005.

Scott M. Harvey, Susan L. Pope and William W. Hogan, "Comments on ISO MRTU LMP Market Design," California Independent System Operator, March 2, 2005.

Scott M. Harvey and Dmitri Perekhodtsev, "Market-Based Pricing for Ancillary Services," EUCI Ancillary Services Conference, Denver, CO, January 21, 2005.

Scott M. Harvey, "Competitive Ancillary Services Markets: Lessons Learned," EUCI Ancillary Services Conference, Denver, CO, January 20, 2005.

Scott M. Harvey, "Hedging Pseudo Tie Transmission Usage," Midwest Market Initiative, Market Subcommittee, November 2, 2004.

Scott M. Harvey and Matthew D. Kunkle, "Market-Based Pricing for Ancillary Services," EUCI Ancillary Services Conference, Cambridge, MA, March 19, 2004.

Scott M. Harvey, "Competitive Ancillary Services Markets: Lessons Learned," EUCI Ancillary Services Conference, Cambridge, MA, March 17, 2004.

Scott M. Harvey, "Coordinating Dispatch Between Regions," Infocast: Transmission Summit 2004, Washington, D.C., January 29, 2004.

Scott M. Harvey, William W. Hogan and Todd Schatzki, "A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," Competition and Coordination in the Electric Industry, Conference, Institute for Industrial Economics/Centre for Economic Policy Research, Toulouse, France, January 16-17, 2004.

Scott M. Harvey, "Consumer Impact of LMP Pricing," Midwest ISO, Minneapolis, Minnesota, October 20, 2003.

Scott M. Harvey, "The Virtues of Virtual RTOs," Harvard Electricity Policy Group, September 26, 2003.

Scott M. Harvey, “Electricity Market Dynamics in the Northeast,” Northeast Gas Association, Gas & Power in the Northeast Conference, Westborough, MA, September 25, 2003.

William Barber, Robert Thompson and Scott Harvey, “Virtual Regional Dispatch – Adding Real-time Cross Border Financial Rights to the Proposed Design,” ISO-NE Markets Committee, NYISO Market Structures Working Group, September 11, 2003.

Scott M. Harvey, “Scarce Pipeline Capacity and High Prices: Will FERC Put the Lights Out in the Northeast?” Infocast: Northeast Gas Storage and Supply Strategies 2003 Conference, June 17, 2003.

Scott M. Harvey, “State of Northeast Power Markets,” Connecticut Power and Energy Society, Northeast Energy and Commerce Association, 10th Annual New England Energy Conference, Mystic, Connecticut, June 3, 2003.

Scott M. Harvey, “Proxy Buses and Seams,” Joint Meeting of ISO-NE Markets Committee and NYISO Market Structures Working Group, May 29, 2003.

Scott M. Harvey, “RMR Issues Under LMP,” Midwest Market Initiative (MISO), March 20, 2003.

Scott M. Harvey, “Inter-ISO Dispatch Proposal,” NEPOOL Markets Committee, February 11, 2003.

Scott M. Harvey and Matthew D. Kunkle, “LMP and Financial Transmission Rights,” EUCI Transmission Pricing Conference, Denver CO, January 24, 2003.

Scott M. Harvey, “LMP in the West,” EUCI Transmission Pricing Conference, Denver CO, January 22-23, 2003.

Scott M. Harvey and William W. Hogan, “Mitigating Locational Market Power,” PJM Local Market Power Mitigation Working Group, Wilmington, Delaware, January 21, 2003.

Scott M. Harvey, “Inter-ISO Dispatch Proposal,” NYISO Market Structures Working Group, January 14, 2003.

Scott M Harvey, “Day-Ahead Markets, Unit Commitment and Congestion,” Infocast: Standard Market Design Conference, Washington, D.C., December 5, 2002.

Scott M Harvey, “Issues in LMP Implementation,” Infocast: Standard Market Design Conference, Washington, D.C., December 5, 2002.

Scott M. Harvey, “Transmission Losses Pricing,” MISO Congestion Management System, Carmel, IN, November 21, 2002.

Scott M. Harvey, “Ancillary Service Markets under SMD,” CBI Standard Market Design Conference, Arlington, VA, November 19, 2002.

Scott M. Harvey, “Can LMP Work Outside the Northeast?” CBI Standard Market Design Conference, Arlington, VA, November 18, 2002.

Scott M. Harvey, "Consumer Friendly Markets: What Should Consumers Really Want?" Elcon: Coping with Uncertainty and Volatility Conference, Washington, D.C., October 10, 2002.

Scott M. Harvey and Cliff W. Hamal, "Market-Based Pricing of Ancillary Services: Market Design Choices, Consequences and Performance," EUCI Ancillary Services Conference, Atlanta, GA, September 27, 2002.

Scott M. Harvey, "Ancillary Services, Shortages and Market Power," EUCI Ancillary Services Conference, Atlanta, GA, September 27, 2002.

Scott M. Harvey, "Open Access, LMP and Retail Sales," NARUC Summer Meeting, Portland, OR, July 29, 2002.

Scott M. Harvey, "Prices, Market Power and Market Structure," Infocast: Standard Market Design Conference, Chicago, IL, June 18, 2002.

Scott M. Harvey, "RTOs and Standard Market Design," Restructuring Transmission Operations, Center for Business Intelligence, Alexandria, VA, April 22, 2002.

Scott M. Harvey, "Standard Market Design for Ancillary Services," EUCI Ancillary Services Conference, Denver, CO, April 10, 2002.

Scott M. Harvey, "Congestion Management Workshop," MISO Congestion Management System, Dallas, Texas, March 14, 2002.

Scott M. Harvey, "Congestion Management Workshop," MISO Congestion Management System, Minneapolis, Minnesota, February 15, 2002.

Scott M. Harvey, "TCC Expansion Awards for Controllable Devices: Initial Discussion," NYISO Market Structures Working Group, February 12, 2002.

Scott M. Harvey, "Incentive Systems for Transmission Owner Maintenance Activities," MISO Congestion Management System, Carmel, IN, January 31, 2002.

Scott M. Harvey, "Multiple Element Constraints," MISO Congestion Management System, Carmel, IN, January 31, 2002.

Scott M. Harvey and Susan L. Pope, "Financial Transmission Rights in MISO: Allocation Issues and Process," MISO Congestion Management System, Transmission Rights Allocation Task Force, January 30, 2002.

Susan L. Pope and Scott M. Harvey, "Financial Transmission Rights in MISO – Overview of Allocation Process and Issues," MISO Transmission Rights Task Force, Carmen, IN, January 10, 2002.

Scott M. Harvey, "Financial Transmission Right Obligation and Option Auctions," MISO Congestion Management System, Carmel, IN, November 29, 2001.

Scott M. Harvey, "Transmission Reservations for Regulation," MISO Congestion Management System, Carmel, IN, November 28, 2001.

Scott M. Harvey and Susan L. Pope, "TCC Expansion Awards for Controllable Devices: Initial Discussion," NYISO Market Structures Working Group, November 16, 2001.

Scott M. Harvey and Susan L. Pope, "MSWG Expansion TCC Award Process, Task 1: Resolution of Ambiguities," NYISO Market Structures Working Group, November 16, 2001.

Scott M. Harvey, "Standard Market Design for RTOs," Infocast: FERC RTO Initiative Conference, Washington, DC, November 13, 2001.

Scott M. Harvey, "Trading Hub Concepts," MISO Congestion Management System, Carmel, IN, November 1, 2001.

Scott M. Harvey, "Reserve Market Issues in the Northeast," EUCI Ancillary Services Conference, Denver, CO, October 31, 2001.

Scott M. Harvey, "Ancillary Services: What Works, What Doesn't, New Issues," EUCI Ancillary Services Conference, Denver, CO, October 31, 2001.

Scott M. Harvey, "Electricity Market Lessons: What Works and What Does Not," EUCI Electric Power Market Performance Conference, Denver, CO, September 21, 2001.

Scott M. Harvey, "Creating Market-Driven Incentives for Transmission Expansion," EUCI Electric Power Market Performance Conference, Denver, CO, September 21, 2001.

Scott M. Harvey, "Generation Interconnection and Transmission Expansion," MISO Congestion Management System, Carmel, IN, September 20, 2001.

Scott M. Harvey, "Day-Ahead Scheduling Process," MISO Congestion Management System, Carmel, IN, September 6, 2001 (revised).

Scott M. Harvey, "Embedded Cost Recovery and Transmission Right Allocation," MISO Congestion Management System, Carmel, IN, September 6, 2001 (revised).

Scott M. Harvey, "Two-Settlement Systems in PJM and New York," MISO Congestion Management System, Carmel, IN, August 2, 2001.

Scott M. Harvey, "The Role of Local Control Areas and MISO II," MISO Congestion Management System, Carmel, IN, August 2, 2001.

Scott M. Harvey, "The Role of Local Control Areas and MISO," MISO Congestion Management System, Carmel, IN, July 19, 2001.

Scott M. Harvey, "FTR Auction Basics," MISO Congestion Management System, Carmel, IN, July 12, 2001.

Scott M. Harvey, "Review of Flowgate Design Choices III," MISO Congestion Management System, Carmel, IN, July 12, 2001.

Michael D. Cadwalader and Scott M. Harvey, "Review of Flowgate Design Choices II," MISO Congestion Management System, Carmel, IN, June 21, 2001.

Scott M. Harvey, "Real-Time Pricing and Dispatch," MISO Congestion Management System, Carmel, IN, June 21, 2001.

Scott M. Harvey, "FTR Basics," MISO Congestion Management System, Carmel, IN, June 21, 2001.

Michael D. Cadwalader and Scott M. Harvey, "Review of Flowgate Design Choices," MISO Congestion Management System, Carmel, IN, June 14, 2001.

Scott M. Harvey, "LMP Basics," MISO Congestion Management System, Carmel, IN, June 14, 2001.

Scott M. Harvey, "Pre-Scheduling of External Transactions in New York," NYISO Market Structures Working Group Meeting, April 6, 2001.

Scott M. Harvey, "Lessons from Competitive Ancillary Service Markets," EUCI Ancillary Services Conference, Denver, CO, April 4, 2001.

Scott M. Harvey, "Feasibility Study for a Regional Day-Ahead Electricity Market in the Northeast," NERC ESC/OSC Meeting, San Antonio, TX, March 14, 2001.

Scott M. Harvey and Herb Yan, "Congestion Management Basics," EUCI Congestion Management Conference, Denver, CO, February 7, 2001 (talk given by John D. Chandley).

Scott M. Harvey, "Detecting the Exercise of Market Power," Infocast: Price Spikes, Caps and Market Power Conference, Washington, DC, January 26, 2001.

Scott M. Harvey, "Fundamentals of Market Power Definition, Detection and Mitigation," Infocast: Price Spikes, Caps and Market Power Conference, Washington, DC, January 24, 2001.

Scott M. Harvey, "NYISO Market Issues," FERC Technical Conference, Washington, DC, January 21, 2001.

Scott M. Harvey, "Price Corrections Process," FERC Technical Conference, Washington, DC, January 21, 2001.

Scott M. Harvey, "Real-Time Dispatch Procedures," Midwest ISO, Congestion Management Working Group, Indianapolis, IN, November 14, 2000.

Scott M. Harvey, "RTO Formation: Lessons from Experience to Date," EEI, RTO Filings Conference, Washington, DC, November 3, 2000.

Scott M. Harvey, "Flowgate Rights and Congestion Management," EEI, RTOs and Market Design Conference, Washington, DC, September 28, 2000.

Scott M. Harvey and Andrew P. Hartshorn, "Market Based Pricing for Ancillary Services: Market Design Choices, Consequences and Outcomes," EUCI Ancillary Services Conference, Denver, CO, September 15, 2000.

Scott M. Harvey, "Ancillary Service Prices in Open Access Markets During the Summer of 2000," EUCI Ancillary Services Conference, Denver CO, September 14, 2000.

Scott M. Harvey, William W. Hogan and John D. Chandley, “A Reform Proposal and A Review of the CAISO Staff Proposals,” California Congestion Management, Folsom, CA, September 6, 2000.

Scott M. Harvey, “Lessons in Congestion Management, What Works and What Doesn’t,” EUC Congestion Management Conference, Denver, CO, June 22-23, 2000.

Scott M. Harvey, “Market Based Congestion Management,” EUC Congestion Management Conference, Denver, CO, June 22-23, 2000.

Scott M. Harvey, “Locational Reserve Examples,” New York Reserve Working Group, May 15, 2000.

William W. Hogan, John D. Chandley, Scott M. Harvey and the California Reform Coalition, “Reform of the California Electricity Market: A Path Forward,” March 30, 2000.

Scott M. Harvey, “Fundamentals of Congestion Pricing,” California Reform Coalition, March 28, 2000.

Scott M. Harvey, “Lessons to Date from Financial Rights Auctions in New York and PJM,” Infocast’s Auctioning and Using Financial Transmission Rights Conference, Philadelphia, PA, February 24, 2000.

Scott M. Harvey, “Overview of the Structure of Financial Rights Auctions in PJM, NY, and NEPOOL,” Infocast’s Auctioning and Using Financial Transmission Rights Conference, Philadelphia, PA, February 24, 2000.

Scott M. Harvey, “Comparing the Rules and Regulations for Financial Rights in PJM, NY, NEPOOL and California,” Infocast’s Auctioning and Using Financial Transmission Rights Conference, Philadelphia, PA, February 24, 2000.

Scott M. Harvey, “Transmission Access and Risk,” Infocast’s Portfolio Analysis and Management Conference, Houston, TX, February 17, 2000.

Scott M. Harvey, “Market Structure and Portfolio Risk,” Infocast’s Portfolio Risk Analysis and Management Conference, Houston, TX, February 17, 2000.

Scott M. Harvey, “Market Based Pricing for Ancillary Services,” EUCI Conference, Denver, CO, February 4, 2000.

Scott M. Harvey, “Ancillary Service Markets in the Northeast,” EUCI Conference, Denver, CO, February 3, 2000.

Scott M. Harvey, “Illustrative Causes for Price Corrections,” New York Independent System Operator, January 28, 2000.

Scott M. Harvey and William W. Hogan, “Imperfect Pricing for Imperfect Markets,” Harvard-Japan Project on Energy and the Environment, Tokyo, Japan, January 2000.

Scott M. Harvey, “Validation of SCUC and SCD Prices,” NY TIE Group Meeting, December 15, 1999.

Scott M. Harvey, “The RTO NOPR and Congestion Management,” Infocast’s Update on FERC’s RTO Initiative Conference, Washington, DC, November 4, 1999.

Scott M. Harvey and Andrew P. Hartshorn, "Transmission Congestion and Ancillary Services," Infocast Conference – Ancillary Services in Competitive Markets, San Francisco, CA, October 22, 1999.

Scott M. Harvey, "Ancillary Services in New England and New York," Infocast's Ancillary Services in Competitive Markets Conference, San Francisco, CA, October 20-22, 1999.

Scott M. Harvey, "Electricity Deregulation," Federal Reserve Bank of New York, Buffalo Branch, Understanding Our Electricity Cost and the Impact of Deregulation Conference, Canisius College, Buffalo, NY, October 20, 1999.

Scott M. Harvey, "Locational Reserve Constraints," NEPOOL Joint CMS/MSS Working Group, October 14, 1999.

Scott M. Harvey, "Reserve Scheduling Proposal," NEPOOL Joint CMS/MSS Working Group, October 13, 1999.

Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, "Review of Phase IV Market Trials," Prepared for New York ISO – Market Participants Meeting, October 11, 1999.

Scott M. Harvey, "Distributed Generation: Market Rules and Market Penetration," Electric Utility Consultants – Distributed Generation Conference, Denver, CO, September 22, 1999.

Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, "Review of Phase III Market Trials," Prepared for New York ISO – Market Participants Meeting, September 21, 1999.

Scott M. Harvey, "Production Cost Models and the Forward Price Curve," Electric Utility Consultants Electricity Market Pricing Conference, Vail, CO, August 9, 1999.

Scott M. Harvey, "Transmission Pricing in the New World." Workshop, Electric Utility Consultants Deregulation Progress Report: Issues and Insights Conference, Vail, CO, August 6, 1999.

Scott M. Harvey, "How are Installed Capacity Markets Working, and Where are they Going?" Electric Utility Consultants Deregulation Progress Report Conference, Vail, CO, August 5, 1999.

Scott M. Harvey, Susan L. Pope and Andrew P. Hartshorn, "Allocation of Financial Transmission Rights in California, New York and PJM," NEPOOL Joint CMS/MSS Group, August 4, 1999.

Scott M. Harvey, Andrew P. Hartshorn and Mark Rossi, "Four-Hour Option Market," NEPOOL Joint CMS/MSS Group, August 4, 1999.

Scott M. Harvey and Andrew P. Hartshorn, "Comparison of Unit Commitment Processes in Other Markets," NEPOOL Joint CMS/MSS Group, August 4, 1999.

Scott M. Harvey, Susan L. Pope and Andrew P. Hartshorn, "Nodal-Zonal Pricing Part II – Zonal FCRs," NEPOOL Joint CMS/MSS Group, August 4, 1999.

Scott M. Harvey and Susan L. Pope, "A Nodal-Zonal Pricing System," NEPOOL Joint CMS/MSS Group, July 19, 1999.

Scott M. Harvey, "Market Power Mitigation, Transmission Constraints and Congestion Pricing," Infocast – Impact of Market Power on Competitive Energy Markets Conference, Washington, DC, July 15, 1999.

Scott M. Harvey, "FCR Auction Mechanics," NEPOOL Joint CMS/MSS Group, July 7, 1999.

Scott M. Harvey and Andrew P. Hartshorn, "Reliability Commitment Issues," NEPOOL Joint CMS/MSS Group, June 14, 1999.

Scott M. Harvey, "Ancillary Services in a Two Settlement System – Part II," NEPOOL Joint CMS/MSS Group, June 10, 1999.

Scott M. Harvey, "Financial Transmission Rights (FCRs)," NEPOOL Joint CMS/MSS Group, June 10, 1999.

Scott M. Harvey and Susan L. Pope, "Ancillary Services in a Two-Settlement System," NEPOOL Joint CMS/MSS Group, May 27, 1999.

Scott M. Harvey and Susan L. Pope, "Reliability Commitment and Scheduling Issues," NEPOOL Joint CMS/MSS Group, May 27, 1999.

Scott M. Harvey, "Congestion Pricing, Financial Rights and MAPS," 1999 GE MAPS User's Conference, May 20, 1999.

Scott M. Harvey and Susan L. Pope, "Overview of the Straw Proposal," NEPOOL Joint CMS/MSS Group, May 10, 1999.

Scott M. Harvey and Susan L. Pope, "Market Hubs and Transaction Scheduling," NEPOOL Joint CMS/MSS Group, May 10, 1999.

Scott M. Harvey, "Understanding the Fundamentals of Congestion Pricing," Infocast – Independent Transmission Companies: A Better Alternative to ISOs? Conference, Las Vegas, NV, April 7, 1999.

Scott M. Harvey, "Designing an Auction for the Sale of Transmission Congestion Contracts," Infocast – Congestion Management Conference, Washington, DC, March 26, 1999.

Scott M. Harvey, "Understanding the Fundamentals of Congestion Pricing," Infocast – Congestion Management Conference, Washington, DC, March 24, 1999.

Scott M. Harvey, "Competitive Markets for Ancillary Services," Infocast – Merchant Plant Development Conference, Chicago, IL, March 23, 1999.

Scott M. Harvey, "Generation Asset Valuation: The Effects of Transmission Congestion and Congestion Pricing Systems," Infocast – Merchant Plant Development Conference, Chicago, IL, March 23, 1999.

Scott M. Harvey, "Lessons from the Summer of 1998," Washington Legal Forum on Electric Power Restructuring, American Conference Institute, Washington, DC, February 18, 1999.

Scott M. Harvey, "The Role of Distributed Generation in Competitive Electricity Markets," Electric Utility Consultants Distributed Electric Generation Conference, Denver, CO, January 26, 1999.

Scott M. Harvey and William Hogan, "A Congestion Management System for NEPOOL," December 21, 1998.

Scott M. Harvey and William W. Hogan, "Transmission Pricing for Competitive Generation Markets," Prepared for GPU PowerNet, Electricity Network Transmission Pricing Conference, Australian Competition and Consumer Commission, University of Melbourne, Australia, December 14, 1998.

Scott M. Harvey, "Is the Price Right?" ICM Conferences – Independent System Operators Conference, Chicago, IL, November 13, 1998.

Scott M. Harvey and Michael D. Cadwalader, "Understanding Transmission," Pasha Publications – Power Mart 98, Houston, TX, October 26, 1998.

Scott M. Harvey, "Locational Pricing," Pasha Publications – Electricity Regulation Conference, Alexandria, VA, October 7, 1998.

Scott M. Harvey and Susan L. Pope, "Locational Pricing," NEPOOL Regional Market Operations Committee and NEPOOL Regional Transmission Operations Committee, Westborough, MA, September 25, 1998.

Scott M. Harvey, "Summer of 1998, Market Design or Market Power," Infocast – Congestion Pricing and Tariffs Conference, Washington, DC, September 24, 1998.

Scott M. Harvey, "Locational Pricing: The Basics," Infocast – Congestion Pricing and Tariffs Conference, Washington, DC, September 23, 1998.

Scott M. Harvey and Susan L. Pope, "Locational Pricing," NEPOOL Regional Transmission Planning Committee, Westborough, MA, September 8, 1998.

Scott M. Harvey "Transmission Pricing and Production Modeling in the Competitive World," Infocast – Market Price Forecasting Conference, New York, NY, August 6, 1998.

Scott M. Harvey, "Congestion Pricing in PJM," Electric Utility Consultants – Transmission Pricing Conference, Denver, CO, June 25, 1998.

Scott M. Harvey, "Transmission Congestion: Strategies for Risk Mitigation in PJM," Pasha Publications/MW Daily – PJM Power Conference – Philadelphia, June 18, 1998.

Scott M. Harvey, "Buying and Selling Power Through the PJM Energy Market," Infocast – Taking Advantage of Electricity Choice in Pennsylvania and New Jersey, Philadelphia, PA, June 9, 1998 (talk given by Susan L. Pope and Mike D. Cadwalader).

Scott M. Harvey, "The New PJM ISO: How it Works and the Impact on Retail Markets," Infocast – Taking Advantage of Electricity Choice in Pennsylvania and New Jersey, Philadelphia, June 8, 1998.

Scott M. Harvey, "Bilateral Trading Under Locational Spot Pricing," Ontario Market Design Committee, Toronto, May 29, 1998.

Scott M. Harvey, Susan L. Pope and Michael D. Cadwalader, "Understanding Transmission," Pasha Publications/MW Daily, Ercot Power Markets Conference, March 31, 1998.

Scott M. Harvey, "Congestion Pricing After November 25, 1997," Electric Utility Consultants, ISO and Related Transmission Pricing Conference, March 18, 1998.

Scott M. Harvey, "Locational versus Zonal Pricing," Infocast, Congestion Pricing and Tariffs Conference, January 22, 1998.

