UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER08-1113-000

EXECUTIVE SUMMARY OF

PANEL AFFIDAVIT OF

DOUG BOCCIGNONE, KEVIN WRIGHT, AND DR. PUSHKAR WAGLE

SVP's panel affidavit is submitted by Doug Boccignone, Kevin Wright, and Dr. Pushkar Wagle. Their affidavit identifies problems with the CAISO's modeling and pricing, establishes that pricing for COTP and Western resources should be at the Tracy interconnection, and they address substantial differences between the CAISO's proposal and the circumstances taking place on the Eastern RTOs.

The CAISO's IBAA proposal contains four primary problems: (1) the proposed approach to modeling and pricing IBAA imports at Captain Jack will harm the CAISO market as a whole; (2) the IBAA proposal will harm SVP as a COTP participant; (3) the IBAA proposal will harm SVP as a Western Area Power Administration ("Western") Base Resource customer; and (4) the CAISO's reliance on circumstances occurring in PJM does not support its proposal because the circumstances in northern California are materially different from those on PJM.

Locational Marginal Prices ("LMP") will be wrong under the CAISO's flawed modeling approach. The incorrect modeling will cause inaccurate Day Ahead approximations of the actual flows on the system. The result will be inefficient usage of the CAISO transmission system, potentially infeasible schedules due to failure to model the full system flows from the northwest, and increased costs for CAISO Market Participants based on the unnecessary uplift costs associated with redispatch. Solutions to the modeling problems are avoidable. To improve the CAISO's modeling and pricing, the CAISO should use available information to make realistic estimates of total COI flows by modeling approximations of all COTP schedules as being sourced at Captain Jack (even if not sinking in the CAISO), using a combination of historical COTP scheduling data, actual historical COI flow data, actual Malin schedules as a proxy for COTP schedules, and actual COTP schedules sinking in CAISO as a proxy for COTP schedules.

To avoid the unjust and unreasonable results, including violation of contracts, inherent in the CAISO's proposal, COTP imports to the CAISO must be settled at Tracy, rather than at Captain Jack. Settling at Tracy recognizes that the COTP provides reciprocal benefits and increases the transfer capability into northern California from the Pacific Northwest, avoids charging unscheduled flows, avoids duplicative congestion and loss charges, and is otherwise consistent with the CAISO's Tariff and COI obligations. In addition, pricing COTP at Tracy will allow the CAISO to earn sufficient revenues.

SVP's imports from the Western Base Resource to Tracy should be priced at Tracy for similar reasons as stated for COTP. Because the congestion and loss components of the LMP at Tracy are likely to be higher than those at Captain Jack, settling Tracy imports at the Captain Jack prices unnecessarily and inappropriately increases the cost to deliver Western resources to load within the CAISO BAA.

The panel demonstrates how the solutions developed by PJM to address its pricing issues do not support the CAISO's IBAA proposal. Unlike the situation in PJM, essentially all low-cost energy scheduled to be delivered into northern California over the COTP and PACI lines actually flows on these facilities to the locations where the energy is needed. Notably, PJM initially used electrically and technically-correct solutions. PJM only made less desirable changes after actual problems occurred, and only imposed them on interchanges where problems occurred. The panel concludes that the situation in northern California is distinctive from the situation in PJM, and that imposing the PJM solutions in northern California would be premature at best.

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Affiants, being duly sworn, state as follows:

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your names and business address.

A. Our names are Doug Boccignone, Kevin Wright, and Dr. Pushkar Wagle and we are employed by Flynn Resource Consultants Inc. Our business address is 5440 Edgeview Drive, Discovery Bay, California 94505.

Q. On whose behalf are you submitting this affidavit?

A. We have been retained by the City of Santa Clara, California ("Santa Clara"), doing business as Silicon Valley Power ("SVP"), to review the California Independent System Operator Corporation's ("CAISO") Integrated Balance Authority Area ("IBAA") proposal.

Q. Mr. Boccignone, please describe your qualifications.

A. I am a registered professional electrical engineer in the State of California. I hold a B.S. in Industrial Engineering and Engineering Management from Stanford

University and a B.A. from Claremont McKenna College in Management-Engineering, with high honors. I have over 20 years of experience working for and consulting to utilities, generators and marketers. The bulk of my experience is in the California market, before, during and after the transition to the CAISO. I am presently a principal at Flynn Resource Consultants Inc., where I provide strategic advice on complex energy-related business issues to municipal utilities and independent power producers. Much of my work involves evaluating CAISO protocols and market rules and their impacts on municipal utilities.