Scott M. Harvey, "FTRs and the FTR Auction Mechanism," PJM Energy Market Committee, January 21, 1998.

Scott M. Harvey, "A Multi-Settlement System for PJM under LMP," PJM Energy Market Committee, October 30, 1997.

Scott M. Harvey, "What Role for the ISO?" Electric Utility Consultants, Independent System Operators Conference, October 2, 1997.

Scott M. Harvey, "Open Access, Spot Markets and the Role of the ISO in New York," Arizona Corporation Commission, Desert Star Meeting, Phoenix, May 29, 1997.

Scott M. Harvey, "Geographic Market Definition in Electricity Generation," Ex Net Market Power Conference, October 28, 1996 (talk was given by Susan Pope).

Scott M. Harvey and Susan L. Pope, "The Impact of Alternative Electricity Market Structures on Stranded Generation Costs," IBC Stranded Costs Conference, June 20, 1996.

Scott M. Harvey, "Modeling Competitive Electricity Markets with MAPS-MWFLOW," GE MAPS West Coast Users Conference, May 1996.

TESTIMONY

Scott M. Harvey, Advantage Energy versus New York ISO, American Arbitration Association, Case No. 13 198 J 02911 06 (on behalf of New York Independent System Operator, Inc.) Report: June 18, 2007; Deposition: July 26, 2007; Rebuttal Report: September 5, 2007; Cross-Examination, October 17, 2007.

Scott M. Harvey, FERC Technical Conference re: New York Independent System Operator, ER07-521-000, Transcript, September 10, 2007.

Scott M. Harvey, Docket Nos. ER07-613-___ and ER07-___-000, CRR Credit Requirements (on behalf of California Independent System Operator Corporation), June 22, 2007.

Scott M. Harvey, Public Service Commission of West Virginia Case No. 06-________, re: Application for Waiver of Modification Requirements for a Siting Certificate (on behalf of Longview Power LLC), November 3, 2006.

Scott M. Harvey, Public Service Commission of West Virginia Case Nos. 05-1467-CN; 03-1860-E-CS, Rebuttal Testimony re: Siting Certificate for Exempt Wholesale Generating Facility in Monongalia County, West Virginia, (on behalf of Longview Power LLC), March 16, 2006.

Scott M. Harvey and Susan L. Pope, Docket No. ER06-615-000, California Independent System Operator Corporation Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade, Attachment G, "Direct Testimony of LECG's Scott Harvey and Susan Pope on Congestion Revenue Rights and Related Market Design Issues" (on behalf of California Independent System Operator Corporation), February 9, 2006.

Scott M. Harvey, Docket No. ER06-615-000, California Independent System Operator Corporation Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade, Attachment H, "Direct Testimony of LECG's Scott Harvey on how the CAISO has addressed issues in the February 2005 MRTU Report" (on behalf of California Independent System Operator Corporation), February 9, 2006.

Scott M. Harvey and David F. Babbel, Docket No. ER05-941-00, re: Evaluation of NYISO Virtual Trading Collateral Multiple Policy (on behalf of New York Independent System Operator, Inc.), January 31, 2006.

Scott M. Harvey and William W. Hogan, Docket ER02-1656-026, Further Amendments to the California Independent System Operator Corporation's Amended Comprehensive Market Design Proposal, Attachment D, "Comments of Scott M. Harvey and William W. Hogan on the California ISO's Proposed Hour-Ahead Scheduling Process" (on behalf of California ISO), May 12, 2005.

Scott M. Harvey, Docket No. EL04-115-000, ER-04-983-000, "Request for Settlement Conference, Alternative Request for Approval of Remedial Plan and Proposed Tariff Revisions, and Emergency Request for Expedited Action of the New York Independent System Operator, Inc." (on behalf of New York Independent System Operator, Inc.), July 2, 2004.

Scott M. Harvey, Expert Statement, ICC Case No. 12400/JNK, *Morgan Stanley Capital Group Inc. & MSDW Power Development Corporation v. Kansai Power International & KPIC North America Corporation* and ICC Case No. 12402/JNK, *Kansai Power International & KPIC North America Corporation v. Morgan Stanley Capital Group Inc.* (on behalf of Morgan Stanley), October 27, 2003.

Scott M. Harvey and William W. Hogan, "Order Seeking Comments on Proposed Revisions to Market-Based Rate Tariffs and Authorizations," Attachment A. FERC Docket Nos. EL01-118-000 and EL01-118-001 (on behalf of American National Power, Inc., PPL Energy Plus, LLC and Sempra Energy), August 18, 2003.

Scott M. Harvey, Prepared Direct Testimony in Response to I.02-11-040, Price Reporting (on behalf of SoCalGas and SDG&E), June 11, 2003.

Scott M. Harvey and Andrew P. Hartshorn, Docket No. ER03-766-000, re: Scarcity Pricing Proposals (on behalf of New York Independent System Operator, Inc.), April 23, 2003.

Scott M. Harvey and William W. Hogan, Docket EL02-60-003, et al., Prepared Answering Testimony, re: Long-Term Contracts (on behalf of Morgan Stanley Capital Group, Inc., Sempra Energy Resources, and Mirant Americas Energy Marketing, L.P.), March 20, 2003.

Scott M. Harvey and William W. Hogan, Docket EL00-95-075, Prepared Answering Testimony, re: California Refund (on behalf of Mirant Americas Energy Marketing L.P., Mirant California, LLC, Mirant Delta, LLC and Mirant Potrero, LLC), March 20, 2003.

Scott M. Harvey, Attachment I, Docket No. ER97-1523-068, et al., Motion of the New York Independent System Operator, Inc. and the New York Transmission Owners for Leave to Supplement the Record, re: Marginal Losses (on behalf of NYISO and New York Transmission Owners), March 3, 2003.

Scott M. Harvey and William W. Hogan, Docket No. EL-00-95-075, Prepared Direct Testimony, re: California Refund (on behalf of Mirant Americas Energy Marketing L.P., Mirant California, LLC, Mirant Delta, LLC and Mirant Potrero, LLC), March 3, 2003.

Scott M. Harvey, *PacifiCorp*, Docket No. EL02-80-000, et al. (consolidated), Prepared Direct Testimony, October 8, 2002, Prepared Answering Testimony, November 26, 2002, Cross-Examination, December 18, 2002, re: Forward Contracts (on behalf of Morgan Stanley Capital Group Inc., Reliant Energy Services, Inc., and Williams Energy Market & Trading Co.).

Scott M. Harvey and William W. Hogan, Public Utilities Commission of the State of California, Docket No. EL02-60-003, et al. (consolidated), Prepared Direct Testimony, October 17, 2002, Prepared Rebuttal Testimony, November 14, 2002, Cross-Examination, December 9, 2002, re: Forward Contracts (on behalf of Morgan Stanley Capital Group Inc., Sempra Energy Resources, Mirant Americas Energy Marketing, L.P. and Allegheny Energy Supply Company).

Scott M. Harvey and William W. Hogan, *Nevada Power Co. and Sierra Pacific Power Co.*, FERC Docket No. EL02-06-000, et al., Prepared Answering Testimony, August 27, 2002, Prepared Direct Testimony, June 28, 2002, re: Forward Contracts (on behalf of Morgan Stanley Capital Group Inc., Mirant Americas Energy Marketing, LP, American Electric Power Service Corporation and Reliant Energy Services).

Scott M. Harvey and William W. Hogan, Docket No. ER02-2081-000, re: Fixed Block Generation Pricing (on behalf of New York ISO), June 12, 2002.

Michael D. Cadwalader, Scott M. Harvey and William W. Hogan, Docket Nos. EL00-95-001, ER02-1656-000, "Review of the California ISO's MD02 Proposal" (on behalf of IEPA), June 4, 2002.

Scott M. Harvey, William W. Hogan and Susan L. Pope, "Electricity Market Design and Structure: Working Paper on Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design," FERC Docket No. RM01-12-000, May 1, 2002.

Scott M. Harvey and William W. Hogan, "Forward Contracts," FERC Docket Nos. EL02-60-000 and EL02-62-000 (not consolidated), March 22, 2002 (on behalf of Coral Power, Constellation, GWF Energy and Sempra Energy).

Scott M. Harvey and William W. Hogan, "Market Power and Withholding," Docket No. EL-01-118-000, December 20, 2001 (on behalf of EEI and Dynegy, Inc).

Scott M. Harvey and Andrew P. Hartshorn, *New York Independent System Operator,* Docket Nos. ER00-3038-000, El00-70-000, EL00-70-001, August 25, 2000 (on behalf of New York ISO) RE: "Fixed Block Generation Pricing."

Scott M. Harvey and Andrew P. Hartshorn, *New York Independent System Operator* Docket Nos. EL00-70-000, EL00-67-000, May 31, 2000 (on behalf of New York ISO) "Comment on Scheduling of External Transactions and Price Volatility."

Scott M. Harvey, *New York Independent System Operator* Docket Nos. ER97-1523-011, OA97-470-010, ER97-4234-008, ER97-1523-018, OA97-401-017, ER97-4234-015, ER97-1523-019, OA97-470-

018, ER97-4234-016, Direct, May 8, 2000, Reply, August 25, 2000, Rebuttal, September 8, 2000, Cross-Examination, September 13-14, 2000 (on behalf of Member Systems and New York ISO) RE: Pricing of Marginal Losses.

Scott M. Harvey and William W. Hogan, *New England PowerPool,* Docket No. ER00-2016-000, "Comment on Congestion Management and Multi-settlement System Proposal," April 20, 2000 (on behalf of ISO New England).

Scott M. Harvey, FERC Docket EL00-49-000, *NRG Power Marketing, Inc. v. New York Independent System Operator, Inc.*, re: Price Corrections (on behalf of New York Independent System Operator, Inc.), March 3, 2000.

Scott M. Harvey and William W. Hogan, *California Independent System Operator Corporation,* Docket No. ER00-703-000, "Nodal and Zonal Congestion Management and the Exercise of Market Power: Further Comment," February 11, 2000 (on behalf of Sempra Energy).

Scott M. Harvey and William W. Hogan, *California Independent System Operator Corporation,* Docket No. ER00-703-000, "Nodal and Zonal Congestion Management and the Exercise of Market Power," January 10, 2000 (on behalf of Sempra Energy).

Scott M. Harvey and William W. Hogan, *California Independent System Operator Corporation,* Docket No. ER99-3339-000, "Comment on the California ISO's Request for Rehearing," October 29, 1999 (on behalf of Coalition Supporting Pro-Competitive Interconnection Policies), Re Amendment 19.

Scott M. Harvey and William W. Hogan, *California Independent System Operator Corporation*, Docket No. ER99-3339-000, "Further Comments on the California ISO's NewGen Policy," August 23, 1999 (on behalf of Calpine), Re Amendment 19.

Scott M. Harvey and William W. Hogan, *California Independent System Operator Corporation*, Docket No. ER99-3339-000, "Comments on the California ISO's NewGen Policy," July 27, 1999 (on behalf of Coalition Supporting Pro-Competitive Interconnection Policies), Re Amendment 19.

PJM Interconnection, L.L.C.; Docket No. ER98-3527-000, Before FERC, April 1999 (on behalf of PJM Market Participant Group), Re Bid Disclosure Requirement.

Scott M. Harvey and William W. Hogan*, Old Dominion Electric Cooperative v. PJM Interconnection*, L.L.C., Docket No. EL99-000, 1998 (on behalf of PJM supporting companies).

Sunrise Energy Management, Inc., Sunrise Energy Marketing Co., Consolidated Fuel Corp., and Sunrise Energy Co.; Case No. 394-36780-SAF-11, U.S. Bankruptcy Court, Northern District of Texas, Dallas Division, 1995 (on behalf of Northwest Pipeline).

Chateaugay et al., Debtors; Case No. 86 B 11270, U.S. Bankruptcy Court, Southern District of New York, 1992 (on behalf of LTV secured bondholders).

Proxy Buses and Congestion Pricing of
Inter-Balancing Authority Area Transactions

Scott Harvey[1]

June 9, 2008

I. OVERVIEW

The most fundamental of all seams issues is the need of adjacent balancing authority areas to coordinate their net interchange. One aspect of this coordination involves the evaluation of the impact of incremental net interchange on congestion on transmission constraints within the scheduling balancing authority areas.[2] If there is no transmission congestion and no impact on system losses, the value of interchange power can be assessed merely by comparing the incremental dispatch cost within the receiving balancing authority area to the offer price of the imported power. If there is transmission congestion, however, then the scheduling of interchange power may not entail simply backing down the highest cost generation within the receiving balancing authority area but may require dispatching down a combination of low and high cost internal generation or even dispatching some high cost internal generation up out of merit to reduce flows on potentially overloaded transmission elements. Hence the evaluation of the value of interchange power requires assessment of the extent to which the imported power would allow the receiving balancing authority area to decrement high cost versus low cost internal generation.

Because power flows over all parallel paths from source to sink, an evaluation of the congestion impacts of imported power requires an assessment by the importing balancing authority area of the source of the imported power (i.e., the location at which generation would be incremented or decremented to support a change in net interchange). While all system operators carry out such an evaluation, they do not all use the same methods. Non-RTO system operators, for example, in some cases use ad hoc subjective methods to evaluate these congestion impacts, and these methods can be a source of concerns regarding the potential for discrimination. RTO system operators, on the other hand, tend to use model-based methods for evaluating such congestion impacts, particularly since under market-based systems, it is necessary for settlement purposes to either price interchange power or to price the transmission service used to deliver the power to load (including transmission congestion costs), as well as simply scheduling it.

All of the existing LMP based pricing systems currently utilize proxy bus mechanisms for analyzing and pricing the congestion impacts of interchange schedules. A fundamental feature of LMP pricing systems is that when transmission constraints are binding, location matters, and this

1 An earlier (May 23, 2003) version of this paper benefited from the comments of Rick Gonzales, William W. Hogan, Chuck King, Brad Kranz, Dave Laplante, Andy Ott and Susan Pope. Matthew Kunkle, Tomasz Gruzska and Elish Benthall assisted with the research for this update. The views presented here are not necessarily attributable to any of those mentioned, and any errors are solely the responsibility of the author.

2 There are also mechanisms to account for the impact of interchange transactions on transmission congestion within control areas that are not on the contract path, i.e., parallel flows in balancing authority areas not involved in scheduling a transaction. This paper focuses on the impacts on the scheduling balancing authority areas.

is true for the location of external as well as internal generation. The location and number of proxy buses used by LMP pricing systems to model imports and exports has been a subject of continuing discussion and evolving practice since the initial implementation of LMP pricing in PJM on April 1, 1998.

This paper describes the purpose and operation of proxy bus pricing systems, discusses the issues relating to the choice of proxy bus location and the number of proxy buses, and reviews the evolution of the proxy bus systems employed by NYISO, PJM, and ISO-NE and discusses the reasons behind the changes over time in proxy bus design. The paper focuses on five important features of proxy bus pricing and scheduling systems:

- The purpose of modeling changes in scheduled net interchange with an adjacent balancing authority area as sourcing or sinking at a proxy bus is to approximate the combined effect on congestion within the modeling balancing authority area (i.e., the change in flows on binding transmission constraints secured by the modeling balancing authority areas) of all changes in generation in the adjacent balancing authority area that would occur in response to a change in scheduled net interchange between the modeling balancing authority area and the adjacent area.

- The appropriate number of proxy buses depends, in part, on the number of separate tie line schedules that are managed by the system operators.

- Defining proxy bus locations in excess of the number of tie line schedules managed by system operators introduces the potential for significant market inefficiency. The cost of this inefficiency will typically be borne, at least in part, by power consumers in one or both of the affected balancing authority areas.[3]

- If there are multiple balancing authority areas along a common interface, defining individual proxy buses for each balancing authority area can lead to significant inefficiency, even if there is a distinct interchange schedule with each balancing authority area. As above, the cost of this inefficiency will typically be borne by power consumers in the importing or exporting balancing authority area.

- Proxy bus pricing systems are typically based upon network models that include all or portions of the transmission system in adjacent balancing authority areas.

Two important themes that emerge from this discussion are:

- There is no single proxy bus location that will be ideal from the standpoint of modeling the impact of changes in scheduled interchange on transmission congestion over all hours of the year and over all system conditions. It will be necessary to choose a proxy bus that provides the best approximation of actual system impacts under likely system conditions.

---

[3] Depending on the details of the RTO market design, these costs could be manifested in higher energy prices, in congestion rent shortfalls, or in real-time uplift costs.

- It will be difficult to assess ex ante the best location for a proxy bus and the ideal location may change over time with changes in the generation mix in external regions, changes in dispatch and transmission scheduling practices in the adjacent balancing authority area, and changes in market participant behavior. The location of a proxy bus may need to be modified over time based on operating experience to reflect these kinds of changes in the operational environment.

Proxy bus pricing systems are used both to price interchange between market and non-market regions and between market regions that utilize coordinated redispatch, such as PJM and MISO. In order to keep the scope of this paper manageable, it focuses on proxy bus pricing as applied between regions that do not utilize coordinated redispatch.

Section II explains the role of proxy buses in valuing imports and exports in LMP markets and discusses the issues that arise in determining the appropriate number and location of proxy buses. Section III describes the proxy buses utilized by PJM, the NYISO and ISO-New England, and discusses how they have evolved over time to address the issues discussed in Section II. Section IV briefly discusses the establishment of proxy buses for controllable lines. Section V contains examples illustrating the issues discussed in Section II.

II. PROXY BUS PRICING IN LMP MARKETS

A. General Principles

A proxy bus in eastern LMP based transmission pricing systems is a location at which generation in an adjacent balancing authority area is modeled for congestion pricing purposes (for the purpose of analyzing the impact of changes in net interchange on transmission congestion internal to the scheduling balancing authority area) as incremented to support imports from and decremented to allow exports to that adjacent balancing authority area. More specifically, the proxy bus is the location at which the dispatch and pricing models assume that generation in the adjacent balancing authority area is increased to support exports from that balancing authority area and decreased to accommodate imports into that balancing authority area. Importantly, the proxy bus location is typically not a delivery or metering point for net interchange power, does not necessarily correspond to the location of the Balancing Authority Operator with whom transaction checkout is conducted, and is not used to enforce contract path scheduling limits.

In LMP pricing systems the proxy bus is typically not simply an interface scheduling location modeled as radially connected to the ISO-coordinated transmission system (unless, of course, the adjacent system is connected via a single radial line).[4] Except in the case of controllable lines, it is also not the location at which interchange flows are metered. Instead, the transmission grid model employed by LMP based pricing systems extends beyond the internal ISO-coordinated transmission grid and represents, sometimes in a simplified or equivalenced manner, the transmission network in adjacent dispatch regions. An increase or decrease in generation at an

---

[4] Consistent with its zonal pricing model, the California ISO has until now represented external locations as radially connected to the California grid and not taken account of the impact of external transactions on interzonal congestion.

external proxy bus will therefore generally be modeled as potentially impacting the flows on multiple free-flowing tie lines (lines connecting the balancing authority area).[5] External proxy buses are locations on this external transmission grid that have been selected by the modeling balancing authority area for calculating the likely impact on the transmission system flows of the modeling balancing authority area of the combined effect of all changes in generation in the external region that would occur to support changes in the level of scheduled net interchange with the modeling balancing authority area.

The distinction between internal generation and load that are modeled at their actual location on the grid, and imports and exports which are modeled at a proxy bus arises because, under current dispatch procedures, a system operator (regardless of whether that system operator is an ISO/RTO or a vertically integrated balancing authority area) typically does not control the location at which generation in an adjacent balancing authority area is increased or decreased to support changes in net interchange.[6] That is, if the system operator in balancing authority area A accepts schedules for an additional 100 MW of imports from adjacent balancing authority area B, the system operator of balancing authority area A would not determine which specific generating units in balancing authority area B would be incremented to support the 100 MW change in net interchange. This would be determined either by the system operator dispatching balancing authority area B or the entity scheduling generation to support the interchange schedule. The pattern of power flows over free-flowing tie lines, and the impact on transmission constraints internal to balancing authority area A associated with a change in scheduled net interchange between balancing authority areas A and B may, however, depend on the specific location at which generation will be incremented in balancing authority area B. In analyzing the impact of this change in net interchange on its transmission constraints, and thus in both analyzing reliability impacts and valuing the interchange power, the system operator dispatching balancing authority area A must therefore make assumptions regarding the location at which the generation in balancing authority area B would be incremented to support exports to balancing authority area A.[7]

An external proxy bus is, in essence, the location at which the system operator assumes (for the purpose of modeling the congestion impacts on transmission lines within its balancing authority area) that generation in the adjacent balancing authority area will be dispatched up and down in

---

5 It is important to recognize that these models do not assume that *all* generation and load in the adjacent dispatch region is located at the proxy bus. Generation and load may be modeled as spread out over the transmission grid of the adjacent dispatch system for the purpose of modeling loop flows. The proxy bus simply models the location at which *marginal* changes in generation are assumed to occur in response to marginal changes in net interchange.

6 An exception is that the location of generation supporting dynamic schedules is known, and the output supporting the dynamic schedule is metered so dynamic interchange schedules need not be priced at a proxy bus.

7 Conversely, in order to analyze the impact of increased exports on transmission congestion within balancing authority area B, the system operator of exporting balancing authority area B must make assumptions regarding the locations at which the system operator for balancing authority area A would decrement generation in response to an increase in imports.

conjunction with changes in scheduled net interchange with that balancing authority area.[8] This is the case both for system operators in LMP markets and non-RTO system operators who also must use some set of assumptions if they are to analyze the impact of changes in net interchange on their internal transmission constraints. In an LMP market these calculated congestion impacts are also used to price imported and exported power, and to determine congestion charges on transmission schedules.

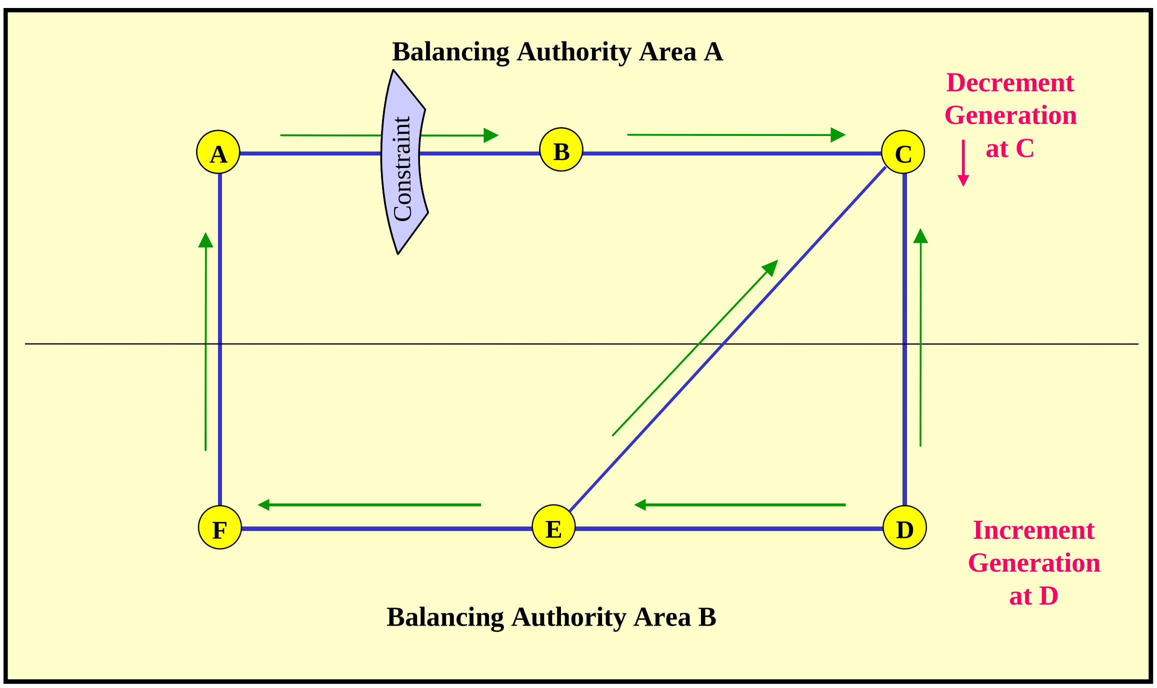
It is important in understanding the use of proxy buses to analyze congestion impacts to recognize that system operators cannot, in general, base their analysis of congestion impacts for a particular hour or dispatch interval on the observed flows on interregional tie lines attributable to a particular source of interregional transactions or to particular changes in net interchange during that period. This is because the flows observed on free-flowing interregional tie lines generally depend not only on net interchange between the directly interconnected balancing authority areas (and the location of the generation within those balancing authority areas used to support the change in net interchange) but also on the pattern of generation to meet load within each of the connected balancing authority area (which create loopflows through the adjacent interconnected balancing authority area) and the pattern of generation throughout the rest of the AC interconnection (which creates additional loopflows on the free-flowing tie lines). Thus, for example, the pattern of flows observed on the AC ties between PJM and NYISO depends not only on the location of generation used to support any change in net interchange between NYISO and PJM during a particular hour, but also on the pattern of generation and load within PJM (which would give rise to loop flows through NYISO), the pattern of generation and load within NYISO (which gives rise to loopflows through PJM), and the generation and load patterns throughout the rest of the eastern interconnection (which also gives rise to loopflows on the ties lines between NYISO and PJM).

Because the observed pattern of tie line flows depends on both unobserved loop flows arising from the dispatch and interchange of other balancing authority areas in the eastern interconnection and on the generation used to support scheduled interchange with a particular balancing authority area, it is not possible to directly determine from these total flows the location of the generation in the exporting balancing authority area that was used to support a change in net interchange or to identify the flows attributable specifically to the interchange schedule during a particular period. One can, however, analyze the relationship over time between changes in flows and changes in net interchange and draw conclusions regarding the typical location in an adjacent balancing authority area of the generation used to support exports or decremented to allow imports. Or, as discussed below, one can apply rules to the observed flows to calculate proxy bus prices that vary, albeit imperfectly, with changes in external generation sources and powerflows.

[8] The IDC used in the eastern interconnection to analyze the impact of loopflows associated with inter-control area transactions on off-contract path transmission systems for security coordination purposes (TLRs) also embodies a set of assumptions regarding the locations within a control area at which generation would be incremented or decremented to support a particular transaction. The scope of this paper is limited to the proxy bus mechanisms used by eastern RTOs; however, some of the limitations of the TLR process are related to the issues discussed in this paper.

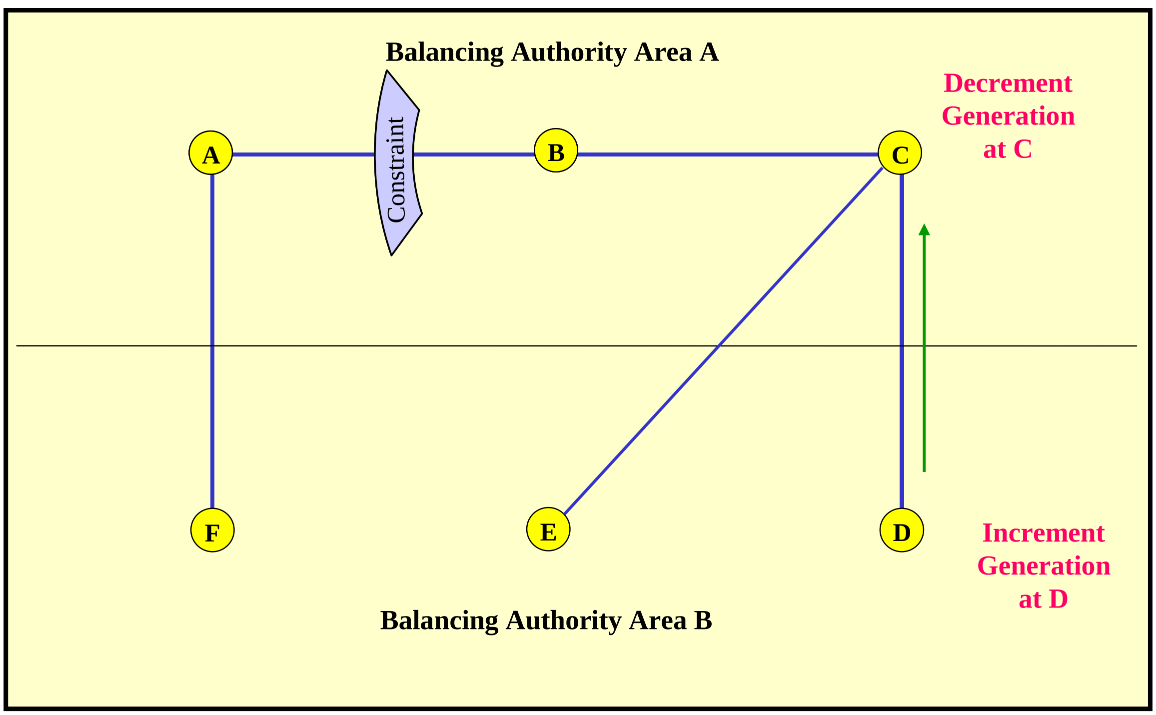
A proxy bus pricing system for scheduled net interchange also differs, except in the case of controllable lines, from modeling imports and exports as flowing over radially connected individual tie lines into the receiving balancing authority area. Under a proxy bus system, changes in scheduled interchange with an adjacent balancing authority area will be modeled for the purpose of analyzing impacts on internal transmission constraints as causing a change in the flows over all of the free flowing tie lines connecting the two balancing authority areas. Thus, as illustrated in Figure 1, if generation were incremented at D and decremented at C, the change in net interchange would cause power to flow over all of the parallel paths between D and C, including the transmission constraint between A and B. The value of an increase in net interchange with balancing authority area B supported by an increase in generation at D would be less than the value of an increase in net interchange supported by an increase in generation at C because more lower cost power at A, rather than high cost power at C, would have to be dispatched down to accommodate the impact of the imports on the constrained line A-B.

Figure 1
Proxy Bus Analysis of Congestion Impacts



Under a radial model of balancing authority area interconnections, on the other hand, the change in interchange would be scheduled to flow over individual tie line and the congestion impacts would be modeled based on this assumption. The external loops between F and E and E and D that were included in Figure 1 would be removed and locations D, E and F would be modeled as radially connected to North ISO, as shown in Figure 2. With such a model, if an increase in net interchange were scheduled over line D-C and high-cost generation at C decremented, there would be no impact on the flows over the line A-B, so the value of net interchange scheduled over the D-C line would be exactly the same as the value of power at C. The problem with this modeling approach from the standpoint of modeling congestion impacts for both reliability and pricing purposes is that while D is radially connected to C in the model portrayed in Figure 2, D is not radially connected to C in the actual power grid portrayed in Figure 1. As a result, in the real world, some of the net interchange scheduled on line D-C would in reality flow around over A-B to C, so balancing authority area A would find it necessary to back down some lower cost generation at A to accommodate the imports without overloading line A-B.

Figure 2
Radial Model Analysis of Congestion Impacts



Because external proxy buses are simply generation locations within a transmission network model, an LMP-based market system can calculate an LMP price for each external proxy bus. The LMP price at a proxy bus modeled by a given ISO will reflect the impact of net generation at the proxy bus location on transmission constraints within the region dispatched by that.[9]

9 For regions that include the cost of marginal losses in location prices (currently NYISO, ISO-NE, MISO and PJM) the determination of the LMP price at a proxy price differs from the calculation of internal LMP prices in that the LMP price at the proxy bus includes the marginal cost of losses incurred on flows from the proxy bus to

Importantly, except in regions with coordinated dispatch (such as PJM and MISO) , the LMP price at the proxy bus will not reflect the impact of generation at the proxy bus location on transmission constraints within the dispatch region with which interchange is being coordinated, those constraint imports would be managed by the other system operator.[10]

PJM, NYISO, ISO-NE and MISO all use proxy bus methods to model and price net interchange with adjacent balancing authority areas.

B. Proxy Bus Pricing Issues

Important market design issues involving proxy buses in LMP based transmission pricing systems are the location selected for the proxy bus and the determination of the appropriate number of proxy buses for representing transactions with adjacent balancing authority areas or balancing authority areas.

The discussion below explains why in practice, except in the case of radially connected dispatch regions, no single proxy bus location will provide a perfect representation, under all conditions, of the changes in line flows associated with a change in scheduled net interchange with that balancing authority area. The location of the proxy bus in any single proxy bus pricing system is therefore necessarily a compromise that will not be ideal over all system conditions. There are, however, a number of elements of flexibility within a single proxy bus pricing system can be utilized to better approximate the actual system impacts of changes in scheduled net interchange.

This section then turns to a discussion of the problems that result from the use of multiple proxy buses to price a single interchange schedule over free-flowing ties with an adjacent balancing authority area. The choice of a single versus multiple proxy bus location for scheduling inter-balancing authority area transactions is an often misunderstood element of electricity market design. While it might seem that the introduction of multiple proxy buses that allows market participants to choose the proxy bus used to schedule their transactions might provide a better approximation of system impacts than a single proxy bus model, this is not the case; in fact, just the reverse will generally be the case. It is seen that such a multiple proxy bus design will likely provide market participants with financial incentives to schedule transactions such that the proxy bus used to schedule their transactions does not reflect the actual location of the generation that would be dispatched to support the transaction. Moreover, this effect is systematic, causing a system operator employing a multiple proxy bus system to price scheduled net interchange in a manner that incurs costs that must be recovered from market participants in uplift charges. Despite the approximations inherent in a single proxy bus system, no more than one proxy bus should be established to price a single interchange schedule with an adjacent balancing authority area.

---

the border of the balancing authority area using the proxy bus model, but includes only the cost of losses that would be incurred on transmission facilities within that control area.

10 For the sake of simplicity, and because it is not relevant to current WECC practices, this paper does not discuss proxy bus pricing of interchange between regions that have implemented such market-to-market redispatch.

Finally, we turn to a related case, in which there is only one proxy bus for each adjacent balancing authority area or balancing authority area, but there are multiple, interconnected adjacent balancing authority areas or balancing authority areas scheduling interchange that impact a common interface. It is seen that this situation can give rise to many of the same problems as a multiple proxy bus system, and that these problems will likely become more acute as the level of pancaked rates falls or as the level of internal control area congestion rises. Thus, it can be necessary and appropriate to establish even fewer proxy buses than the number of interchange schedules established for a common interface.

Single Proxy Bus System

Under a single proxy bus system, all interchange scheduled with an adjacent balancing authority area is assumed to result in changes in net generation at the location of the proxy bus. Thus, increased imports from that balancing authority area are modeled as resulting in an increase in generation at the proxy bus location and decreased imports (or increased exports) are modeled as resulting in a decrease in generation at the proxy bus location. If there were no binding transmission constraints within the importing balancing authority area, the location at which generation would be increased in the adjacent dispatch area would be of no consequence to the area, as changes in the pattern of power flows would not matter to the importing balancing authority area from either a cost or reliability standpoint. This would also be the case if there were binding transmission constraints within the modeling balancing authority area but all generation within the adjacent balancing authority area had the same impact on these constraints.

The selection of the proxy bus location is important because a single proxy bus used to manage a single interchange schedule with an adjacent balancing authority area can fail to produce the optimal level of net interchange with respect to congestion impacts if three conditions hold:

- The proxy bus, and thus the assumed location of marginal generation in the adjacent balancing authority area, does not correspond to the actual location of marginal generation in the adjacent balancing authority area;
- The modeling balancing authority area has binding transmission constraints; and
- The change in flows on these binding constraints depends on the location at which generation is increased or decreased in the adjacent balancing authority area to support changes in net interchange.

If the modeling balancing authority area has binding transmission constraints and the change in flows on these binding constraints depends on the location at which generation is increased or decreased in the adjacent balancing authority area to support changes in net interchange, then the location of the proxy bus selected by the modeling balancing authority area matters. If the difference between the proxy bus location and the actual location at which generation is incremented in the other balancing authority area to support a change in net interchange is such that the actual change in generation has a less favorable impact on binding transmission constraints than would generation located at the proxy bus, then the proxy bus representation would cause the system operator to overvalue imports from the adjacent balancing authority area and hence to pay too much for imported power (or collect too little in congestion charges on the imports), likely scheduling more imports than is actually economic, or perhaps even feasible from a reliability perspective. This situation would result in real-time revenue inadequacy for the importing (modeling) ISO as day-ahead or hour-ahead schedules would have to be backed down or supported by out-of-merit real-time redispatch to eliminate the infeasibilities resulting from the import schedules, while the import price would have been set too high for the congestion charges on these imports to pay for this redispatch. For example, in Figure 1 above, if the proxy bus were defined at bus D, but generation were actually incremented at location F, an increase in imports from control area B would have a greater than modeled effect on the constraint A-B, allowing less generation at C to be dispatched down that would have assumed in determining the interchange price based on the proxy bus at D.

Alternatively, if the generation actually incremented to support changes in interchange has a more favorable effect on the binding transmission constraints than generation located at the proxy bus location, then the proxy bus price would be understated (i.e., not reflect the actual value of imports) and would tend to cause fewer imports to be scheduled than would be economic. This would correspond in Figure 1 to a situation in which the proxy bus was located at bus F, but generation were actually incremented at bus D, so that less power than modeled would flow over the constraint A-B, allowing more high cost generation at C to be backed down than was assumed in determining the interchange schedule or setting the interchange price. Under most ISO settlement systems this second kind of error would not be manifested in revenue inadequacy in ISO congestion rent settlements but would mean that load has not have been met at least cost.

In the single balancing authority area, single interchange schedule context, the choice of proxy bus location should be guided by several considerations. First, the location of load and fixed generation is irrelevant for the marginal analysis by the importing region of changes in line loadings in response to changes in scheduled interchange. The location of generation that is relevant to the pricing and scheduling of incremental net interchange and the selection of a proxy bus is the location at which marginal generation would be dispatched up or down in response to changes in the level of net interchange.[11] Thus, it is desirable that the location of the proxy bus used to model the impact of changes in scheduled interchange with an adjacent balancing authority area represent as well as possible the impact on tie line flows of dispatching marginal generation up or down in the adjacent dispatch area in response to changes in the level of net interchange.

Since each system operator would dispatch its resources to meet load, including net exports, at least cost, the generation that would be dispatched up to support exports would be the lowest cost undispatched generation, given load levels and transmission constraints within the exporting balancing authority area. The location of the lowest cost undispatched marginal generation in an adjacent balancing authority area is not fixed, but instead will depend on the level of load within the exporting balancing authority area and the location of transmission constraints within the exporting balancing authority area. As a result, the location of marginal generation within an

[11] The location of all external generation is potentially relevant to the estimation of total loopflows, which can have a material impact on which constraints are binding.

adjacent balancing authority area will move around with changes in load and transmission constraints so that no fixed proxy bus can ever provide a representation of marginal generation sources that is ideal over all hours of the year. Instead, the proxy bus location must be selected to provide the best approximation of the location of marginal generation within the adjacent balancing authority area at times when interchange is scheduled and transmission constraints are binding within the modeling balancing authority area.

In achieving this goal of defining a single proxy bus location that provides the best approximation of the location of marginal generation within an adjacent dispatch balancing authority area, a single proxy bus model has a number of elements of flexibility that can be utilized. First, the single proxy bus need not be defined as a single node. While the NYISO has historically defined its proxy bus locations as individual nodes, the single proxy bus used to model interchange with an adjacent balancing authority area could be defined as the weighted average of a number of nodes, rather than a single location. PJM applies such a practice as will be discussed in Section III.

Second, the location of the single proxy bus location is not necessarily fixed. One way to address the issues created by a shifting marginal source of generation would be to employ a proxy bus definition that also shifts around with changes in conditions. Such an approach can be difficult to implement in practice due to a lack of the necessary data regarding external conditions and the lack of predictability associated with a shifting proxy bus definition could potentially adversely impact the scheduling of interchange transactions by market participants. PJM has shown that such an approach can be implemented, having used such a shifting proxy bus to price interchange with the NYISO since 2001, as discussed in Section III below.

Multiple Proxy Bus Systems

Given the approximations inherent in a single proxy bus pricing system for interchange, an important market design issue involving proxy buses in LMP based transmission pricing systems has been the determination of the appropriate number of proxy buses for representing transactions with adjacent balancing authority areas. For example, if a system operator were to define two or more proxy bus locations for market participants to utilize in scheduling transactions over free flowing ties with a single adjacent balancing authority area with whom a single net interchange schedule is established, market participants would be able to choose which proxy bus to utilize for scheduling individual transactions between the balancing authority areas.

This ability of market participants to vary the proxy bus used for dispatch and pricing might at first appear to be useful in addressing the limitations of a single proxy bus system described above but this is not the case if there is a single interchange schedule with the adjacent dispatch region. In such a situation the system operators would dispatch the system without regard to the separate proxy bus schedules, since there would be a single interchange schedule. As a result, the use of multiple proxy buses to schedule a single level of tie line flows would simply provide market participants with a financial incentive to select the proxy bus used for transaction scheduling based on the prices at these proxy buses, without any effect on the actual power flows on the transmission system.

The establishment of multiple proxy buses for a single interchange schedule therefore does nothing to ensure consistency between the designated proxy bus and the actual location at which generation is dispatched up or down to support changes in net interchange. The central feature of a multiple proxy bus system for scheduling a single level of tie line flows that needs to be considered in assessing the operation of such a system is that the dispatch of the exporting balancing authority area is in general completely unaffected by which proxy bus has been designated by market participants as the source of export transactions. The system operator of the exporting region would simply dispatch its system at least cost to support the higher level of net interchange (i.e., to maintain the scheduled level of tie line flows).

The designation of a proxy bus for scheduling purposes by a market participant under such a multiple proxy bus system for scheduling a single level of tie line flows can therefore affect the pricing of interchange power by the modeling balancing authority area but the designation would have no impact on the tie line flows managed by the system operators nor on the location at which generation would be incremented or decremented to support the change in net interchange. If the transmission system in the modeling dispatch area were constrained, the value of the interchange power would depend on the location at which generation were incremented and decremented by the other system operator. Under a multiple proxy bus system for scheduling a single level of tie line flows, market participants would compare the prices associated with each proxy bus and select the proxy bus with the most favorable price.

For example, if market participants had the option of designating either bus D or F in Figure 1 as the source or sink for their transactions and bus D had the higher price, then market participants would designate bus D as the source when exporting power to Balancing Authority Area A and would designate bus F as the sink when buying power from Balancing Authority Area A. If locations D and F were merely used for transaction scheduling purposes, the offsetting transactions would not matter to the control area operators and some transmission owner would be collecting transmission charges on the offsetting transactions. If locations D and F are used to price power or congestion charges within a LMP market, however, such offsetting transactions that yield no net interchange flows could nevertheless require net payments by the system operator (the difference between the price at F paid for imports and the price at D charged for exports). The problem with such dual proxy bus single interchange schedule systems from the standpoint of the system operator and the consumers who will bear the resulting costs is that system operator will pay a premium for a proxy bus designation that has nothing to do with how the power will actually flow and thus has no value to consumers. Such a dual proxy bus system will be beneficial to entities that are able to schedule transactions to exploit the inefficiency of the system without having to bear the associated uplift costs but is not in the interest of consumers.

These problems arising from the use of multiple proxy buses to price a single interchange schedule are not hypothetical but arose for PJM on the NYISO interface during 2000 and early 2001. PJM initially used two distinct proxy buses, NYPP East and NYPP West, to price interchange with New York. The schedules for these proxy buses were completely unrelated to the schedules for the PAR controlled lines between PJM and New York, and aside from the PAR schedules, there was a single net interchange schedule between PJM and New York. While the schedules established for the two New York proxy buses had no operational significance, as predicted above, market participants took advantage of their scheduling flexibility to schedule exports to New York from PJM at the lower-priced proxy bus and schedule imports to PJM from New York at the higher-priced eastern proxy bus, operating a money machine that pumped money out of the PJM market, contributing to revenue inadequacy in real-time congestion rent settlements, until the pricing rules were changed as discussed in Section III.B below.

Multiple Balancing Authority Areas

The problem of money machines that create congestion rent shortfalls and raise uplift costs under multiple proxy bus systems discussed above arises because the multiple proxy buses allow market participants to define contract paths used for pricing do not reflect the actual power flows. The potential for inefficient scheduling incentives and revenue inadequacy under proxy bus systems is not limited to situations in which multiple proxy buses are defined for a single balancing authority area with a single interchange schedule, but can also arise in situations there is a single proxy bus in each balancing authority area but there are multiple adjacent balancing authority areas along a single interface.

If there are several balancing authority areas along a common interface with separate proxy buses and interchange schedules for each balancing authority area, market participants can schedule transmission along a contract path external to the ultimate delivery point for the power so that power sourced in a balancing authority area with a low proxy bus price would be delivered at a proxy bus with a higher proxy bus price. Suppose, for example, that Balancing Authority Area A in Figure 1 was a single balancing authority area, but that buses D, E and F were each separate balancing authority areas establishing separate interchange schedules with Balancing Authority Area A. If the transmission constraint on A-B were binding, the proxy bus price at D would be lower than the proxy bus price at F. Suppose, however, that the difference in proxy bus prices between D and F were larger than the transmission charges required to schedule transmission from D to E to F. Then market participants buying power at D would not schedule the power to flow from proxy bus D into Balancing Authority Area A and sell the power at the Proxy bus D price, but would instead buy transmission service from D to E to F and then sell the power into Balancing Authority Area A at the Proxy Bus F price.

Similarly, if a load in control area F wanted to buy power from Balancing Authority Area A, rather than paying the high price at Proxy Bus F reflecting the need to support those exports with high cost generation at C because of the transmission constraint on the line A-B, the load could buy power at bus D, at the lower price reflecting the more favorable impact on the A-B constraint of power delivered to load at D, and then schedule transmission along the contract path from D to E to F. The load would thereby pay the load bus D price for power actually sinking at bus F and having a less favorable impact on the A-B transmission constraint than power sinking at bus D.