Q. Have you previously provided testimony to this Commission or the California Public Utilities Commission?

A. Yes. I provided direct and answering testimony to the Commission in the Pacific Gas & Electric Company Scheduling Coordinator Services Tariff proceeding, FERC Docket Nos. ER00-565-000, ER00-565-007. I also have provided testimony to the California Public Utilities Commission in San Diego Gas & Electric's Valley-Rainbow transmission project proceeding.

Q. Mr. Wright, please describe your qualifications.

A. I am a registered Professional Engineer in the States of Pennsylvania and New Jersey. I hold a B.S. in Electrical Engineering from Lafayette College in Easton PA and I earned an MBA in Finance from St. Joseph's University in Philadelphia PA. I worked for thirty-one years for GPU, which was later acquired by First Energy Corporation. I worked from 1971 - 1989 as an engineer, supervisor, and manager in the Transmission Planning Department of GPU Service Corporation and from 1989 – 1992 as Manager of System Operations. I became Director of System Operations at Jersey Central Power and Light Company, one of the operating subsidiaries of GPU, in 1992. I returned to GPU Service Corporation in 1996 as Director of Energy Management and later Director of Supply Portfolio Management. I continued to work in this position until the end of 2001 when First Energy and GPU merged. I left First Energy in mid-2002 after serving as Interim Director - Enterprise Risk Manager. I served on the PJM Capacity and Transmission Planning Subcommittee for approximately seven years, during which time I also served on both MAAC – ECAR - NPCC (MEN) Committees and VACAR – ECAR – MAAC (MEN) Committees. I served on the PJM System Operating Subcommittee for approximately five years. After leaving First Energy I worked for approximately one year for Morgan Stanley as a Financial Advisor before returning to the electric utility industry. I worked for three months with the Midwest ISO. I then began working for the Imperial Irrigation District (IID) in December of 2004. I served as Director of Supply and Trading leading both their energy scheduling, energy billing, and energy risk management functions. In May 2006 I began working for the Massachusetts Municipal Wholesale Electric Company (MMWEC) as Director of Supply and Trading. There I led their energy scheduling, energy billing and energy risk management functions. I retired from MMWEC in November 2007. I am presently employed as a Senior Consultant with Flynn Resource Consultants Inc.

Q. Have you previously provided testimony to this Commission?

A. No.

Q. Dr. Wagle, please describe your qualifications.

A. I have over 10 years of experience in the electric utility industry. I have worked in the areas of renewable energy planning, economic valuation of electricity transmission projects, market simulations modeling, electricity market design, electricity market price forecasting, electricity generating asset valuations, optimization of energy resource portfolio and risk management. I also provide strategic advice on energy-related management issues to several electric companies. I have published in the areas of electricity generation and transmission adequacy, transmission investment alternatives, ancillary service markets and market-based valuation of coal technologies. I have a B.S. in Mathematics and a Masters in Economics from the University of Bombay, India and a Ph.D. in Economics from the Stony Brook University.

Q. Have you previously provided testimony to this Commission?

A. No.

II. PURPOSE

Q. What is the purpose of your Panel Affidavit?

A. The purpose of our Panel Affidavit is to demonstrate that the approach taken in the CAISO's June 17, 2008 Integrated Balancing Authority Area (IBAA) proposal will cause harm to the CAISO market, harm to SVP as an entity with an allocation of rights on the California-Oregon Transmission Project (COTP) and harm to SVP as a Western Area Power Administration (Western) base resource customer. We also demonstrate that the circumstances in northern California are different from those that motivated PJM Interconnection (PJM) to implement single hub pricing for imports to PJM from the south and west. We address the CAISO's "counterproposal" and describe an alternative approach that should be taken to avoid the harm that would be caused by CAISO's IBAA proposal, for the benefit of all CAISO Market Participants. Specifically,

a. The CAISO must include in its Day Ahead and real-time market models realistic estimates of total energy flows on the COI, including those related to transactions that are not scheduled in the CAISO markets. COTP imports should be modeled as sourced in the Northwest (Captain Jack) and COTP exports should be modeled as sinking in the Northwest (Captain Jack).