The net effect of two such transactions would be that Balancing Authority Area A would be buying power at the high price at F and selling power at the low price at D, but rather than getting the favorable powerflows over the A-B constraint that would be associated with incrementing generation at F and decrementing generation at D, there would be an increase in generation at D and a decrease in generation at F, which would increase flows over line A-B, requiring the balancing authority area to back down low-cost generation at A and dispatch up higher-cost generation at C.

This potential for inefficient scheduling incentives with single proxy buses but multiple balancing authority areas is also not hypothetical as it basically describes the situation that arose for PJM in scheduling transactions with AEP and VACAR during 2002, as discussed below in Section III.B below.

III. EVOLUTION OF EASTERN PROXY BUS PRICING SYSTEMS

A. NYISO Proxy Buses

The NYISO initially had four proxy buses, one each for modeling interchange with ISO-NE, Ontario, PJM and Hydro Quebec.[12] Since NYISO start-up, four additional proxy buses have been added for the purpose of modeling the impact of power scheduled to flow over controllable lines (DC lines or PAR controlled lines) or in one case in order to separately model wheel-through transactions that are subject to special coordination rules between PJM and NYISO. These additional proxy buses are the proxy bus for the Cross Sound Cable from New England (June 7, 2005),[13] the 1385 line with New England (June 27, 2007), the Neptune line from PJM (July 1, 2007), and the Hydro Quebec wheel through proxy bus (July 1, 2007).[14]

New England Interface

The NYISO currently has three proxy buses for the purpose of modeling interchange with ISO-New England. Two proxy buses are used to model schedules over controllable lines between ISO-New England and NYISO (the Cross Sound Cable and the 1385 line). The third proxy bus, Sandy Pond, is used to model all transactions with ISO-NE that are not scheduled to flow over one of the controllable lines. Absent changes in schedules on the controllable lines, the NYISO models an increase in imports from ISO-NE as being supplied by increased generation at Sandy Pond, while increased exports from NYISO to ISO-NE are modeled as backing down generation at Sandy Pond.[15]

---

12 See NYISO Technical Bulletin 37, May 19, 2000.

13 The Cross Sound Cable was initially energized following the black out in August 2003. The 2005 date is the point in time at which a separate proxy bus was implemented which allowed entities other than LIPA to schedule transactions on the line.

14 A proxy bus was scheduled to be activated for scheduling interchange on the Cedars-Dennison controllable line between Hydro Quebec and the NYISO on August 1, 2007; however, activation has been delayed until various regulatory issues relating to DOE regulations are resolved. Rana Mukerji, "Update on Northeast Seams Issues," NYISO Business Issues Committee Meeting, December 5, 2007, p. 8.

15 See NYISO Technical Bulletin 37. Sandy Pond is the location of the ISO-NE end of a DC interconnection between Hydro Quebec and NEPOOL.

In addition to these flows over the free-flowing ties, transactions may also be scheduled between ISO-NE and Long Island on the Cross Sound Cable which is a DC line.[16] Power scheduled to flow over the Cross Sound Cable is modeled distinct from other net interchange with ISO-New England and as radially connected to Long Island (except for the contingency analysis of the Cross Sound Cable) because the amount of power flowing over this cable is determined by the cable operator, not by changes in generation in ISO-New England or in New York. The congestion impacts on New York are determined by the Cross Sound Cable schedule, rather than the location of the generation raised or lowered by ISO-NE to support the schedule.[17] Conversely, the congestion impacts on New England do not depend on the location at which the NYISO raises or lowers generation in response to changes in Cross Sound Cable schedules. Because the Cross Sound Cable is a merchant line with all capacity contracted for on a long-term basis by LIPA there are a number of special rules regarding the scheduling and pricing of power on the Cross Sound Cable that are not relevant to this paper.[18]

Since June 27, 2007 transactions between ISO-NE and NYISO may also be scheduled to flow on the 1385 line which is a phase angle regulator (PAR) controlled line between ISO-NE and Long Island.[19] Power scheduled to flow over the 1385 line is modeled distinctly from other net interchange between New York and ISO-NE and as radial to Long Island because the phase angle regulators can be used to ensure that the physical pre-contingency flows on the line correspond to the schedule.[20] Once again, the congestion impact of changes in interchange between NYISO and ISO-NE will differ depending on whether the power is scheduled to flow over the 1385 line or the remainder of the AC interface.[21]

All power scheduled to flow between ISO-New England and the NYISO is modeled as flowing over either one of the controllable lines or the lines making up the NYISO-ISO-New England interface. Because the Hydro Quebec control area is connected to ISO-NE and NYISO with DC lines, there are no loopflows through Hydro Quebec associated with the schedules between NYISO and ISO-New England, all scheduled net interchange flows over the lines on the NYISO ISO-New England interface.

---

16 See NYISO Technical Bulletin 141, revised June 17, 2007, "Scheduling Transactions at the Proxy Generator Bus Associated with the Cross-Sound Scheduled Line."

17 This is the case as long as the outage of the Cross Sound Cable is not a binding contingency. If the Cross Sound Cable were to trip out of service, the power scheduled to flow over the cable would instead flow over the free-flowing ties between ISO-NE and New York. See "Controllable Lines" Concept of Operation, New York Independent System Operator, January 8, 2003. The transfer capability of the Cross Sound Cable is small relative to other transmission contingencies on the NYISO-ISO New England interface so this outage contingency is not a practical consideration.

18 See NYISO Technical Bulletin 141 and the NYISO Filing letter in docket ER05-727-000 March 25, 2005

19 See NYISO Technical Bulletin 161, June 13, 2007, "Scheduling Transactions at the Proxy Generator Bus Associated with the Northport-Norwalk Scheduled Line."

20 Changes in PAR settings can be necessary to hold line flows to the scheduled level and PARs can exhaust their ability to hold pre-contingency flows to the schedule.

21 As in the case of the Cross Sound Cable, this is true as long as the outage of the 1385 line is not the binding contingency. Since the scheduling limit on the 1385 line was initially set at 100MW (see NYISO Filing letter in ER07-806-000 April 27, 2007), the outage of the 1385 line would be far smaller than other contingencies on the NYISO-ISO-NE interface.

It is important to recognize that the location at which the NYISO models the New England proxy bus for the purpose of analyzing congestion impacts is not necessarily the same as the point of delivery or interconnection. While the proxy bus location and the point of delivery are the same for the controllable lines (the Cross Sound Cable and the 1385 line),[22] they are quite different in the case of the free-flowing tie lines between New York and New England. While the NYISO models internal congestion impacts with a proxy bus located at Sand Pond, internal to ISO-New England,[23] the actual point of delivery for power flowing over the free-flowing ties is the point at which the transmission lines cross the New York-New England border.[24]

PJM Interface

The NYISO currently has two proxy buses for the purpose of modeling interchange with PJM. One proxy bus is used to model schedules over the Neptune line between PJM and Long Island. The other PJM proxy bus is Keystone and it is used to model all transactions with PJM that are not scheduled to flow over the Neptune line.[25] If the schedules on Neptune do not change, the NYISO will analyze the congestion impacts of a change in net interchange between PJM and NYISO through a change in generation at Keystone.[26]

Thus, when an additional MWh of imports from PJM is scheduled in the NYISO day-ahead market, the NYISO's security-constrained unit commitment software (SCUC) models that import as if it were supported by a 1 MWh increase in net generation at Keystone, and the day-ahead LBMP price for that import is the price at Keystone. Underlying this modeling decision was the NYISO's expectation in 1999 that PJM's least cost dispatch would usually entail raising generation on a unit located somewhere in Western Pennsylvania, not in New Jersey. The selection of the NYISO PJM proxy bus was therefore intended to roughly reflect the region of PJM in which generation would usually be raised to support an export schedule to New York or decreased in response to increased imports from New York.

Until June 6, 2007, the NYISO day-ahead, hour-ahead and real-time dispatch software models treated phase angle regulator (PAR) schedules on the tie lines between NYISO and PJM as fixed; that is, they assumed that the PARs would be moved to hold flows to the schedule and thus that the schedule on the PAR controlled line was independent of the overall level of net interchange.

---

22 "Coordination Agreement between ISO New England Inc. and New York Independent System Operator," January 1, 2006, p. 3 and Schedule A, pp. 24-25. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/NYISO_ISONE_Crdntn_Agrmnt_1_1_06.pdf

23 NYISO Technical Bulletin 37.

24 "Coordination Agreement between ISO New England Inc. and New York Independent System Operator," January 1, 2006, p. 3 and Schedule A, pp. 24-25. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/NYISO_ISONE_Crdntn_Agrmnt_1_1_06.pdf

25 Keystone is the location of a large coal-fired generator in Western Pennsylvania.

26 There are also a number of PAR controlled lines between PJM and NYISO for which separate proxy buses have not been established because the impact of the PAR controlled flows is accounted for in other ways. First, the ABC lines into New York City and the JK lines into New Jersey are PAR controlled and used to implement a wheeling agreement between Con Ed and PSEG. Second, the Ramapo PAR is used to control flows between NYISO and PJM.

Since most of the tie lines between NYISO and PJM in eastern PJM are PAR controlled, the assumption of fixed schedules on the PAR controlled lines meant that most imports from PJM were modeled as flowing into the NYISO on western transmission lines, lowering the value of these imports and also meant that the pattern of inter-regional flows did not vary much in NYISO models with changes in the location of the incremented or decremented generation in PJM, because most of the flows were determined by the assumed or actual PAR schedules.

A change in modeling assumption was introduced during 2007 which specified the fraction of NYISO-PJM interchange that would be modeled as flowing over the JK, ABC, and 5018 PAR controlled lines.[27] This change in modeling tended to raise the value of power imported from PJM when transmission constraints are binding in eastern New York. The scheduling of power over the ABC and JK lines is also governed by the PSEG-Con Edison wheeling agreement and the recently devised procedures to better implement that agreement.[28]

Back in 2000 and 2001 some market participants suggested that the NYISO should establish a separate Eastern PJM proxy bus and model import supply at the Eastern PJM proxy as having an impact on New York transmission constraints of a generator being raised in Eastern PJM. Had the NYISO established dual PJM proxy buses, market participants would undoubtedly have scheduled imports into New York as sinking at the Eastern PJM proxy bus (so they would be paid a high price for the imports) and exports to PJM as sourced from the Western PJM proxy bus (So they would be charged a low price for the exports.) This ability to choose the proxy bus price would have raised the proxy price paid by the NYISO for imports that were scheduled for delivery at the NYISO's Eastern PJM proxy bus. This higher payment would not have changed the location of the generation raised by PJM to support exports, however, NYISO market participants would have paid the higher Eastern PJM proxy price for generation flows that, if the NYISO's expectations regarding the PJM dispatch are correct, would actually have come from Western Pennsylvania and would have required backing down cheap Western New York generation, rather than displacing expensive Eastern New York generation. The imports scheduled from this proxy bus would have raised, not lowered, the cost of meeting load in New York.

Since July 1, 2007 transactions between PJM and NYISO may be scheduled on the Neptune line which sources in New Jersey and sinks on Long Island.[29] Because the Neptune line is a DC cable, the flows on this line can be controlled separately from the overall level of interchange on the PJM interface and the flows on the line will vary with schedules. The flows on the Neptune line are therefore modeled as radially connected to Long Island, except for the purpose of modeling the outage of Neptune itself.

---

[27] NYISO Technical Bulletin 152, revised May 8, 2007, "PJM Proxy Bus Pricing and Scheduling." Michael Martin (NYISO), "PJM Proxy Bus Pricing Enhancements – Post-Implementation Review," MIWG October 17, 2007, located at http://www.nyiso.com/public/committees/documents.jsp?com=bic_miwg&directory=2007-10-17&cols=5&rows=5&start=1&maxDisplay=999.

[28] See PJM Market Monitoring Unit, "2005 State of the Market Report," pp. 199-203; "2006 State of the Market Report," pp. 189-190, located at http://www.pjm.com/markets/market-monitor/som-reports.html. "Joint Compliance Filing of NYISO, PJM and PSEG," Docket EL-02-23-00, February 18, 2005.

[29] See NYISO Technical Bulletin 162, July 10, 2007, "Scheduling Transactions at the Proxy Generator Bus Associated with the Neptune Scheduled Line."

The NYISO models all scheduled net interchange between PJM and the NYISO as flowing over either the Neptune line or one of the AC lines connecting PJM and the NYISO. Thus, for the purpose of modeling congestion impacts on the NYISO transmission system, the NYISO does not take account of the loopflows around Lake Erie and through Ontario associated with PJM to NYISO schedules. This assumption is inaccurate but it has so far provided a workable approximation for the NYISO, probably because this assumption is not material for calculating flows on constraints in eastern New York and transmission constraints in western New York rarely bind. These assumptions would be material for calculating the flows over lines between New York and PJM, and between New York and Ontario. Those interfaces are scheduled based on scheduling limits in part because allowance must be made for substantial loop flows unrelated to NYISO transactions.

As in the case of ISO New England, the location at which the NYISO models the PJM proxy bus for the purpose of analyzing congestion impact is distinct from the point of delivery or interconnection in the case of the free-flowing ties. While the NYISO model's internal congestion impacts with a PJM proxy bus located at the Keystone generation plant, the actual points of delivery for power flowing over the free-flowing ties are different.[30] While two of the common meter points are at Homer City, the proxy bus is not located radially at the end of the Homer City transmission lines but at the Keystone generator.

Hydro Quebec Interface

The NYISO currently uses two proxy buses to represent transactions scheduled with Hydro Quebec. The first proxy bus is Chateauguay, which is the location of the main interconnection with Hydro Quebec. The second proxy bus is an additional proxy at Chateauguay that is used to model wheel through transactions with Hydro Quebec.[31] Both proxy buses are modeled as located at the same place electrically, having exactly the same shift factors on all constraints. The second proxy bus is used only for the scheduling of wheeling transactions in excess of the 1,200 MW NYISO first contingency. The Hydro Quebec-NYISO interconnection differs from the Ontario, PJM and NEPOOL interconnections in that there is no AC interconnection between the transmission system serving Hydro Quebec and the NYISO.

---

[30] "Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, LLC," May 2007, p. 4 and Schedule A, p. 32. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf

[31] See NYISO Technical Bulletins 37 and 158 revised July 23, 2007; NYISO filing in docket ER07-669-000 March 28, 2007. Net imports to the NYISO from Hydro Quebec are normally limited to 1200MW which is the largest contingency for the NYISO control area. If imports from Hydro Quebec at Chateauguay exceed 1200MW, the loss of the connection with Hydro Quebec would become the largest contingency, changing the reserve requirements for the NYISO. Procedures have been worked out between Hydro Quebec, NYISO and PJM, however, that permit the NYISO to schedule up to 1200MW of net imports from Hydro Quebec plus additional wheel through transactions to PJM, whereby in the event of the loss of the Hydro Quebec connection, the wheelouts to PJM will also be cut, so that the NYISO's single largest contingency remains 1200 MW. See NYISO Technical Bulletin 158. The additional proxy bus was added at Chateauguay to enable the NYISO to better implement this treatment of wheel through transactions.

Ontario

The final NYISO proxy bus is Bruce, the NYISO proxy bus for transactions with the Ontario IESO.[32] Symmetric with the NYISO's modeling of PJM, the NYISO models effectively assume that Ontario is radial to the NYISO with no loop through Michigan.

The NYISO is potentially exposed to inter-balancing authority area contract path scheduling impacts for power originating in MAIN which could schedule a contract path to New York either through Ontario or through PJM. Since generation at the PJM proxy bus has a more favorable impact on Central East than generation at Bruce in Ontario, it is likely that most entities scheduling imports into NYISO from MAIN originally chose a contract path coming in through PJM, rather than through Ontario, although the power actually flowed through both Ontario and PJM. This type of contract path scheduling has to date not been an issue for the NYISO. This may in part have been because both the PJM and Ontario proxy buses are electrically well to the west of Central East, however the differences between the shift factors of the PJM and Ontario proxy buses on Central East are not insignificant.

Historically, it may have been the case that most scheduling of MAIN generation into the NYISO was along a contract path through PJM, but that the impact of such MAIN imports was limited by the cost of scheduling contract path transmission from MAIN into NY under pancaked tariffs in the Midwest, so that few such imports were scheduled. It may therefore be the case that with the reduction in pancaked tariffs in the Midwest following the implementation of the MISO energy markets, the NYISO may over time see an increase in generation schedules that have contract paths through PJM, but that if accepted by NYISO, will cause incremental generation to be dispatched in MAIN or even MAPP.

Such a change in generation patterns could make it desirable for the NYISO to move its PJM proxy bus further west, potentially even into ECAR, to reflect the actual location of incremental generation and bring modeled flows on Central East more in accord with actual flows. On the other hand, the expected 2008 operation of PARs controlling Ontario to Michigan power flows, may not only obviate the problem of contract path scheduling into the NYISO but may also make the impact of other loopflows on Central East more predictable.

As in the case of ISO-NE and PJM, the location of the NYISO's proxy bus is distinct from the points of interconnection at which power is delivered from one transmission system to the other. The points of interconnection are on the international border between Ontario and New York.[33]

---

[32] NYISO Technical Bulletin 37. Bruce is the site of substantial nuclear generation.

[33] See "Interconnection Agreement Between Independent Electricity Market Operator and the New York Independent System Operator, Inc." May 1, 2002, pp. 4, 5 and Schedule A, p. 29. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/imonyiso.pdf

B. PJM Proxy Buses

PJM's proxy bus pricing system has undergone a number of changes since the implementation of LMP in 1998, reflecting the construction of a new DC line (Neptune), the westward expansion of PJM, and changes in proxy bus design. The focus of this paper is on the changes in proxy bus design, but the other changes will be briefly summarized for clarity. First, the construction of the Neptune line (a controllable line between PJM and New York) that became operational on July 1, 2007, resulted in the creation of an additional proxy bus for the scheduling of transactions on this line.

Second, the expansion of PJM has led to changes over time in the identity of proxy buses, also referred to as interface pricing points, as the identity of adjacent control areas has changed. PJM initially had two NYISO proxy buses, a First Energy proxy bus, an APS proxy bus and a VACAR proxy bus. When APS joined PJM in 2002, the APS proxy bus was eliminated, and Duquesne and AEP Proxy buses were added.

With the integration of Com Ed into PJM on May 1, 2004, the number of external pricing points rose from 6 to 23. The integration of AEP and Dayton on October 1, 2004 enabled PJM to eliminate many of these pricing points and the number of external pricing points fell to 9.[34] These were the Northwest (Wisconsin-Wisconsin Electric Power, Alliant East, Alliant West, and MEC); OVEC (Ohio Valley Electric Corporation-internal to PJM),[35] DLCO (Duquesne balancing authority area internal to PJM); NYISO; Ontario; MICHFE (Michigan Electric Coordinated System, First Energy); Southwest (Central Illinois Light, Indianapolis Power and Light, Ameren, Cinergy, East Kentucky Power Cooperative, LG&E and TVA) and Southeast (Carolina Power and Light, Duke Power, and Dominion Virginia Power). It is noteworthy that PJM has frequently used a single proxy bus for a balancing authority area having multiple points of interconnection with PJM and that in a number of instances PJM used a single pricing point for schedules with multiple balancing authority areas. Thus, while transactions with each external balancing authority area using the Southeast pricing point would have a contract path through that balancing authority area and be checked out with that balancing authority area, all of them would be settled at the same pricing point.

With the integration of Duquesne into PJM on January 1, 2005 the Duquesne pricing point was eliminated. On April 1, 2005 the MISO pricing point was created to reflect the creation of the MISO, and on May 1, 2005 Dominion was integrated into PJM and no longer part of the Southwest Pricing Point.[36]

---

[34] PJM Market Monitoring Unit, "2004 State of the Market Report," pp. 118-119, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

[35] Since the shutdown of the DOE facilities in OVEC in April 2003, the OVEC control area has contained more than 2,000 MW of generation and only token load. OVEC has a number of interconnection points with adjacent transmission systems but is represented as a single proxy bus by PJM for pricing purposes. PJM provides reliability coordination services for OVEC under an agreement that does not appear to be public. PJM Manual 37 Reliability Coordination, pp. 20-24, May 15, 2007.

[36] PJM Market Monitoring Unit, "2005 State of the Market Report," pp. 170, 181, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

The third types of changes in PJM proxy bus design are those that are most relevant to illustrating and understanding the issues involving the appropriate number of proxy buses. These changes were not driven the construction of new lines or the expansion of PJM but were made in response to the scheduling practices of PJM market participants. There were seven changes of this type.

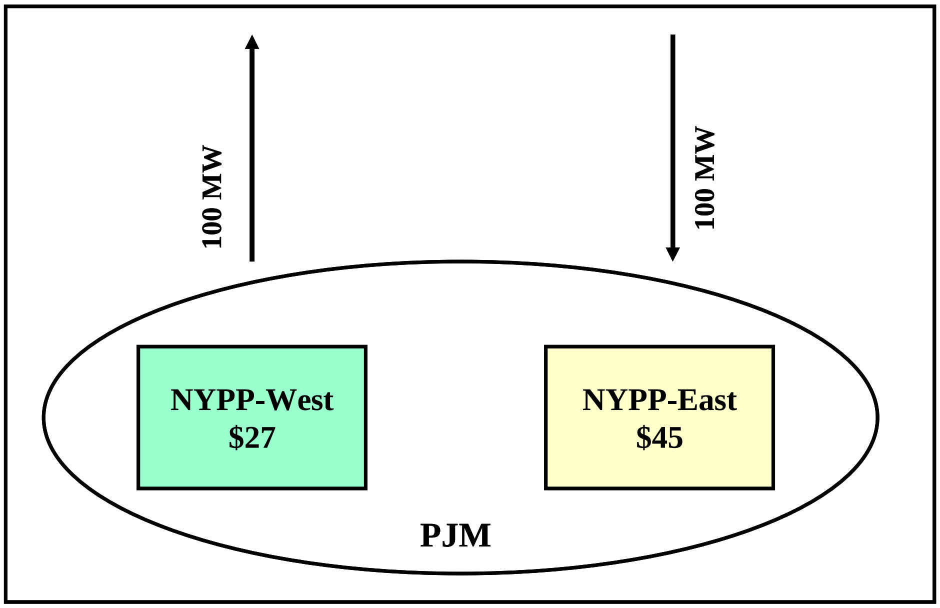
The first change involved the pricing of interchange with the NYISO. Until early 2001, PJM priced imports from and exports to New York based on prices determined for both a NYPP East and a NYPP West proxy bus.[37] Thus, PJM permitted market participants to designate either NYPP east or NYPP west as the source or sink of their transaction as shown in Figure 3. Moreover, the proxy buses were modeled as being at electrically distinct locations so that the price at the NYPP west proxy bus reflected the value of power delivered into or exported from western PJM, while the price at the NYPP east proxy bus reflected the value of power delivered into or exported from eastern PJM. When PJM was constrained from West to east, imports from the NYPP east bus would appear more valuable than imports from the NYPP west bus, and conversely, exports to the NYPP east bus would appear more expensive.

---

[37] It should be noted that neither of these locations was a point at which PJM and the NYISO metered net interchange (i.e., neither was a physical delivery point. For example, although NYSEG owns transmission lines extending down into Pennsylvania at Homer City (NYSEG used to own a share of the Homer City plant), PJM did not model imports from western New York as being delivered at the Homer City metering point, nor did PJM model its exports to western New York as sinking at the Homer City metering point.

Thus, if PJM was constrained from west to east, the proxy prices might differ as shown in Figure 3, with a PJM price at the NYPP east bus of $45/MWh, while the price at the NYPP west bus was $27/MWh. The fundamental problem with this dual proxy bus system for NYISO interchange was that since the NYISO was a single balancing authority area, PJM and the NYISO set a single interchange schedule and the designation of the source or sink of some transactions as being either NYPP east or west had no meaning for the dispatch of generation in either PJM or New York.

Figure 3
1999-2001 PJM-NYISO Proxy Bus Pricing



A fundamental problem with this dual proxy bus design for interchange schedules with the NYISO control area was that PJM and NYISO agreed upon a single interchange schedule. The fact that an export to PJM was designated to come from the NYPP East proxy bus had no meaning for the NYISO dispatch. Even if the NYISO had implemented a similar structure with a PJM east and PJM west proxy bus, those distinctions would have had no meaning for New York and PJM because they agreed upon a single interchange schedule and adjusted generation to support that single schedule. As a result of this dual proxy bus structure, in 2000 a market participant could schedule a 100MW export to NYISO from the PJM NYPP west bus and pay $27/MWh for this power and simultaneously schedule a 100MW import to PJM at the PJM NYPP east bus and be paid $45/MWh for the power, yet for the purpose of the PJM and NYISO check out and dispatch, nothing would happen. PJM would simply pay out a net of $1800 for transactions that netted to zero.

By late 2000 and early 2001, PJM and NYISO market participants had figured out that it was profitable to designate NYPP west as the sink for all exports, resulting in a lower price paid to PJM, and to designate NYPP east as the source for all imports, resulting in a higher price paid by PJM. PJM for example, calculated that over the period December 2000- February 2001, 97% of the transactions scheduled at the NYPP west proxy bus were exports from PJM and only 3% were imports, while 87% of the transactions scheduled at the NYPP east proxy bus were imports and only 13% were exports.[38] During the same hour, therefore, PJM was potentially selling power at a low price for exports sinking at NYPP west and buying power at a high price for imports sourced at NYPP east, yet there might be no net interchange with the NYISO.

Some market participants suggested that PJM's difficulties would somehow be addressed if the NYISO were to establish separate proxy buses for eastern and western PJM. Had the NYISO set up such a PJM East proxy bus, market participants could have exploited the price differentials between the NYISO Eastern and Western PJM proxy buses in the same way they exploited the dual PJM buses for the NYISO, with schedules that would have imposed uplift costs on New York customers without delivering any energy. It was this kind of inefficient scheduling by PJM market participants that caused the PJM ISO to implement a single proxy bus pricing system on the NYISO Interface in early 2001.[39]

In early 2001 PJM recognized that the dual proxy bus system for an interface with a single interchange schedule was exposing PJM consumers to significant real-time congestion rent shortfalls (and thus uplift costs) and the dual proxy bus was replaced on April 1, 2001 with a single proxy bus for the NYISO interface, consistent with the single interchange schedule agreed upon by PJM and the NYISO. Under this system, the PJM proxy bus for NYISO was initially based on an 80-20 weighting of generation located at Roseton and Dunkirk. Thus, an incremental MW of exports from PJM to NYISO was modeled as backing down .8 MW of generation at Roseton and .2 MW of generation at Dunkirk.[40]

---

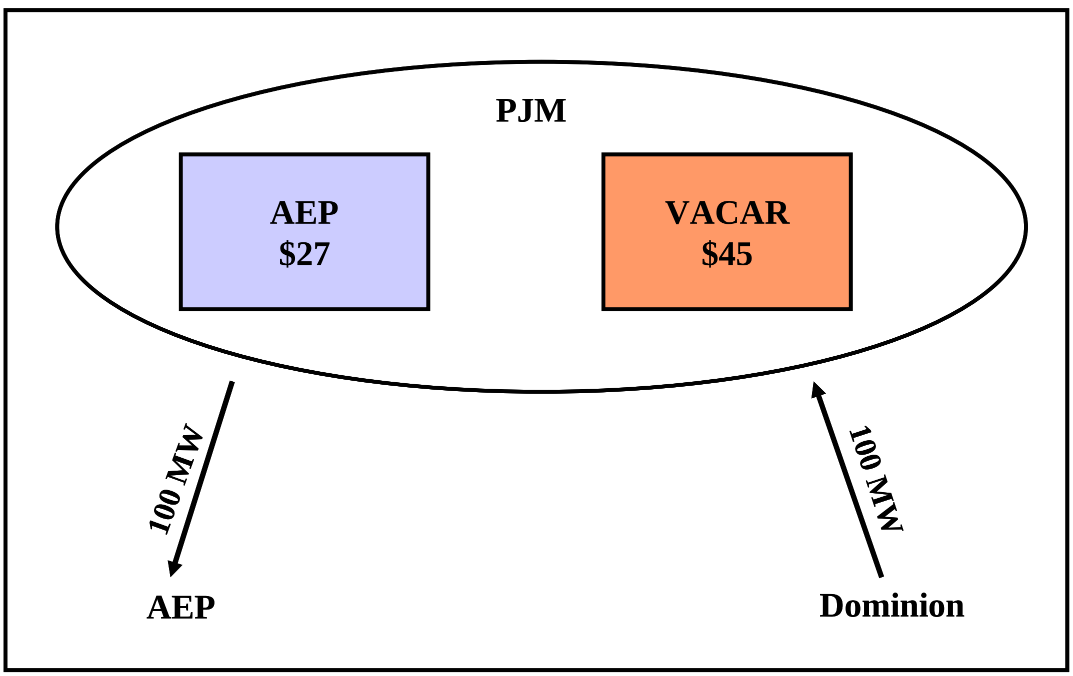
38 Andy Ott, "Congestion Charges and Loopflow," p. 5.

39 See Andrew L. Ott, "Congestion Charges and Loop Flow."

40 The proxy bus still did not coincide with any of the metering points for interchange between PJM and New York. See pjm.com/markets/energy_market/downloads/2008053_aggregate_definitions.xls

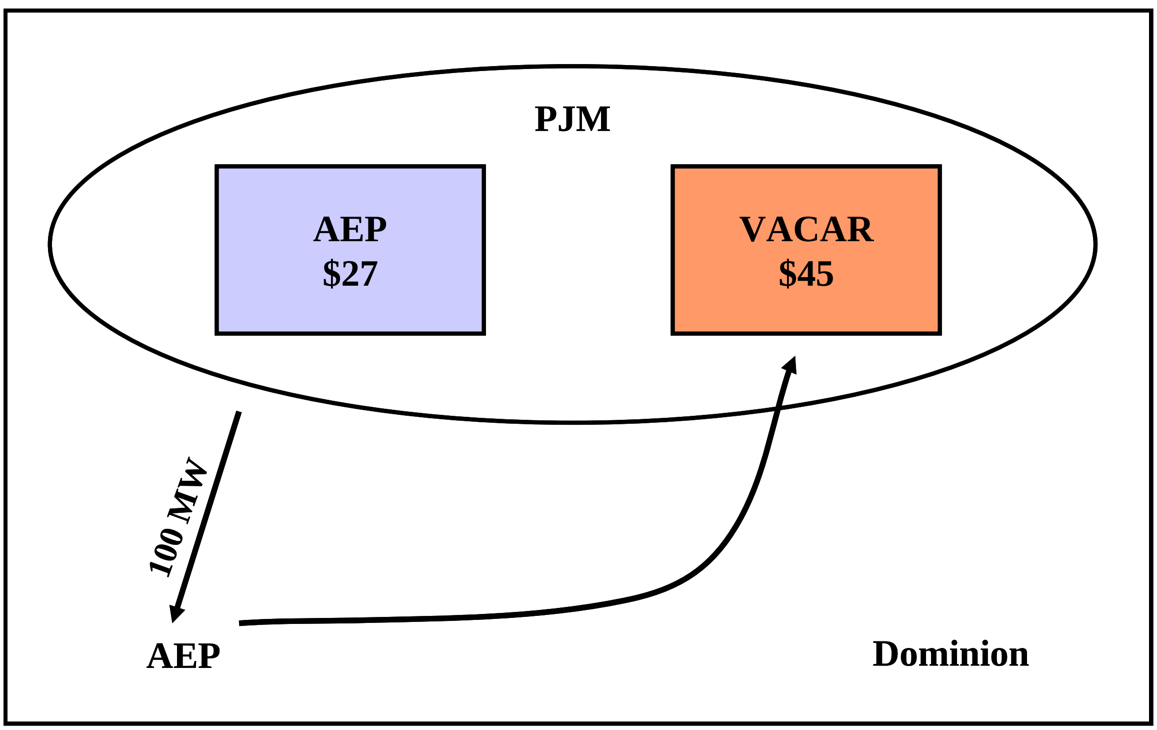
The next change in PJM proxy bus design arose not to correct problems arising from having multiple proxy buses for scheduling transactions with a single balancing authority area but from the more complex problem discussed in Section II of having individual proxy buses for individual balancing authority areas along an interface with multiple balancing authority areas. After APS joined PJM on April 1, 2002, PJM had separate proxy buses for VACAR and AEP, along its southern and western edge. Dominion (VACAR) and AEP were separate balancing authority areas so the separate proxy bus schedules had operational significance. If 100 MW imports were scheduled and cleared checkout between Dominion and PJM, then Dominion would raise its generation by 100 MW relative to its load, while PJM would lower its generation by 100 MW relative to its load, resulting in a net flow of power between the two balancing authority areas (along all parallel paths). Similarly if 100 MW of exports were scheduled and cleared check out from PJM to AEP, then PJM would raise generation by 100 MW and AEP would lower generation by 100 MW relative to its load, as illustrated in Figure 4.

Figure 4
PJM Interchange Scheduling with AEP and Dominion



The net effect of the two transactions would in effect be to raise generation in Dominion and lower generation in AEP which would produce favorable (east to west) flows through PJM when west to east constraints were binding in PJM. The difference between the $45/MWh price paid for imports from Dominion and the $27/MWh price at which power was sold into AEP would reflect the value to PJM of the flows created by raising generation in VACAR and lowering it in AEP. The problem that arose was that interchange schedules sourced in Dominion and sinking in PJM or sourced in PJM and sinking in AEP did not necessarily cause generation to rise in Dominion and fall in AEP. Suppose that the transaction sinking into PJM from Dominion was in fact sourced in AEP along a contract path from AEP into Dominion and then into PJM as illustrated in Figure 5. In this case, PJM has paid $18/MWh for transactions that had no net impact on PJM net interchange or congestion. These kind of transactions were profitable any time the price spread between PJM's AEP and VACAR bus rose above the cost of purchasing transmission along the contract path from AEP into VACAR and then into PJM.

Figure 5
Contract Path Scheduling into PJM via Dominion



In 2002 PJM found, based on e-tags, that many transactions being scheduled as sinking at the PJM VACAR interface were actually sourced in Main or ECAR and being scheduled on a contract path for delivery into PJM from VACAR. Thus, market participants were scheduling transactions along a contract path Main –VACAR – PJM, rather than along the contract path MAIN-PJM, presumably because the transmission charges to schedule along the contract path into VACAR were less than the difference in the PJM LMP price between the AEP and VACAR proxy buses. This contract path delivery location entitled the transactions to be paid the VACAR proxy bus price, but the actual electrical impact of the transactions on PJM constraints was much more like power delivered on the AEP interface.[41]

In response to this problem PJM provided, effective July 19, 2002, that transactions scheduled to sink at the VACAR proxy bus but having an e-tag indicating an ECAR or MAIN source would be paid the price for the AEP bus, rather than the VACAR proxy bus.[42]

In terms of the example in Figure 1 above, this would be equivalent to checking for tags on transactions coming in from bus F and paying the D Proxy bus price any time the tag showed an origin at D for transactions scheduled to sink at bus F. As suggested in the discussion in Section II, the limitation of PJM's initial approach was that traders could simply break their transaction into two parts, buying in balancing authority area D and selling in balancing authority area F system, then buying in balancing authority area F and scheduling a transaction into Control Area A at the F proxy bus. In terms of the actual change in generation, this would be identical to a single transaction sourced in control area A. PJM market participants may have responded in just this manner to the initial PJM rules, leading to the increased divergence between actual and modeled flows that caused PJM ultimately to combine the AEP and VACAR proxy buses as discussed below.[43]

Third, PJM shifted in January 2003 to calculating proxy bus prices for the NYISO interface using weights based on the proportion of power flowing over two tie lines on that interface. Thus, rather than the NYISO interface being priced based on the fixed 80% 20% weights established in 2001, the weights varied based on the proportion of power flowing over the two tie lines between NYISO and PJM in real-time.[44]

Fourth, effective March 1, 2003 PJM combined the AEP and VACAR proxy buses and assigned transactions sourced in a particular balancing authority area to a pricing point without regard to the contract path.[45] The problem addressed by this change was again that arising from multiple proxy buses on a common interface. The 2002 changes addressed the problem of individual transaction scheduled along a contract path from AEP into VACAR and then into PJM by using

---

[41] PJM Market Monitoring Unit, "Report to the Federal Energy Regulatory Commission, Interface Pricing Policy," August 12, 2002, located at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/200208-report-ferc1.pdf.

[42] PJM Market Monitoring Unit, email to Energy Market Committee, August 1, 2002; "Report to the Federal Energy Regulatory Commission, Interface Pricing Policy," August 12, 2002 and email to Energy Market Committee, August 27, 2002. PJM Market Monitoring Unit, 2002 State of the Market Report, pp. 56-60, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

[43] PJM Market Monitoring Unit, "Report, Interface Pricing Policy, February 28, 2003, located at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20030301-interface-pricing.pdf. PJM, "PJM Interface Pricing Changes," no date.

[44] PJM Market Monitoring Unit, "2003 State of the Market Report," p. 106, located at http://www.pjm.com/markets/market-monitor/som-reports.html. PJM, "Dynamic Interfaces," January 22, 2003. "PJM Interface Price Definition Methodology."

[45] PJM Market Monitoring Unit, "2003 State of the Market Report," pp. 95-96, 101-102; PJM Market Monitoring Unit, email to Energy Market Committee, January 9, 2003 "Report on Interface Pricing Policy," February 28, 2003.

etags to identify transactions sourcing outside VACAR and to determine the pricing for such transactions. Etags do not reveal where generation was actually incremented or decremented, however. To understand this, suppose that instead of a single transaction along the contract path from AEP into VACAR into PJM as portrayed in Figure 5 there were two transactions with distinct tags, one transaction from AEP sold into VACAR and another transaction sourced from VACAR and sold into PJM. The etag source of the transaction that is checked out with PJM would be VACAR, yet the net effect of the two transactions is that generation is raised in AEP, not in VACAR. Given its inability, even using etags, to distinguish interchange schedules that would produce an increase in generation within VACAR from those that would produce an increase in generation in AEP, PJM combined the interfaces for pricing purposes. PJM continued to separately conduct its check out with each control area, but for the purpose of pricing the impact of transactions on its internal transmission constraints, PJM switched to using a single pricing point, eliminating the inefficient scheduling incentives of market participants that had arisen from the dual pricing points.

Fifth, on August 1, 2003 PJM established a separate proxy bus for transactions with e-tag sources in Ontario, reflecting the differential impact of these transactions on PJM, compared to other transactions with a contract path over the NYISO interface.[46] The problem addressed by this change is that while a direct contract path schedule from the Ontario IESO balancing authority area through the NYISO into PJM might provide the highest netback to Ontario sellers, if generation were raised in Ontario, part of the power would flow around through Michigan, impacting western PJM constraints. Using the Etag to distinguish transactions sourcing in IESO from those sourcing in NYISO is similar to the approach initially used with AEP and VACAR and may ultimately be rendered ineffective by entities scheduling separate transactions sourced in Ontario and sinking in the NYISO and sourced in NYISO and sinking in PJM.

Sixth, on October 1, 2006, PJM’s southeast and southwest interface pricing points were consolidated and separate proxy buses established for the pricing of imports and exports. The origin of this problem was in the westward expansion of PJM when separate proxy buses were established for the Southwestern balancing authority areas (Cinergy, TVA, etc.) and the Southeastern balancing authority areas (Duke, etc.). While these new proxy buses spanned groups of balancing authority areas, transactions scheduled from these regions turned out not to have distinguishable impacts on PJM transmission constraints, again because power scheduled to flow from the Southeast region into PJM, could in reality be supported by generation increases in the Southwestern region, scheduled along a contract path into the Southeast region and then into PJM. When PJM was constrained from west to east it and the Southeastern proxy bus price rose relative to the value of power from the Southwestern proxy bus, PJM found that import transactions were sourced with contract paths from the Southeast, but the actual powerflows over its lines were from the Southwest. Moreover, this was the case even though the application of the Southeast proxy bus price was based on the source balancing authority area on the transaction etag. As in 2002, etags were ineffective in identifying the actual location at which generation would be raised.

46 PJM Market Monitoring Unit, “2003 State of the Market Report,” p. 102.

Another feature of this change in proxy bus definition was that PJM used different bus weights to price imports and exports at the new proxy bus. This likely reflected a PJM judgment that during the conditions in which PJM would likely be exporting to this region, generation in the region of the export proxy bus would be on the margin, while during the conditions in which PJM would likely be importing from this region, generation in the region of the import proxy bus would likely be on the margin.[47]

Finally, during early 2007 PJM entered into Interface Pricing Arrangements with Duke Energy (January 5, 2007),[48] Progress Energy Carolinas (February 13, 2007)[49] and the North Carolina Municipal Power Agency Number 1 (March 19, 2007),[50] under which Duke, Progress and the North Carolina Municipal Power Agency can buy and sell power to PJM at prices calculated for generator nodes on their system (rather than the South IMP or South EXP proxy bus price).[51]

These agreements have a number of provisions limiting the circumstances in which the DECGen, PECGen, and NCMPAGen proxy prices will be applicable but the essence of these agreements is that these proxy bid prices will only be applicable if these entities are not purchasing power outside their balancing authority area. The point of these restrictions is that if these entities are not purchasing power from outside their balancing authority area, then any increase in exports to PJM must be supported by an increase in generation located within their balancing authority area. Conversely, any decrease in imports from PJM must be supported by a decrease in generation within their balancing authority area.

The DECGen, PECGen and NCMGen prices are not applicable when the relevant entities are purchasing power located outside their balancing authority area because in those circumstances there is no assurance that generation will increase within the Duke, Progress or North Carolina Municipal Power Authority balancing authority areas to support these exports to PJM.

The DECGen, PECGen and NCMGen proxy bus prices are apparently applicable when the relevant entities are selling power to buyers other than PJM located outside of their balancing authority area. If sales to PJM were accompanied by a reduction in sales to other balancing

---

[47] Stan Williams, "Uncompensated Parallel Flow (Loopflow) Update," August 8, 2006. PJM Market Monitoring Unit, "2006 State of the Market Report," pp. 169, 177-178, 195-199, located at http://www.pjm.com/markets/market-monitor/som-reports.html; PJM Southeast and Southwest Interface Pricing Point Consolidation Approach," August 31, 2006, located at http://www.pjm.com/etools/oasis/downloads/interface-pricing-point-consolidation.doc.

[48] Andrew L. Ott letter to Lance C. Stotts re: Duke Energy Carolinas Interface Pricing Arrangements, January 5, 2007, located at http://www.pjm.com/documents/downloads/agreements/duke-pricing-agreement.pdf.

[49] Andrew L. Ott letter to Robert Caldwell re: Progress Energy Carolinas, Inc. Interface Pricing Arrangements, February 13, 2007, located at http://www.pjm.com/documents/downloads/agreements/pec-pricing-agreement.pdf.

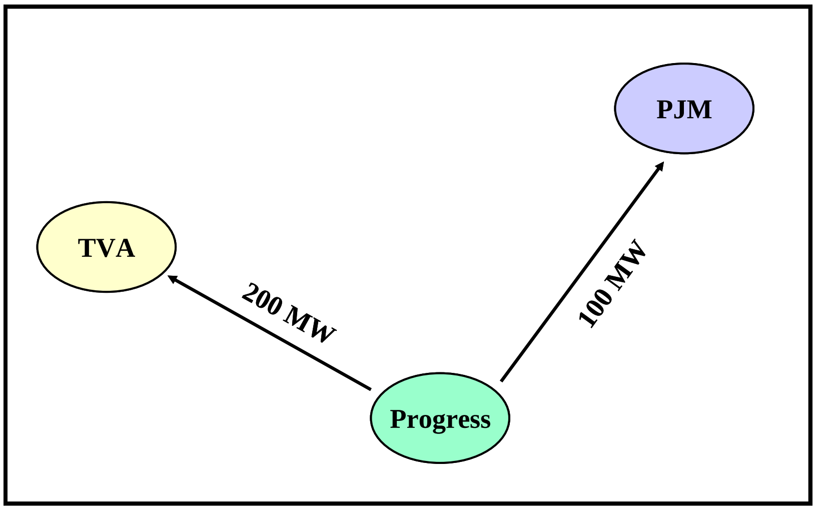
[50] Andrew L. Ott letter to Clay A. Norris re: North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement, March 19, 2007, located at http://www.pjm.com/documents/downloads/agreements/electricities-pricing-agreement.pdf .

[51] These agreements were also discussed in the 2007 State of the Market Report, pp. 212-213, , located at http://www.pjm.com/markets/market-monitor/som-reports.html.

authority areas, the net effect on PJM would be the same as if the import were sourced in the other balancing authority area.

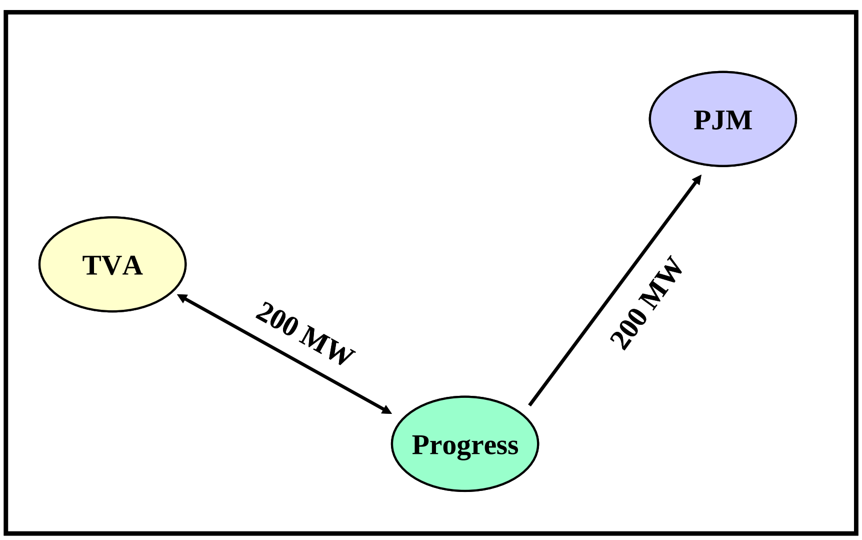
For example, suppose that in hour 1 Progress Energy was selling 100 MW to PJM and 200 MW to TVA, as shown in Figure 6.