b. COTP imports and exports should be priced at their intertie scheduling point (Tracy). Scheduling point pricing could be accomplished by the CAISO providing a credit for any losses and congestion charges between Captain Jack and Tracy, recognizing that:

- the COTP Participants invested hundreds of millions of dollars to build transmission that increased reliability and access to low-cost energy; and
- the COTP provides reciprocal benefits to the CAISO, including support for parallel flows and recovery of the associated congestion costs and losses; and
- the CAISO will fully recover the congestion costs and losses it actually incurs by applying correct prices at Malin to the schedules at Malin.

c. The crediting mechanism can be linked only to the amount of a party's rights to COTP capacity (*e.g.*, it cannot be reduced for any load served by existing contracts, internal generation or CAISO resources, or for any third party purchases or sales).

d. Transactions with Western should be priced at the intertie scheduling point (*e.g.*, Tracy).

e. The CAISO cannot require data from an entity that is not within that entity's control, and the CAISO must limit the data it seeks to a realistic scope, with protections for the BAA entities with respect to the use of that data.

f. The CAISO should include the effect of losses on external transmission facilities modeled in its FNM and state estimator in its LMP calculations.

Q. Please describe the problems created by the CAISO's proposed approach to modeling and pricing IBAA transactions, including those using the COTP.

A. The CAISO's proposed approach to modeling and pricing IBAA imports at Captain Jack will harm the CAISO market as a whole, it will harm SVP, as an entity with an allocation of rights on the COTP, and it will harm SVP as a Western Base Resource customer.

III. <u>HARM TO THE CAISO MARKET</u>

Q. How will the CAISO's proposed approach harm the CAISO market as whole?

A. The CAISO's proposed modeling approach will not lead to realistic Day Ahead approximations of the actual flows on the system. The Locational Marginal Prices (LMPs) created by the modeled injections and withdrawals will therefore be similarly incorrect, so the prices paid by consumers and received by suppliers in the Day Ahead market will be incorrect. The result will be inefficient usage of the CAISO transmission system, potentially infeasible schedules due to failure to model the full system flows from the Northwest, and CAISO Market Participants will bear the burden of resultant real-time redispatch costs that will create unnecessary uplift costs.

Q. Please explain why the LMPs will be incorrect.

A. By modeling only IBAA imports scheduled to the CAISO, rather than at least including an approximation of all expected flows over the COTP, CAISO's LMPs will not correctly reflect the value of incremental injections or withdrawals within, to or from the CAISO Balancing Authority Area. Approximately 75% of the ownership entitlements to COTP transfer capability are controlled by entities whose load is outside of the CAISO BAA ("IBAA COTP Rights"). Because those rights enable those entities to access low-cost resources from the Pacific Northwest, it is reasonable to assume they will use those rights to deliver that energy to their native load whenever possible. In a typical heavy load hour, the IBAA COTP Rights would be used to deliver more than 1,100 MW of the 1,500 MW of COTP available transfer capability to IBAA load. During these same hours, the CAISO is likely to be exporting to the IBAA Entities, rather than importing from the IBAA. Thus, at best, CAISO would see approximately 400 MW of COTP imports scheduled at Tracy by the COTP Participants to supply their load within the CAISO BAA. If the CAISO models only 400 MW of COTP imports (injected at Captain Jack), the modeled flows on the CAISO system will be significantly understated since it will only reflect the unscheduled flow on PACI from the COTP schedules at Tracy and will not reflect the unscheduled flow from COTP schedules sinking in the IBAA. This flawed modeling will result in incorrect Day Ahead LMPs and could result in infeasible schedules being allowed in the CAISO Day Ahead market, requiring redispatch in real-time.

The key objective of LMPs is to send a marginal pricing signal at each location to obtain an efficient dispatch and thereby obtain the most efficient use of the transmission system. Modeling assumptions that are inconsistent with realistic expectations of actual flows can lead to distorted prices and potentially thwart the objective of obtaining an efficient dispatch. The CAISO's IBAA proposal is structured in a manner that will not lead to a realistic representation of actual flows and, consequently, will result in incorrect LMPs.

Q. Can you provide an example to illustrate why the CAISO's IBAA proposal will not lead to a realistic representation of actual flows and will produce incorrect prices?