Figure 6
Hour t Interchange Schedules



Now suppose that in hour 2 Progress Energy increased its exports to PJM to 200, offset by a 100 MW reduction in its exports to TVA, as shown in Figure 7.

Figure 7
Hour t+1 Interchange Schedules



The net change between hour 1 and hour 2 is a 100 MW increase in TVA generation, yet the PECGen price would apparently apply under the interface pricing agreement.

Perhaps the reason for the lack of provisions governing exports from the relevant control areas is a combination of an expectation that market prices will generally disfavor such exports and the likelihood that such exports to TVA would be providing PJM with favorable counterflow on its west-to-east constraints so it may not be in the interest of PJM transmission customers to discourage such exports. These considerations may not apply in other contexts, so other entities considering the use of provisions similar to PJM's interface pricing arrangements may need to have rules for periods in which exports as well as imports are occurring.

Under the agreements, Duke, Progress and the North Carolina Municipal Power Agency No. 1 agreed to provide confidential and auditable data to PJM concerning their load, aggregate system generation, aggregate energy sales and purchases on a one-minute or shorter basis.[52]

One principle that PJM adhered to throughout these changes in proxy bus definitions is that while these changes were implemented prospectively for the pricing of interchange transactions, PJM continued to calculate prices for the original proxy bus definitions and previously sold FTRs sinking at the original proxy bus locations continued to be settled based on these prices for the original proxy bus location.[53]

On the other hand, even more than in New York, the PJM experience shows the need to change proxy bus definitions over time, both to reflect the addition of controllable lines, changes in PJM boundaries and to improve pricing based on experience and the behavior of market participants.

C. ISO-NE Proxy Buses

The ISO-NE currently has six proxy buses for interregional schedules, three with the NYISO, two with the Hydro Quebec, one with New Brunswick.[54]. The ISO-NE proxy bus for its AC inter-connects with NYISO is located at Roseton. Like the NYISO, ISO-NE has a separate proxy bus located at Shoreham on Long Island for power scheduled to flow on the Cross Sound Cable, which is a controllable line (DC), and also has a separate proxy bus for schedules on the PAR controlled 1385 line connecting ISO-NE and Long Island. ISO-NE also has separate proxy buses for two distinct its DC interconnects with Hydro Quebec at Highgate and Sandy Pond. Finally, it has a proxy bus located at Keswick for deliveries from New Brunswick.

---

52 See the agreements cited in footnotes 51-53.

53 See for example, "PJM Southeast and Southwest Interface Pricing Point Consolidation Approach" August 31, 2006.

54 "ISO New England Calculation of TTC for External Interfaces and ATC for PTF Interfaces," Version 2.0, Issued on December 15, 2007.

IV. CONTROLLABLE LINES AND PROXY BUSES

The problems of applying multiple proxy bus pricing systems to scheduling a single level of tie line flows arise because the actual real-time flows are not affected by the proxy bus scheduling decision. This is a characteristic of schedules over open ties for which there is a single schedule for net flows over all of the tie lines. These problems do not arise for schedules over controllable lines if the system operator or line operator holds the actual flows over the line to match the schedule.

If the system operators dispatch generation to maintain separate tie line schedules and move generation up and down at different combinations of locations in order to increase or decrease flows on those tie lines, then the impact of these changes in schedules would be best modeled by establishing separate proxy buses for changes in interchanges over the distinct tie lines or sets of the lines. For example, if the system operators dispatch generation to maintain a separate tie line schedule on a controllable line, then market efficiency is improved by establishing a distinct proxy bus location for that line.

This practice has been followed by PJM, NYISO and ISO-NE, which have all established additional proxy buses to price schedules over controllable lines (Cross Sound Cable, 2005; Neptune, 2007; and 1385 Line, 2007).

CAISO Integrated Balancing Authority Filing
Docket No. ER08-_____-000
June 17, 2008

ATTACHMENT I

Opinion of the Market Surveillance Committee of the California Independent System Operator Corporation

Opinion on "Modeling and Pricing Integrated Balancing Areas under MRTU"

by
Frank A. Wolak, Chairman
James Bushnell, Member
Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO
May 7, 2008

1. Introduction

We have been asked to comment on the California Independent System Operator's (CAISO) proposal for modeling and pricing Integrated Balancing Authority Areas (IBAA) under the Market Redesign and Technology Upgrade (MRTU). IBAAs are neighboring Balancing Authority Areas (BAAs) that are not part of the California ISO Balancing Authority Area, but are incorporated into the CAISO's Full Network Model (FNM) because they are so closely interconnected with the CAISO through AC transmission facilities that the flows within these BAAs have substantial impacts on power flows within the CAISO. Multiple interconnection points between the California ISO BAA and the IBAA can result in loop flows in and out of the California ISO BAA and on the California ISO Controlled Grid that are difficult to model in the day-ahead market without detailed knowledge of the location of load and generation and the configuration of the transmission network in the IBAAs.

Currently, the practice is to model the inter-ties between the CAISO and neighboring BAAs as radial, essentially treating each connection as an independent "pipeline" into the CAISO system, analogous to a fictitious generation unit located at the tie point. These radial connections are assumed not to connect with each other outside the CAISO, and therefore flows over individual ties are assumed to create no "loop flows" that result in additional flows over other inter-ties. The current radial network model assumes that flows resulting from an import transaction will be confined to the interface through the "contract path" over which it is scheduled, although actual flows will follow all parallel paths into the CAISO. When loop or other inadvertent flows occur, this will lead to a divergence between scheduled day-ahead flows over these lines and the actual flows in real-time. For some IBAAs, the CAISO believes that this divergence between final day-ahead inter-tie schedules and real-time physical flows on these inter-ties will be small enough for the CAISO operators to manage these deviations in real-time with limited reliability and economic consequences. For now, interconnections with this set of BAAs will continue to be modeled as radial interconnections under MRTU.

However, for IBAAs that are more closely integrated with the CAISO BAA, the CAISO believes that radial treatment of these interconnections can result in day-ahead schedules that are sufficiently different from real-time power flows so as to create adverse reliability consequences and impose significant costs upon CAISO market participants. For these inter-ties, the CAISO proposal models the looped nature of the transmission network outside of the ISO BAA with the goal of obtaining day-ahead schedules that are more representative of real-time power flows. The CAISO proposes to apply this approach to the Sacramento Municipal Utility District (SMUD) BAA, which includes the systems of the Western Area Power Administration (WAPA), the Modesto Irrigation District (MID), and the cities of Roseville and Redding, California and the Turlock Irrigation District (TID) BAA.

Individual MSC members have participated in several teleconference and in-person meetings with CAISO staff to discuss the IBAA proposal. One MSC member attended the March 6, 2008 Stakeholder meeting on this topic at the CAISO. The MSC held a joint MSC/Stakeholder meeting on April 11, 2008 to hear stakeholder comments on this issue. A significant portion of that meeting was devoted to a discussion of the experience of eastern CAISOs with pricing injections and withdrawals from neighboring BAAs. We have greatly benefitted from our interactions with CAISO staff and stakeholders on this very complex issue.

In this opinion, we first summarize our understanding of the CAISO's IBAA proposal and what it is designed to achieve. We support the CAISO's "single hub" price proposal. We believe this is superior to the previous multiple IBAA proposal because it severely limits the ability of suppliers to extract revenues from CAISO market participants without providing any significant reliability benefits. We also continue to support an IBAA solution with more pricing points into the CAISO BAA, but only if the CAISO is given access (by neighboring IBAAs) to detailed information on the day-ahead schedules of all generation units and inter-ties outside of the CAISO control area that exert an influence on power flows in the CAISO BAA and if it can be demonstrated that these multiple pricing points improve market efficiency and system reliability. Absent such information and its associated benefits, the CAISO proposal of a single aggregate IBAA with an import and export price appears to be the best available way to obtain day-ahead schedules that are accurate predictions of real-time flows that do not involve significant monetary transfers from CAISO participants to these entities.

2. The CAISO IBAA Proposal

The issues that the CAISO IBAA proposal deals with arise whenever electricity is traded between BAAs. These so-called "seams issues" include questions such as: How should transactions between BAAs be priced? How should their impacts on network flows be accounted for in the day-ahead and real time markets in order to promote reliability and economic efficiency? How should deviations from scheduled flows and the costs they impose be compensated for? Procedures for handling these issues have evolved over decades in the former vertically-integrated, regulated monopoly regime, but as CAISO market rules have changed and inter-BAA trade has increased, the answers to these questions have had to be revisited.

There is no uniformly best solution to many seams issues when adjacent BAAs use very different mechanisms to manage transmission congestion. This is particularly true for scheduling and pricing inter-BAA transfers. On one hand, power flows entering a BAA at different interfaces have different economic value to that BAA because of the configuration of the transmission network and location of load and generation in the BAA. Thus, it is intuitively appealing to reward suppliers in other BAAs for injections at the more valuable locations. On the other hand, because of the way that deviations from scheduled power flows at interfaces between BAAs are managed, there are strong incentives for providers to claim that their power will be injected at the most lucrative (for the provider) interfaces as measured by the locational marginal prices (LMPs), even though power might flow in real-time over the less valuable interfaces. As a result, if the California ISO attempts to provide incentives to neighboring BAAs to supply power to more valuable interfaces, the result may simply be more payments to suppliers in those BAAs, with no significant changes in the locations and magnitudes of inter-BAA flows. Although there are mechanisms for seams management that can in theory improve the efficiency of inter-area transactions, these are not practical under present institutional arrangements in the Western Electricity Coordinating Council (WECC).[1]

The CAISO's IBAA proposal attempts to balance a number of competing goals under the present WECC protocols for inter-BAA transactions. The first is to obtain a reasonable accurate representation of real-time flows into CAISO BAA from the results of the day-ahead market based on the information these IBAAs are willing to make available to the CAISO operators about their internal load and generation schedules. The second is to set prices for injections and withdrawals into the CAISO BAA that limit the incentives market participants have to profit from these transactions without providing any reliability or market efficiency benefits to the CAISO BAA. The third goal is to allow each entity the option to designate specific resources within the IBAA as dynamic or non-dynamic generation resources with their own LMP, what the proposal calls Dynamic Resource-Specific Resources or Non-Dynamic Resource-Specific System Resources. The CAISO's current IBAA proposal will not implement this feature until a later date.

The CAISO proposal will establish a "single-hub" default pricing rule for transactions between the CAISO and the SMUD/WAPA/MID/TID IBAA. All imports to the CAISO from SMUD/WAPA/MID/TID IBAA will be priced based on the LMP at the Captain Jack Sub-Hub or Proxy Bus and all exports from the CAISO to SMUD/WAPA/MID/TID IBAA will be priced at the SMUD Sub-Hub or Proxy Bus. This single pricing hub with different export and import prices limits the incentive that suppliers have to use facilities outside the CAISO BAA to misrepresent the location of imports or exports in order to increase their revenues or decrease their costs at the expense of CAISO market participants when actual flows will occur at different interconnections. For instance, the current CAISO proposal makes it less likely that it will be

[1] For a discussion of some of these theoretically elegant solutions, see B. Kim and R. Baldick, "Coarse-grained Distributed Optimal Power Flow," IEEE Transactions on Power Systems, 12(2): 932–939, May 1997. At one extreme, flows through each transmission line connecting two systems could have its own price, with one system compensating another at the relevant real-time LMP if the real-time flow deviates from scheduled flows. This will provide incentives for suppliers in one system to provide accurate day-ahead schedules. However, under current procedures for compensating for imbalances between control areas, this is not possible. This is because adjacent control areas provide compensation only for net imbalances across all interfaces, not for deviations at individual interfaces. For instance, 200 MWh might be scheduled in the day-ahead market to flow into the California ISO Control Area from the SMUD control area, and this schedule might specify that the flow will be split evenly between two inter-ties between the control areas. Suppose that in real-time virtually all of the flow is through a line that is less valuable for the California ISO; however, if the total flow is still 200 MWh, SMUD will not owe any compensation to the California ISO Control Area. A further disincentive to efficient inter-area transaction management is that if a net imbalance does occur in real-time, no financial compensation occurs; instead, compensation takes the form of paying back physical energy (on an MWh for MWh basis) at a later time.

An alternative approach is possible if both control areas use LMPs to price congestion, and use consistent models and data sets for each other's systems. This can result in consistent LMPs in the sense that one system can obtain reasonable estimates of LMPs at locations in the other system. Then suppliers wishing to sell power from one system to a neighboring system can be paid the local LMP at their point of injection by the neighboring system, which then would also pay the congestion cost from that point to any interface. This eliminates any economic rewards associated with misrepresenting the source of power transfers from one control area to the other. This solution is not possible where (1) adjacent control areas do not use consistent LMP-based congestion management systems, (2) data on neighboring systems is inadequate, or (3) one control system agrees to disregard congestion and losses in other systems when calculating LMPs. All three of these conditions apply to the relationship of the CAISO MRTU congestion management process with the ones used in neighboring control areas.

possible to extract revenues from the CAISO BAA by scheduling energy out of the CAISO BAA at a low-price location and scheduling that same energy back in at a high-price location. Pricing all imports at Captain Jack and all exports at SMUD makes this strategy much less profitable because the LMP at Captain Jack is likely to be less than or equal to the LMP at the SMUD Sub-Hub the vast majority of hours of the year. Consequently, one important advantage of the CAISO's single hub solution is that it limits the incentive of market participants to engage in strategies that result in little or no net injection of energy into the CAISO BAA, but profit from price differences at different interfaces between the CAISO BAA and the IBAA. It is important to emphasize that these pricing point rules apply to all scheduling coordinators (SCs) that inject power into the CAISO BAA from this IBAA or withdraw power from CAISO BAA and sink it in this IBAA, so that all SCs have a strong financial incentive not to engage in these scheduling strategies.

3. Assessing the CAISO's IBAA Proposal

This section assesses the two major components of the CAISO's IBAA proposal. The first is the designation of a single IBAA pricing point rather than multiple IBAA pricing points as was the case in the previous CAISO proposal. The second is the use of a different pricing point for imports and exports into the CAISO BAA from the SMUD/WAPA/MID/TID region. We also note some potential complications associated with having separate import and export prices for the single pricing point and the existing CRR holdings of CAISO market participants and potential conflicts between the CAISO proposal and pre-existing contractual arrangements between the CAISO and the SMUD/WAPA/MID/TID region.

3.1. Simplifying Network Model for CAISO and Neighboring Balancing Authority Areas

One lesson from the current zonal market design in California is that there is a significant risk of adverse unintended consequences from attempts to simplify the full network model in the day-ahead market and still obtain final energy schedules that are accurate representations of real-time power flows. However, without detailed information on the configuration of the transmission network and day-ahead schedules of all generation units and loads in the neighboring IBAAs and scheduled injections and withdrawals from neighboring BAAs besides the CAISO into these IBAAs, it is impossible to determine the true source of supply of energy into the CAISO BAA from the SMUD/WAPA/TID/MID region. Without this level of visibility of the neighboring IBAAs by the CAISO operators, we do not believe setting more than one IBAA pricing point will increase market efficiency and system reliability. The experience of the eastern ISOs with creating multiple aggregate scheduling points with neighboring BAAs suggests that this creates significant opportunities for market participants to exploit hub price differences while providing inadequate incentives to reduce the difference between scheduled and actual flows on the inter-ties between the two BAAs. The PJM market initially had multiple pricing hubs with neighboring BAAs, but found that this primarily created opportunities for market participants to exploit inability of the PJM operators to determine the true source of supply and earn the higher price for injections and pay the lower price for withdrawals. As a result, PJM has now set a single hub price with neighboring BAAs.

Because inter-tie-level imbalances between the CAISO BAA and the SMUD/WAPA/TID/MID region are not settled at the real-time price, but are instead settled on net flows across all inter-ties on a MWh-for-MWh basis, we see little reason to expect that setting multiple hub prices in the day-ahead and real-time markets will provide incentives for market participants to have inter-tie-level final schedules that are close to real-time flows. As was emphasized by several participants at the March 6, 2008 Stakeholder meeting, it is possible for market participants to use non-CAISO transmission facilities to alter the deemed source of power flowing into the CAISO BAA. For example, a firm supplying from the Pacific Northwest could actually be injecting power at the Captain Jack inter-tie and schedule a transaction that uses transmission facilities not controlled by the CAISO to move this power from Captain Jack to SMUD. Then it could submit a schedule from the SMUD aggregation point to the CAISO BAA to receive the SMUD hub price instead of the Captain Jack price for this electricity. Except in very special circumstances, it is impossible for the CAISO to determine where the energy injected at the SMUD aggregation point was sourced. Yet the actual source of the energy is a key determinant of its value to electricity consumers in the CAISO BAA. The "true" source of the incremental power can have very different impacts on congestion and losses within the CAISO system. Simply put, incremental generation at SMUD would likely be much more valuable to CAISO consumers than incremental generation at Captain Jack for purposes of managing congestion on the CAISO Controlled Grid.

Within the CAISO, the source of incremental power is identified though the balancing process. If the actual generation at a source is greater than the scheduled output, then the generation has been increased. If the generation is promised at a source, but does not materialize, firms are responsible for paying for the difference at the resulting balancing price at that location. The key problem with seams as now managed in the Western Electricity Coordinating Council (WECC) is that this balancing process has little geographic differentiation. Transactions are balanced at the BAA level, rather than at the nodal level, across BAA boundaries. If the total amount energy flowing from the SMUD/WAPA/MID/TID region in real-time is equal to the sum of net schedules between this region and the CAISO BAA, then the systems are considered balanced. This is true even if power that is scheduled at SMUD is provided from somewhere else within the same BAA. Thus, there is no penalty for delivering power at inter-ties besides the ones it was scheduled on.

For all of these reasons, we support a single pricing location for the SMUD/WAPA/MID/TID region. This should provide entities transferring energy in and out of the CAISO BAA from and to the SMUD/WAPA/MID/TID region with an incentive to schedule resources in a least-cost manner. This pricing mechanism will at least eliminate the incentive to schedule power in a way that takes advantage of the inadequacies of the WECC-wide balancing process as it affects CAISO markets. Firms will have a strong incentive to schedule imports to the CAISO BAA from the least cost (to them) location in their region because they will receive the same price for imports regardless of where these imports come from. Similar logic applies to the case of withdrawals. The neighboring IBAA have an incentive to withdrawal energy from the CAISO BAA only in those instances when it truly is more costly to produce energy in their IBAA than it is to purchase it from the CAISO. This alignment of incentives is also likely to improve the agreement between day-ahead schedules and real-time flows between the CAISO BAA and the SMUD/WAPA/MID/TID region.

3.2. Different Import and Export Prices

As noted above, it is impossible for the CAISO to determine the true source of energy injected into the CAISO BAA from a neighboring IBAA or the true sink of a withdrawal from the CAISO BAA given the information the neighboring IBAAs currently provide to the CAISO operators. Consequently, the CAISO must make some assumption about where it believes injections are likely to be sourced from and locations where withdrawals are likely to sink to in the neighboring IBAAs. We believe it is reasonable and prudent for the CAISO to make these choices in a manner that enhances rather than detracts from system reliability and market efficiency in the CAISO BAA.

In a sense, the CAISO's proposal assumes a worst-case scenario for the source and sink. Specifically, rather than assume the incremental energy is being supplied from the highest price location in the IBAA, the CAISO assumes that it is being supplied from distant generation in the Pacific Northwest and therefore uses the Captain Jack LMP. Similarly, rather than assume withdrawals from the CAISO BAA are sinking at a low-price location in the Pacific Northwest, the CAISO assumes that this energy is sinking at the high-price location in the SMUD region and therefore uses the SMUD price.

As noted above, this pricing policy increases the likelihood that the increment of energy necessary to schedule an injection in the CAISO BAA is in fact coming from Captain Jack or some other location in the Pacific Northwest and the withdrawal from the CAISO BAA is in fact going to the SMUD BAA. This logic also implies that the day-ahead schedules are likely to be closer to real-time flows than would be the case without this IBAA pricing approach. These incentive benefits do not come without cost, however. To the extent that the Captain Jack price is lower than the cost of generation within SMUD, for example, customers within the CAISO will not be able to pay an adequate price for power sourced at SMUD and such trading opportunities may be lost. We note, however, that the CAISO's latest proposal offers a means to maintain these trading opportunities by permitting SMUD to obtain a higher price for its generation if it provides more detailed information to the CAISO that substantiates that the SMUD generation is actually supporting the identified inter-tie transaction. This is unfortunate, but paying the higher SMUD price to all power imports would likely be much worse because of the opportunities introduced by inefficient seams management and balancing energy pricing.

The close relationship between the Malin and Captain Jack inter-ties highlights a related concern addressed by the import/export pricing rule. If a single price were used for both imports and exports into the IBAA, this single price would likely be higher than the Captain Jack price. It would then be possible to procure power at Malin and schedule it into the CAISO at Captain Jack. This is in effect a "circular schedule," essentially sourcing and sinking the power at places with no electrical difference, but with potentially significant price differences. Setting the price of imports into the CAISO from the IBAA at the Captain Jack price recognizes the reality that firms trying to import power into the CAISO from one of the IBAA's inter-ties will choose to procure that power at the cheapest source—which is likely Captain Jack.

We believe that the poor experience of the eastern ISOs with setting multiple pricing hubs and a single price for imports and exports, recommends the current CAISO approach of setting different prices for imports and exports. As the CAISO gains experience under MRTU with this IBAA pricing approach, it can consider increasing the number of pricing locations if it is granted access to the data necessary to determine with sufficient confidence the likely source of energy injected in the CAISO BAA or the sink for energy withdrawn from the CAISO BAA and if there are clear efficiency benefits of moving towards such a pricing alternative.

3.3. Congestion Revenue Rights and the IBAA Proposal

There is one complication with the current IBAA proposal with respect to Congestion Revenue Rights (CRRs) that should be addressed. Because the CAISO would be charging imports and exports different prices it is unclear what price will be used to settle CRRs between the CAISO and the SMUD/WAPA/MID/TID IBAA. Going forward this requires the CAISO to specify two different nodes in the SMUD/WAPA/MID/TID IBAA that market participants can source or sink their CRRs. There are a number of options for settling CRRs with separate import and export prices. The current CAISO proposal is to use the direction of the CRR to determine the settlement price. If the CRR is defined in the import direction, then its sink is the CAISO and it will settled at the IBAA import price. If the CRR is in the export direction, then its sink is in the IBAA and it must be settled at the IBAA export price. The only outstanding concern is for pre-existing CRRs that were not defined in this manner at the time they were released, so their settlement price locations must be adjusted to match the IBAA pricing rules and this could result in revenue inadequacy. The CAISO expects any such impacts to be small relative to the entire pool of congestion revenues over a month, but it will be able to test for revenue adequacy in advance. If any CRR revenue inadequacy is identified, the CAISO proposes to use the monthly CRR Balancing Account to cover any revenue shortfall that may or may not occur.

3.4. The Interaction with Pre-Existing Operating Agreements

One other issue that was the subject to significant discussion during the stakeholder meetings is the relationship between the new IBAA proposals and any pre-existing agreements for the management of losses on shared inter-ties. Some stakeholders, such as Transmission Agency of Northern California (TANC) and Silicon Valley Power (SVP), have argued that existing contracts specify a reciprocal arrangement in which each party will manage losses on its own part of the transmission network, even though loop flow is causing each party's transactions to incur losses on the other party's portion of the network. It is our understanding that the reciprocal arrangement essentially assumes that these loop flow effects balance out.

The new proposal for IBAA pricing shift the paradigm for loss cost-allocation from a “payment-in-kind" approach to one in which the cost of losses are incorporated into the prices of transactions using the CAISO system. Under the IBAA proposal, marginal loss charges for flows on CAISO transmission facilities apply only to transactions scheduled into and out of the CAISO BAA. In other words, parties will be charged for the losses caused on the CAISO system by transactions scheduled into or out of the CAISO system. To the extent that firms are required to pay in-kind for their losses by reducing their withdrawals in addition to paying LMPs that reflect marginal losses, this could be construed as double-charging for losses. However, our understanding of the reciprocal arrangement is that it covers losses caused on one system for transactions scheduled *on the other system*. The current CAISO proposal deals with the effect of losses on the CAISO system of transactions scheduled *on the ISO system*. To the extent that the

CAISO does not charge IBAA parties for the loss consequences of schedules using only IBAA facilities, this will not change.

We are not in a position to comment on the exact nature of these contractual commitments, other than to recognize that the issue has been raised. We would also like to point out that incorporating losses on the CAISO network into LMPs for sales into and out of the CAISO BAA is a much more efficient means of compensating for the effect of losses than the “payment-in-kind" approach. Under an LMP market, the system operator is effectively finding the most least-cost (based on offers and bid submitted) way to compensate for losses and including those costs into the prices seen by all market participants. The LMPs also provide all market participants with a price-signal of the cost of the increased losses caused by the transaction. Under a payment-in-kind approach, users provide the physical compensation for the losses themselves. It is an approach somewhat analogous to having each unit provide its own operating reserves, rather than pooling those responsibilities amongst a larger network.

If there is a determination that pre-existing contractual arrangements require a payment-in-kind approach for losses for some of the transactions, ideally the requirement could be met while still maintaining the efficiency benefits of the LMP approach. This could be accomplished through a mechanism such as a "losses-only" revenue right (LRR). This LRR would be similar to a congestion revenue right (CRR) except that it would pay the right holder only the component of the LMP difference caused by losses rather than the entire LMP difference. To avoid distorting scheduling incentives, this quantity of LRR would have to be set at some pre-determined level rather than linked to the amount of daily schedules into and out of the CAISO system.

4. Adapting to Changing Market Conditions

As noted earlier, there is no optimal solution to modeling and pricing transactions between the CAISO and neighboring BAAs given the current WECC protocols for settling deviations between neighboring BAAs. A clearly superior solution would be to settle inter-tie-level real-time deviations between neighboring BAAs at the real-time LMP at that inter-tie. All parties could then be confident that power is being delivered at the location at which it has been scheduled, and that parties responsible for deviations from that schedule would bear the full costs caused by those deviations. We hope that the neighboring IBAAs will provide the necessary information to the CAISO so that it can move toward this solution as soon as possible. More broadly, we urge western BAAs to negotiate seams agreements that allow this sort of imbalance pricing and seams management.

Because the transmission network configuration between the California ISO and the SMUD/WAPA/MID/TID IBAA is likely to change, the CAISO should reserve the right to change the collection of proxy buses that comprise the import and export pricing points. We recommend a stakeholder process justifying the need to change the status quo and the describing the advantages of the proposed change, with the approval by the California ISO Board or in emergency situations the simply the approval the CAISO management with ex post review by the California ISO Board. Our key point is the CAISO must have the flexibility to adapt the import and export pricing points to changing conditions in the CAISO and IBAA BAAs if the CAISO’s IBAA proposal is to achieve the two main goals described above.

ATTACHMENT J

CAISO Board Documents

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Steve Greenleaf, Director, Regional Market Initiatives

Anjali Sheffrin, Chief Economist / Director of Market and Product Development

Date: May 13, 2008

Re: ***Decision Regarding Integrated Balancing Authority Areas Proposal***

This memorandum requires Board action.

EXECUTIVE SUMMARY

Since early in the Market Redesign and Technology Upgrade (MRTU) process the ISO recognized the need to model in detail certain neighboring Balancing Authority Areas (BAAs).[1] The affected systems are those in which the power flows on these systems have a large impact on power flows within the ISO Controlled Grid. The ISO determined that in order to accurately and reliably manage congestion on the ISO Controlled Grid under MRTU, the ISO has to accurately model in its Full Network Model (FNM) the power flows or network effects on the ISO's control area arising from such integrated external areas as well as provide prices that do not provide the incentive to inappropriately schedule at the interties to and from the IBAAs.

Under the ISO's IBAA proposal, the ISO is proposing to establish:

1) the Sacramento Municipal Utility District (SMUD) BAA[2] and the Turlock Irrigation District (TID) BAA as an Integrated Balancing Authority Area (IBAA) effective as of the go live date for MRTU;
2) the specific method of modeling and pricing transactions to and from the SMUD and TID BAAs;
3) the measures necessary to address the impact on Congestion Revenue Rights (CRRs) in the event that future IBAAs are adopted during the term of released CRRs; and
4) the proposed process for creating new, or modifying approved, IBAAs.

[1] The ISO originally referred to these entities as Embedded Control Areas and Adjacent Control Areas, but now refers to them as Integrated Balancing Authority Areas or IBAAs.

[2] In addition to SMUD's transmission system, the SMUD Balancing Authority Area also includes the systems of the Western Area Power Administration (Western), the Modesto Irrigation District (MID), the City of Redding (Redding) and the City of Roseville (Roseville).

Specifically, the ISO proposes to model the IBAA systems in a manner that allows the ISO to determine as accurately as possible the effect of intertie transactions between the ISO and the IBAA in the ISO's MRTU Full Network Model (FNM). Such detailed modeling is necessary to manage congestion as accurately as possible on the ISO Controlled Grid. The ISO's IBAA modeling methodology is explained in Section 1 of the Discussion section of this memo.

With respect to pricing, the ISO proposes to establish a "single-hub" default pricing rule for pricing intertie transactions between the ISO and the SMUD and TID IBAAs. As further explained in Section 3 below, all imports to the ISO from the SMUD and TID IBAAs will be priced based on the Locational Marginal Price (LMP) calculated at the Captain Jack Sub-Hub or Proxy Bus, while all exports from the ISO to the SMUD and TID IBAAs will be priced at the LMP calculated at the SMUD Sub-Hub or proxy bus. The ISO proposes that alternative pricing options will be available if the ISO is provided more detailed information regarding the resources supporting a specific scheduled intertie transaction and there is a demonstrable benefit to the CAISO system of such an arrangement. While the ISO originally contemplated adoption of a more granular system resource-specific based pricing regime, the ISO has now concluded that such pricing can lead to infeasible schedules and be subject to significant and gaming concerns, absent specific identification and verification of the resources supporting intertie transactions. Absent such a demonstration, the ISO is concerned that it would schedule and pay intertie transactions on a basis that does not reflect their value to the ISO and its customers for purposes of accurately and efficiently managing congestion on the ISO Controlled Grid. The Market Surveillance Committee's Opinion also addresses the IBAA pricing issue and is included as **Attachment A**.

With respect to CRRs, with the transition from the more granular approach contemplated previously to the single-hub approach and the default pricing rule (with separate prices for imports and exports), it will be appropriate for the ISO to view the CRRs that were released in the first annual CRR release process conducted during 2007 as "previously-released" CRRs and to apply the provisions outlined in Section 3, below regarding the reconfiguration of such CRRs to comport with the Single-Hub approach. The CAISO proposes that holders of "previously-released" CRRs be provided a one-time opportunity to elect to align the CRR source and sink definition of the CRRs obtained through the allocation process to align these with the market settlement under the adopted IBAA structure.

In conclusion, the ISO believes that the adoption of the SMUD and TID IBAA, the proposed modeling and pricing mechanisms and other associated IBAA changes will best support the following important objectives of MRTU:

1) feasible forward market schedules;
2) more effective congestion management solutions that will reduce uplift costs and other market inefficiencies; and
3) eliminate inappropriate scheduling incentives and pricing signals likely to result if the IBAA modeling and pricing mechanisms are not aligned.

For purposes of initial implementation, the ISO is clearly placing greater weight on objective (3) above. This is in large part due to the lack of detailed information regarding the location of the marginal resources supporting intertie transactions between the ISO and the proposed IBAAs. On an interim and long-term basis, once more information is provided to the ISO, further refinements can be made to the IBAA modeling and pricing methodology to further enhance the accuracy of the ISO's overall congestion management solutions. The ISO discusses those enhancements in Section 1, below. As the ISO moves forward with these enhancements, the ISO will adhere to the consultation, stakeholder and FERC process outlined in Section 4, below.

MOTION

> ***Moved, that the ISO Board of Governors approves the Integrated Balancing Authority Area (IBAA) proposal, as detailed in the memorandum, and related attachments, dated May 13, 2008, and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all of the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the IBAA proposal, and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to enter into alternative settlement arrangements as appropriate for intertie transactions between the ISO and IBAA entities or other affected entities based on the provision of additional resource specific detailed data and a demonstrated benefit to CAISO customers, and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all of the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement such agreements, if any.***

BACKGROUND

The ISO's need for enhanced modeling in neighboring Balancing Authority Areas was outlined and codified in ISO MRTU Tariff filings beginning early in 2006 and acknowledged in the *September 2006 Order*.[3] In that order, FERC supported the ISO's commitment to include more information concerning what were then referred to as "adjacent and embedded control areas" (now IBAAs) in the FNM as soon as possible.[4] FERC agreed that the ISO should operate the ISO Controlled Grid using the most accurate model of internal and external areas that can be developed.[5] In addition, FERC directed the ISO to work with external control areas to develop the model more fully in the future, but noted that the ISO can only model external areas to the extent it has the information to do so.[6]

Pursuant to FERC's direction that the ISO work with external Balancing Authority Areas (BAAs) to develop the model more fully in the future, and due to the physical characteristics of the SMUD and TID BAAs, the ISO focused its efforts to model the SMUD and TID BAAs as IBAAs. In addition, consistent with FERC's direction, for the purposes of the initial release of

---

3 See the FERC's September 21, 2006 Order on that filing, *California Independent System Operator Corporation*, 116 FERC ¶ 61,274 (2006) ("September 2006 Order"). Further, the need to model the SMUD and TID BAAs was included in the February 9, 2006 MRTU Filing and in the subsequent development of the Business Practice Manual (BPM) for the FNM. For example, on July 31, 2006, the ISO published a draft BPM for the FNM indicating that the SMUD; Western Area Power Administration, United States Department of Energy ("Western" or "WAPA"); Modesto Irrigation District ("MID"); and TID are "Adjacent Control Areas that may be included in the FNM because they have transmission facilities that operate in parallel with the ISO Control Area and are highly interconnected to the ISO Control Area."

4 *September 2006 Order* at P 45.

5 *Id*.

6 *Id*. *See also* MRTU Tariff § 27.5.3.

CRRs, the ISO used a FNM that included the expanded detailed modeling of the SMUD and TID BAAs, which is the same modeling approach reflected in SMUD and TID IBAA proposal outlined herein.

Originally, in the 2006 timeframe, the ISO considered modeling IBAAs in a closed loop fashion. Modeling the IBAAs in a closed loop fashion would have required the ISO to obtain detailed load forecast and resource-specific scheduling information from the IBAAs. During the December 2006 FERC Technical Conference on seams, FERC Commissioners and staff expressed the desire that parties move towards the more collaborative data exchange process. Pursuant to this direction, the ISO took additional measures to continue discussions towards furthering this effort with what it had previously identified as the most integrated BAAs. Due to the opposition to moving towards modeling in a closed loop manner, the ISO decided to modify its proposal in the late winter and early spring of 2007 in a way that reduced the information/input requirements but still retained the modeling accuracy needed to support MRTU.

Beginning in the late spring and early summer 2007, the ISO again engaged the IBAA entities in discussions regarding the modeling approach and pricing of their systems. These discussions concluded in October/November 2007 when the ISO concluded that further bilateral discussions toward reaching agreement on the modeling and pricing methodology would not be effective. In December 2007, the ISO published discussion papers related to this matter and initiated broader stakeholder discussions. The ISO has been engaged in these broader stakeholder discussions over the last five months. Further detail regarding the stakeholder process is included in the *Stakeholder Process and Feedback* section of this memo and in **Attachment B**.

DISCUSSION

There are four primary elements to Management's IBAA proposal: 1) the adoption of the SMUD and TID IBAA based on the proposed IBAA modeling approach, 2) pricing of transactions to and from the IBAA(s), 3) a process for creating new, or modifying existing, IBAAs, and 4) the impact of the IBAA proposal on CRRs.[7] In addition, the Management proposal includes a opportunity for alternative pricing arrangements provided the ISO is able to obtain additional data that can be used through is market processes and there are demonstrated benefits to the ISO customers of such alternative arrangements. Each of these elements is discussed below. Management also includes a discussion of the major areas of concern raised by stakeholders.

1. Proposed IBAA Modeling Methodology

The ISO's FNM is a detailed mathematical representation of the physical transmission system operated by the ISO, including the constraints and interfaces of the ISO Controlled Grid. The FNM incorporates a representation of the interconnections between the ISO and other BAAs both in California and in neighboring states that are not part of the ISO Controlled Grid. Intertie transactions (imports and exports) between the ISO BAA and these other BAAs can affect the flows and constraints on the ISO Controlled Grid. In order to manage congestion as accurately as possible on the ISO Controlled Grid it is important to accurately reflect the effect of intertie transactions in the FNM to the extent feasible.

In trying to accurately reflect the effect of intertie transactions with other BAAs in the FNM, it is important to recognize that the ISO neither controls the dispatch, nor necessarily knows the location of the generation and loads located in the other BAA that are dispatched to implement intertie transactions. Stated differently, the ISO cannot ensure that an intertie transaction scheduled day-ahead at any particular Intertie Scheduling Point is consistent with the location of the generation

[7] The ISO IBAA Modeling and Pricing is further detailed in the Draft Final Proposal and other Discussion Papers posted on the ISO website at http://www.ISO.com/1f50/1f50ae5b32340.html.

and loads actually dispatched to implement the intertie transaction in real time. One intended purpose of the IBAA modeling and pricing provisions is to ensure effective congestion management and that there will not be large differences between scheduled intertie transactions (and scheduled flows) with the IBAAs and actual interchange transactions (and actual flows) with IBAAs which would impact redispatch in real-time.

Ultimately, the ISO understands it is necessary to model each of its interconnections with other BAAs in a closed loop or highly integrated manner. A closed loop model would mean that the BAAs would share detailed information about the dispatch of resources (generation and loads) internal to each BAA with the other BAAs. Closed loop modeling requires the agreement of the other BAAs and currently there is a great deal of reluctance to support the level of data exchange that is needed to implement a closed loop model in the West. While the ultimate goal of closed loop modeling is not achievable in the near term, this should not deter the ISO from making improvements where sufficient data is available. The ISO's IBAA proposal means that at the start of the MRTU markets interchange transactions using the SMUD and TID BAAs would be modeled in a more detailed manner reflecting the greater amount of information and data the ISO has due to the fact that the SMUD and TID BAAs formerly were part of the ISO BAA.

The ISO summarizes below the salient details of IBAA modeling approach under both the previously recommended Multiple Hub or Sub-Hub based IBAA methodology as well as the now recommended Single-Hub based IBAA methodology. It is important to note that certain core aspects of the modeling methodology are common to both the Sub-Hub and Single-Hub IBAA methodologies. These core elements to the IBAA modeling methodology are discussed in the next section (Section 1.1, below).

1.1 Core Elements of the IBAA Modeling Methodology

The ISO's IBAA modeling methodology is intended to improve the FNM's accuracy in modeling the IBAA in order to improve the congestion management process on the ISO Controlled Grid. As noted above, improved modeling will lessen discrepancies between: (i) modeled flows and congestion in the Day-Ahead Market, and (ii) actual flows and congestion in real time on the ISO Controlled Grid. Improved modeling of external systems in the FNM and lessen the discrepancies between modeled and actual flows and increase the accuracy of the LMPs in reflecting system conditions and congestion. This will mean less redispatch in real-time for unanticipated congestion.

The proposed basic approach for modeling the SMUD and TID IBAA will not be either a closed loop or a radial format.[8] Rather, the proposed modeling approach in the FNM builds upon existing available information and uses a simplified or reduced model of the actual SMUD BAA and the TID BAA.[9] A closed loop model would reflect the flows between the IBAA and the ISO based on information regarding the actual location and physical operating characteristics of the generation and load within the interconnected BAA. In contrast, the proposed approach models the physical resources internal to the IBAA network using individual or aggregated System Resource injections at dominant transmission bus

---

8 *See Modeling & Pricing Discussion Paper* at 20-26 (Appendix 3 describing "Modeling Option 2" that is similar to modeling a BAA in a closed loop fashion).

9 The SMUD, Western, MID, and TID transmission systems were formerly part of the ISO BAA. Prior to the establishment of their own control area, the ISO had the modeling information for the SMUD and Western transmission systems that will be used in modeling the SMUD and TID IBAA. Additional data is available from WECC base case power flow models.

locations within the IBAA network.[10] The individual or aggregate System Resources will be used to distribute and model import and export transactions between the ISO and the IBAA.[11]

In summary, the proposed core modeling approach will improve the accuracy of modeling flows internal to the SMUD and TID IBAA and the accuracy of modeling flows between the IBAA and the ISO -- both for the purpose of capturing the effects of such power flows on the ISO Controlled Grid. The proposed approach also maintains the existing scheduling practices between BAAs and avoids the exchange of additional, more detailed data between the two BAAs and the ISO for the purpose of running the ISO markets.

1.2 IBAA Multiple Hub or Sub-Hub Modeling Methodology

Initially, at the start of the ISO's IBAA effort, the ISO advocated what it characterized as a "Sub Hub" IBAA modeling approach. The ISO's Sub-Hub IBAA Modeling approach would map submitted interchange schedules back to the identified supporting System Resource. Under the Sub-Hub approach, these would be the SMUD, Western, MID, Roseville, TID, and Captain Jack System Resources or Hubs. Once the schedules are mapped back, the ISO would model injections as coming from the identified System Resource. For aggregated System Resources, such as the SMUD and Western Hubs, the injections would be distributed to the locations/facilities that comprise the Aggregated System Resources pursuant to pre-determined Intertie Distribution Factors (IDFs). This process allows the ISO to model the actual flows that will result from the scheduled interchange for purposes of managing congestion on the ISO Controlled Grid. The degree of modeling accuracy with this approach is of course dependent on an accurate representation of the supporting System Resource (e.g., SMUD Hub, Western Hub, Captain Jack, etc.) by the scheduling entity. Based on concerns raised by the Department of Market Monitoring (DMM) and the Market Surveillance Committee (MSC) about relying on such representations, the ISO now recommends the Single Hub approach outlined in the next section. However, the ISO will retain the potentially more accurate Sub Hub based modeling functionality should an agreement be reached between the ISO and external BAAs to provide the ISO with specific and verifiable information regarding the resources supporting identified interchange transactions.

1.3 IBAA Single-Hub Modeling Methodology – Management Proposal

The Single-Hub IBAA methodology utilizes the core modeling approach outlined above in Section 1.3 and is similar in application to the Multiple Hub based modeling approach described in Section 1.2, except that whereas the Multiple Hub would allow an entity to specify the underlying System Resource (initially based on the six System Resources discussed above), the Single Hub would map all scheduled *import*s from the IBAA to the ISO to a common location (such as the Captain Jack System Resource or an aggregation of supply resources), and all scheduled *exports* from the ISO to the IBAA to a different location (such as the SMUD Hub System Resource or an aggregation of demand resources). The ISO believes that the Single-Hub approach maintains modeling accuracy and mitigates arbitrage concerns and maintains consistency between scheduling and pricing.

1.4 Future Enhancements to IBAA Modeling

---

10 The ISO notes that the term it is using for modeling IBAAs is an "aggregated System Resource," and in this defined term, the word "resource" is broader than generating resources. As noted however, the use of System Resources in modeling of an IBAA will include other facilities (e.g., substations and dominant transmission buses) that are not literally generating resources.

11 Initially, the ISO contemplated using a model that approximated a closed loop model and a detailed exchange of information. After discussion with the BAAs and further consideration by the ISO, the ISO developed the proposed approach and determined that its use can achieve accurate congestion management outcomes.

The ISO recognizes that both the Multiple or Sub-Hub and Single- Hub based IBAA modeling approaches can have some limitations with respect to modeling accuracy. Both approaches ignore the potential effects of unscheduled loops flows from both within the IBAA systems (base load schedules of internal IBAA generation on-line to serve native load) as well as from regional schedules/transactions. This includes the impact of schedules on the large non-ISO Controlled Grid portion of the California Oregon Transmission Project (COTP). The COTP Schedules are schedules that the ISO does not see (for purposes of running the ISO's markets) today but that we know have an impact on not only the COTP itself, but the balance of the California Oregon Intertie (COI), a large portion of which is part of the ISO Controlled Grid.
The ISO proposes to implement future enhancements to the IBAA methodology that would include a certain level/representation of IBAA internal schedules in the ISO's market models so that the ISO can capture the impact of internal IBAA flows on the ISO Controlled Grid.

2. Proposed IBAA Pricing Methodology

2.1 *Choice of Sub-Hub Based IBAA Pricing over Multiple-Hub Based Pricing*

The ISO originally proposed to establish discrete prices for each of six initially identified System Resources or Aggregated System Resources anticipated to support intertie transactions between the ISO and SMUD and TID IBAAs. This was referred to as "sub-system hub" pricing and would have established prices for the following Sub-Hubs: SMUD, Western, MID, Roseville, TID and Captain Jack. Both the CAISO MSC and the CAISO's outside expert consultant expressed concern that the Multiple or Sub-Hub based pricing methodology was subject to gaming concerns. Since the Multiple-Hub methodology was based on Market Participants identifying the resources supporting a given intertie transaction or set of transactions, both the MSC, DMM and the CAISO's consultant, Scott Harvey, stated that it would create strong incentives and rationale for market participants to specify schedules that would maximize their market revenues, i.e., buy low, sell high, and not reveal the true nature and location of the specific resources supporting the intertie transaction (information that is critical to the CAISO obtaining a reasonable approximation of the impact of such transactions on the CAISO Controlled Grid). Scott Harvey provided to stakeholders the experience of Eastern ISO's with gaming arising from multiple hubs. The MSC recommended that the ISO minimize or further confine the pricing options available to entities scheduling intertie transactions between the ISO and the proposed IBAAs.

Based on that feedback and in the absence of better information regarding the nature and location of the marginal resources supporting intertie transactions, the CAISO developed and is now proposing a single-hub IBAA pricing methodology. As outlined below, the Single-Hub methodology establishes a Default Pricing Rule that prices all imports to the CAISO from the IBAAs based on the price at the Captain Jack substation and all exports from the CAISO to the IBAA based on the price at the SMUD hub. The ISO believes that the proposed IBAA pricing methodology reflects an appropriate balance of accuracy (i.e., aligning prices with schedules and dispatch) and the need to mitigate opportunities for inappropriate market arbitrage between pricing points when such price differences do not reflect the true value of the resources supporting the scheduled intertie transactions for purposes of managing congestion on the ISO's system.

2.2 *Single Hub IBAA Pricing Methodology – Management Proposal*

The proposed Single Hub – as well as the earlier Multiple-Hub - IBAA pricing mechanism relies on "proxy bus" pricing of the individual interconnections with the IBAAs. The Single-Hub methodology immediately addresses the concerns raised by the MSC, DMM and external experts because it establishes a Default Pricing Rule that prices all imports to the CAISO from the IBAAs based on the price at the Captain Jack substation and all exports from the CAISO to the IBAA based on the price at the SMUD hub. The proposed Single Hub default pricing rule would apply in the absence of an alternative arrangement, which would enable that the ISO obtain more detailed information regarding the resources supporting the scheduled intertie transactions and there is a demonstrative benefit to the ISO Market of such an arrangement.

Proxy buses are used by the eastern regional transmission organizations (RTOs) and independent system operators (ISOs) to price intertie transactions.[12] Proxy bus pricing collapses some or all of the individual interconnection points with other BAAs into a single, combined bus with a weighted-average price. The use of proxy buses allows RTO/ISOs that have LMP based systems to manage a number of possible effects including the fact that entities can schedule intertie transactions at points that may be inconsistent with, or not accurately reflect, the actual dispatch and location of the resources used to implement the intertie transactions.

Based on the MSC's feedback, and as supported by the "proxy bus" experience of the Eastern RTOs/ISOs, the ISO is now proposing to consolidate the pricing points for intertie transactions between the ISO and the proposed IBAAs. In the absence of detailed information regarding the resources supporting scheduled intertie transactions, the ISO proposes to establish a new default Single Hub IBAA rule. Under this rule, all transactions between the ISO and the proposed IBAAs would be priced as a single hub, combining the SMUD, Western, MID, Roseville, TID, and Captain Jack subsystems, as follows:

1) All imports to the ISO from the proposed IBAAs would be priced based on the LMP at the Captain Jack proxy bus; and
2) All exports from the ISO to the proposed IBAAs would be prices based on the LMP at the SMUD hub.

The proposed default pricing rule is designed to minimize uncertainties for ISO Market Participants, i.e., those participants who would pay the costs should the ISO establish an IBAA pricing methodology that established inappropriate pricing incentives and resulted in uplift (redispatch) costs.

Management proposes that under this Single Hub pricing approach, the ISO may also agree to alternative settlement arrangements provided that the ISO is provided sufficient detailed information that either supports identification and verification of the marginal external resources supporting the applicable scheduled intertie transaction or otherwise supports ISO efforts to increase the accuracy of its congestion management solutions and a reasonable determination and cost-causation based allocation of ISO costs.[13] The ISO would enter into specific agreements to implement such alternative arrangements with IBAAs entities or other effected entities.

2.3 *Impact of IBAA Proposal on Non-ISO Controlled Grid Facilities*

---

[12] The PJM, NYISO, ISO-NE and MISO RTOs all use similar methods to model and price net interchange (imports and exports) with some or all adjacent dispatch regions.

[13] The ISO has developed an illustrative list of the type of information that may be provided to the ISO by the participants to support alternative settlement arrangements. Examples include: Scheduled flows by participant on COTP into SMUD/TID IBAA and associated e-tags; Scheduled flows between various sub-areas (hubs) within the SMUD/TID IBAA and associated e-tags if applicable; Disclosure of quantities of load served and generation resources controlled by Scheduling Coordinators scheduling imports/exports by location; Identifying the generators that provide the import to the ISO, which claim more granular pricing treatment; Identifying the loads that are the sinks for the export from the ISO, which claim more granular pricing treatment; Reporting of bilateral transactions including both sales and purchases (including options) using FERC EQR protocols; Providing other data available by SCs upon ISO request pursuant to ISO Market Monitoring authority; Integrated quantity of the schedule-deviation portion of the ACE (Area Control Error) of the SMUD control area (covering all its entities) over appropriate time intervals consistent with ISO markets.

It is important to note here that regardless of the pricing option, in no case is the ISO establishing prices for points outside of the ISO system. Rather, for deliveries (imports and exports) *scheduled* at the existing and *retained* ISO-IBAA Intertie Scheduling Points, the ISO is determining the price (value to the ISO for purposes of managing congestion and losses *on* the ISO Controlled Grid) for those scheduled transactions based on the price of the resources identified as supporting the transaction. While the identified resources may reside outside of the ISO Controlled Grid (e.g., are System Resources, as defined under the ISO Tariff), the price or value of that System Resource will be determined by a combination of its associated bid price and its location on the larger ISO-IBAA network (i.e., where it is injecting power) for purposes of managing congestion and calculating losses *only* on the ISO Controlled Grid. While certain stakeholders have raised concerns that under the IBAA pricing proposal the ISO would establish prices on facilities outside of ISO control, the ISO's proposal in fact is not proposing to price any facilities outside the ISO control. Just as it does today, the ISO would continue to price transactions at its interties, by establishing the rates, terms, and conditions of service over *only* the ISO Controlled Grid. External entities that operate under the traditional "contract path"[14] paradigm have raised concerns regarding the ISO's need to determine the point of injection (source) of a transaction – especially when that point is outside of the ISO Controlled Grid - for purposes of assessing the congestion impact of such an injection on the ISO Controlled Grid. However, the ISO has demonstrated that it is not pricing the external system under the IBAA proposal the ISO is only proposing to model the transactions at its IBAA ties such that price at its interties reflects the true cost of using its system for flows to and from such closely integrated systems.

3. <u>Impact of the IBAA Proposal on CRRs – Management Proposal</u>

In addition to using the FNM for scheduling power flows and determining locational energy prices in the core MRTU market systems, the ISO uses the FNM in the allocation and auction of CRRs. The CRR FNM includes the modeling of Existing Transmission Contracts (ETCs), which provide a "perfect hedge" against congestion costs associated with usage of ETC rights between the locations of the ETCs' sources and sinks, including sources and sinks in an IBAA. For other schedules, the allocation of CRRs provides an opportunity for Load Serving Entities (LSEs) and Out of Balancing Authority Area Load Serving Entities (OBAALSEs) to obtain CRRs to manage their congestion costs between locations within the ISO Controlled Grid from sources or to sinks in an IBAA. Accuracy of the FNM in the CRR process is critical to the ISO's ability to balance the competing objectives of releasing as many CRRs as possible to market participants, while minimizing the risk of CRR revenue shortfall that could occur if the ISO collects insufficient congestion revenues from the Day-Ahead Market to cover CRR settlements fully on a monthly basis.

During the stakeholder process on the IBAA modeling and pricing approaches, participants raised three primary issues regarding how the adoption of IBAAs may affect the release and settlement of CRRs. Each of those issues is discussed further below.

3.1 *Impact of an IBAA change (either the creation of a new IBAA or the modification of an existing IBAA) on the future release of CRRs*

In general, the ISO expects that IBAA changes will undergo extensive study and analysis before they are implemented in the FNM. The ISO will strive to synchronize future IBAA changes with the annual CRR release process. That is, the ISO intends to schedule new IBAA changes to take effect on January 1 of a new year (i.e., in the Day-Ahead Market that is run

---

[14] A "contract path" methodology assumes that power flows over designated transmission facilities between one point (point of receipt) and another (point of delivery) on a transmission system. The ISO's approved MRTU LMP based system does not assume that power flows over a pre-designated or identified path, but rather determines the impact of power flows over the entire network from injections at one point (source) and withdrawals at another (sink).

on December 31), and to provide to market participants all the IBAA modeling and pricing details as part of the FNM information package that is made available for CRR purposes prior to the conduct of the annual CRR release process for that year. As a result, all CRRs released – including one-year Seasonal CRRs as well as Long Term CRRs – would be released using the same basic FNM that will be used in the Day-Ahead and Real-Time markets when those CRRs become effective. In some instances there may be a need to implement an IBAA change mid-year because of a need for improved accuracy in the Day-Ahead and Real-Time Market congestion management processes. In such a case the ISO would incorporate the IBAA change into the FNM for the first monthly CRR process in which the IBAA change will take effect, and will follow the proposed provisions described below for assessing and mitigating impacts on the previously-released Seasonal CRRs for the remainder of that year.

3.2 *Impact of an IBAA change on the settlement of previously-released CRRs*

The term "previously-released CRRs" refers to those CRRs that were released based on a CRR FNM that did not include the IBAA change in question and that will continue to be in effect – either as active financial instruments or as allocated CRRs eligible for renewal nomination in the Priority Nomination Process (PNP) – when the IBAA change is implemented in the ISO spot markets. If the IBAA change is implemented to coincide with the beginning of a calendar year and is coordinated with the annual CRR release process for that year, as described in the previous sub-section, then the provisions discussed here would apply to previously-released LT-CRRs plus those previously-allocated Seasonal CRRs eligible for PNP nomination. Alternatively, if the IBAA change is implemented in the spot markets in mid year, then these provisions would apply also to any previously-released Seasonal CRRs still in effect, for the remainder of their term.
One concern that several stakeholders expressed relates to the potential for an IBAA change to create a discrepancy between the source or sink location of a previously-released CRR and the new source or sink that is adopted based on incorporating the IBAA transmission and pricing provisions into the FNM.

Based on feedback from stakeholders and the ISO's careful consideration, the ISO proposes an approach that would allow the holder of a previously-released CRR whose source or sink is affected by the IBAA change to make a one-time election either to (a) modify the settlement of the CRR to be congruent to the revised IFM pricing associated with the IBAA change, or (b) retain the original source or sink specification of the CRR., subject to the requirement that affected CRR Holders make their elections prior to the start of the ISO's process to release any new CRRs for the period when the IBAA change will be in effect. The ISO believes this approach is balanced, enables CRR Holders to maintain their intended hedge against potential congestion costs for purposes of serving load, yet allows those CRR Holders that procured a CRR for purely financial purposes to keep their original financial instruments.

The annual CRR allocation and auction process conducted in 2007 for the release of 2008 CRRs used the multiple-hub IBAA model described in section 1.2. Implementation of the single-hub model described in section 1.3 would entail a departure from the CRR FNM assumptions under which 2008 CRRs were released having sources or sinks within the IBAA. Thus under the Management proposal a holder of such affected CRRs would be given an opportunity to make a one-time election, for each affected CRR they hold, either to retain the IBAA source and sink specification as originally awarded, or to reconfigure the affected CRR source or sink to match the revised pricing locations of the single-hub IBAA approach. These provisions would apply to (a) Seasonal CRRs that are in effect during the months of 2008 for which the MRTU markets are operating, (b) previously-allocated Seasonal CRRs that are eligible for PNP nomination, and (c) previously-released Long Term CRRs.

3.3 *Impact of an IBAA change on the revenue adequacy of previously-released CRRs*

One consequence of modifying the sources or sinks of previously-released CRRs to match the new pricing locations associated with the IBAA change is that the entire set of previously-released CRRs may no longer be simultaneously feasible. Such a departure from simultaneous feasibility could increase the risk of – but would by no means definitively cause – a shortfall in the ISO's collection of the IFM congestion revenues used to settle with CRR Holders. Because the MRTU Tariff requires that all CRRs be fully funded, any revenue shortfall that results from IBAA-related changes to CRR sources and sinks would have to be funded somehow to prevent any direct impacts to the CRR Holders. The ISO proposes to use the CRR Balancing Account – which has already been approved by FERC as the means to ensure full funding of CRRs – to cover any IBAA-related shortfall that occurs in a given month. It is important to recognize that revenue inadequacy is not a problem if the IBAA change is incorporated consistently into the CRR network model that is used in the release of CRRs applicable to all time periods.

In the case of the proposed SMUD and TID IBAAs, the multiple-hub IBAA approach was incorporated into the CRR FNM for the annual CRR release processes (allocation and auction) that were conducted during 2007. Under the single-hub approach now proposed, the CRR reconfiguration policy discussed in the previous sub-section would now apply.

In cases where IBAA changes are implemented after some Seasonal and Long-Term CRRs have been released based on different FNM assumptions, the ISO would be able to test for any potential failure of simultaneous feasibility and, if it exists, to estimate its magnitude.

As noted above, the ISO proposes to use the CRR Balancing Account to cover any shortfall that occurs in any given month. There are several reasons why the ISO believes it is appropriate to use the CRR Balancing Account to manage this risk. First, the Tariff requires that all CRRs be fully funded, and FERC has approved the use of the CRR Balancing Account and associated allocation of any resulting shortfall to measured demand for ensuring full funding of CRRs. Second, because any given IBAA change will occur in a limited area of the grid, it can be expected to affect a relatively small share of the total released CRRs, and hence any impact on revenue adequacy should be small relative to the total volume of congestion revenues and CRR settlements. Third, although any particular IBAA change will typically occur in a specific area of the grid, the benefits of the IBAA change in terms of improved accuracy of congestion management and pricing will benefit users of the entire ISO BAA. Fourth, it will not be possible to specifically assign any net CRR revenue shortfall at the end of each month to the IBAA change in any reliable, non-arbitrary manner.

4. Process for establishing New, or Modifying Existing, IBAAs – Management Proposal

Finally, in response to stakeholder concerns, the ISO is also proposing a process for the adoption and implementation of additional IBAAs in the future (or a modification of then existing IBAAs). The proposed process requires the ISO to seek collaboration and conduct a consultative process with the affected BAAs and ISO stakeholders.[15] Specifically, the ISO is proposing to include in its Tariff provisions that, except under exigent circumstances, would require that the ISO follow a consultative process with the affected BAA and its stakeholders. As part of this process, the ISO will engage in direct discussions with the affected BAA and seek to develop modeling specifications that most accurately reflect the affected BAA. In addition, the ISO will be required to stakeholder the modeling and pricing of the new or changed IBAA and would also be required to seek ISO Board of Governors approval to the extent that implementation of the new or changed IBAA requires changes to the IBAA provisions already reflected in the Tariff and BPMs. Finally, the ISO would be required to make a FERC filing to modify its tariff to actually add a new IBAA or change any of the elements regarding the existing IBAA reflected in its Tariff. The ISO believes this consultative process with the appropriate ISO Board of Governors and

[15] The ISO proposes to include this process requirement in its tariff and provide further details of the actual procedures in the Business Practice Manuals for the Full Network Model.

FERC approvals provide market participants sufficient reassurance of process should any new IBAAs be adopted or existing ones change.

STAKEHOLDER PROCESS AND FEEDBACK

The ISO's IBAA proposal and related tariff changes are a result of a stakeholder process that included both consultation with the affected BAAs as well as a broader stakeholder discussion on the details and merits of the ISO proposal. **Attachment B** summarizes the salient aspects of the ISO's IBAA Stakeholder process and stakeholder comments submitted on April 28, 2008, on the major elements of the ISO's proposal. Management summarizes below the major issues raised by stakeholders with respect to each of the major elements of ISO's IBAA proposal and Management's response.

Stakeholder Comments on Process

Stakeholders have expressed significant concerns and frustrations over the ISO's process. The affected IBAA entities (SMUD, Western, MID, TID, City of Redding, Department of Energy National Labs, the Transmission Agency of Northern California, and the Transmission Agency Northern California) do not believe that the ISO afforded sufficient time to the ISO's bilateral discussions (consultation) with those entities and inappropriately stopped those discussions in the fall 2007. IBAA entities generally represent that the ISO should not implement the IBAA proposal unilaterally but should instead enter into mutually acceptable agreements with affected IBAAs. IBAA entities also state that the ISO has not responded to, or modified the ISO's proposal as a result of, stakeholder comments.

Management engaged in a consultation with the IBAA entities from approximately June 2007 though October 2007. At that time, based on IBAA entity opposition to the ISO's then-proposed IBAA proposal and because of the then-impending February 1, 2008, MRTU start date, Management determined that it was appropriate and prudent to initiate a broader stakeholder discussion and finalize the proposal prior to MRTU start up.

With respect to stakeholder comments that the ISO has not modified its proposal in response to stakeholder comments, Management notes that the ISO: 1) has deferred action (ISO Board of Governors approval and/or FERC filing) on the IBAA proposal three times in response to stakeholder concerns; 2) has agreed to file the pricing and other elements of the IBAA proposal at FERC; 3) developed and committed to a going-forward IBAA process (consultation, stakeholder, and FERC filing); 4) assessed and developed a proposal in response to stakeholder concerns regarding the impact of the IBAA proposal on CRRs; and 5) developed an alternative settlement treatment mechanism to address circumstances where the ISO is able to obtain more detailed information from IBAA entities.

Stakeholder Comments on IBAA Modeling

Stakeholders appear to support the ISO's objectives to increase the accuracy of the ISO's models and congestion management solutions. In large part because the ISO does not currently have access to certain information, certain stakeholders question whether the ISO's IBAA proposal will in fact result in improved congestion management solutions and less need to redispatch in real-time.

Management agrees that information on specific resource operation is the best way to improve the ISO's congestion management solutions, particularly with respect to the managing congestion on the ISO Controlled Grid arising from transactions with IBAAs, would increase with additional and better information from the IBAAs. Management's proposal allows for alternative settlement treatments if the IBAAs are able to provide more detailed information regarding the resources supporting certain intertie transactions with the CAISO. Notwithstanding the ISO's desire for more detailed information, Management believes the ISO's proposed IBAA modeling methodology is a reasonable and "best available" approach that will further increase the accuracy of the ISO's congestion management solutions.

Stakeholder Comments on IBAA Pricing

IBAA entities do not believe the ISO has justified its pricing proposal and that application of the IBAA pricing methodology to just SMUD/Western and TID – as opposed to all interconnected BAAs or none at all – is discriminatory. The affected IBAA entities also have raised concerns regarding potential adverse impacts on their own facilities. IBAA entities assert that the ISO's proposal will de-value their investments in their own systems. Specifically, TANC members represent that the ISO's proposal will de-value their investment in the COTP and upsets the balance of burdens and benefits negotiated as part of the Owners Coordinated Operating Agreement that governs coordinated operation of the COTP and the Pacific Ac Intertie.

Management believes that the proposed IBAA default pricing rule is appropriate and reasonably minimizes risks to ISO customers. Specifically, in the absence of additional information that identifies and validates the resources supporting specified intertie transactions and enables the ISO to increase the accuracy of its congestion management solutions, the proposed default pricing rule appropriately minimizes exposure to uplift costs likely to result from inaccurate pricing of IBAA transactions with the ISO. With respect to TANC member's concerns regarding the potential adverse impact of he IBAA pricing proposal on their investments, Management has demonstrated that the proposal does not price or value any external systems. Nonetheless, the Management has expressed a willingness to work with the TANC members to justify an alternative arrangement as described above in Section 2.2 that could provide the TANC members with a settlement treatment that could in their view better reflect and maintain the value in their investment.

Stakeholder Comments on CRRs

IBAA entities represent that the ISO did not adequately discuss or detail the proposed IBAA pricing structure and never informed the IBAA entities or any stakeholder of the IBAA pricing methodology prior to the start of ISO's initial MRTU CRR allocation and auction exercises in summer 2007. The IBAA entities assert that had they known the IBAA pricing approach was reflected in the ISO's CRR model, they may have requested a different set of CRRs.

Management believes that it has addressed stakeholder concerns regarding the impact of the IBAA proposal on the CRRs allocated and auctioned under last year's CRR process. As noted above, the ISO's proposal includes a process for making, if requested; appropriate adjustments to the configuration of CRRs allocated prior implementation of both the current and any future IBAA proposal. While the set of allocated CRRs impacted by the IBAA proposal is limited (as a result of the ISO's decision to defer the start date for MRTU to the Fall of 2008, the CRRs allocated and auctioned in 2007 will now only be effective for a 2-3 month period), the ISO nonetheless proposes that CRR holders have the option of making one-time adjustments to their CRRs to conform to the new IBAA pricing proposal.

MANAGEMENT RECOMMENDATION

Management recommends that, as described more fully above, the ISO Board of Governors approve: 1) the proposed adoption of the SMUD and TID IBAAs to commence at the start of MRTU; 2) the proposed Single-Hub IBAA pricing methodology; 3) the proposal for addressing CRR issues related to the IBAA proposal by enabling parties to opt for reconfiguration of previously releases CRRs; and 4) the process for creating new, or modifying existing, IBAAs. Management also recommends that the ISO Board of Governors authorize Management to make a filing at FERC to implement the ISO's proposals, effective upon the start-up of MRTU. In addition, Management recommends that the ISO Board of Governors approve that the ISO enter into alternative settlement arrangements with IBAA entities or other effected entities on a case-by-case basis where additional data is provided by the affected IBAA entity and there is a demonstrated benefit to the CAISO system for such alternative pricing arrangements. Finally, Management recommends that the ISO Board of Governors authorize Management to make any necessary filings at FERC to implement such alternative pricing arrangements.

The IBAA proposal is fully consistent and aligned with the overarching goals of the MRTU program. Specifically, the IBAA proposal is necessary to increase the accuracy of the ISO's congestion management processes. Improved modeling of the IBAAs will minimize potential discrepancies between: 1) modeled flows and congestion in the Day-Ahead Market, versus 2) actual flows and congestion in the Real-Time Market. These modeling improvements and the resulting reduction in Day-Ahead to Real-Time discrepancies will increase the accuracy and reliability of LMPs in reflecting actual system conditions, managing congestion, and generally promoting consistency between the spot markets and the operating needs of the grid. More importantly, the proposed pricing mechanisms will eliminate inappropriate arbitrage between pricing points. The ISO's proposal will also permit entities to obtain alternative pricing treatment, should they provide the ISO will more detailed information regarding the resources supporting identified interchange transactions.

Attachment A to the CAISO Board Memo was the Market Surveillance Committee's Opinion on IBAAs. However, the Market Surveillance Committee's Opinion has been set forth as a separate attachment to the instant filing, please see Attachment I of the filing materials.

Board of Governors 5/21-23/08 Decision on Integrated Balancing Authority Proposal

Moved: Capuano **Second: Gage**

Board Action: **Passed**	Vote Count: **5-0-0**
Capuano	Y
Doll	Y
Gage	Y
Page	Y
Willrich	Y

<u>Motion</u>

> **Moved, that the ISO Board of Governors approves the Integrated Balancing Authority Area (IBAA) proposal, as detailed in the memorandum, and related attachments, dated May 13, 2008, and**
>
> **Moved, that the ISO Board of Governors authorizes Management to make all of the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the IBAA proposal, and**
>
> **Moved, that the ISO Board of Governors authorizes Management to enter into alternative settlement arrangements as appropriate for intertie transactions between the ISO and IBAA entities or other affected entities based on the provision of additional resource specific detailed data and a demonstrated benefit to CAISO customers, and**
>
> **Moved, that the ISO Board of Governors authorizes Management to make all of the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement such agreements, if any.**

Motion Number: 2008-05-G4