A. Yes. We modified the simplified 12-bus model of the CAISO and IBAA system developed by CAISO and posted on their website at http://www.caiso.com/1fab/1fab9f5167a60ex.html. Results of the model runs are attached as Appendix A. The model input assumptions are attached as Appendix B. The CAISO used this model to illustrate the effect on CAISO LMPs of scheduling limit congestion at Malin and of losses and flow limit congestion on the CAISO grid south of Malin.

Q. Did you make any changes to the assumptions in the CAISO's model?

A. Yes. The CAISO's model produced flows on the PACI and COTP facilities that are inconsistent with the flows shown in WECC operating and planning cases, and are likewise inconsistent with our understanding of actual observed flows. Specifically, because the COTP was designed with series compensation to reduce the reactance of the lines, a disproportionate share of the flow over the COI travels on the COTP. Thus, instead of two-thirds of the flow occurring on the

PACI and one-third of the flow occurring on the COTP, approximately 64% of the flow is on the PACI and 36% of the flow is on COTP. This results in higher real power losses on the COTP than would occur if the flows were exactly proportional to the contractual split. The simplified 12-bus model developed by CAISO did not capture this accurately. Therefore, to produce modeled results that are consistent with the design of the 500 kV system, we modified the reactance of the COTP lines in the 12-bus model. We did not otherwise alter the CAISO's assumptions about the system characteristics in the base 12-bus model, nor did we alter any of the resource bid curves. We did, however, test the effect of changing assumptions about the amount of generation modeled at the Captain Jack substation, the amount of load modeled in the IBAA, and the effect of modeling real power losses within the IBAA.[1]

Q. Are there limitations to using a simplified representation of the CAISO and IBAA systems?

A. Yes. The CAISO's 12-bus model is a simplified representation of a large, complex system. It is very useful for illustrating how changes to key input assumptions affect the relative magnitude and direction of flows and prices. However, because it models a limited number of resources and loads, the price

[1] In the CAISO's base 12-bus model the resistive component of losses for COTP and the IBAA were set to zero. In the case in which we modeled resistance on the COTP, we used a lower value for the resistance of the Captain Jack to Olinda line than the value implied by the losses shown on slide 11 of the CAISO's April 3, 2008 Modeling and Pricing of Integrated Balancing Authority Areas (IBAA) presentation, because the implied value in the presentation was too high.

changes modeled may be more dramatic than one would observe if hundreds of resources and load nodes were modeled. Still, just as the CAISO was comfortable using the model to illustrate for stakeholders the potential impacts of the CAISO's IBAA proposal, we are comfortable that it is a useful tool to illustrate potential advantages and disadvantages to different modeling approaches.

Q. What were the results of running the model?

A. The figure in Appendix A, Base Case reflects base case assumptions about transactions at Malin of 3,000 MW and at Captain Jack of 1,500 MW[2] and IBAA load totaling 3,300 MW and IBAA resources totaling 1,500 MW. The resultant flows and prices can be considered to be representative of the actual flows and prices that would result if the CAISO modeled all IBAA loads and resources.[3] This is representative of the CAISO's original preferred approach to modeling IBAAs. In the Base Case, there are no binding transmission constraints (*i.e.*, there is no congestion), so any price differences are solely due to differences in the loss component of the LMPs at each node.

[2] These are lower than the combined Path Rating of 4,800 MW, due to an assumed seasonal reduction in transfer capability.

[3] Note that the CAISO 12-bus base case model did not include the resistance for the IBAA and COTP facilities. We did not change this assumption here, but including the resistance would change the modeled losses and prices, as we discuss later.

Q. How do these modeled flows and prices compare to the flows and prices that would be modeled by CAISO under its current IBAA proposal?

A. Under the current IBAA proposal, CAISO would model only IBAA imports or exports in its Day Ahead market that are scheduled into or out of the CAISO from the IBAAs. It would model all CAISO imports from the IBAA as being sourced at Captain Jack, including imports using the COTP. Appendix A, Case 1 reflects 400 MW of COTP Tracy imports, modeled as Captain Jack injections. The net IBAA load of 700 MW[4] would be served by IBAA exports from the CAISO. The LMPs in this scenario (Appendix A, Case 1) are approximately 12% lower than the LMPs in the Base Case (Appendix A, Base Case), because this model excludes 1,100 MW of IBAA load and 1,100 MW of imports over COTP to serve that IBAA load. Failing to model the COTP flows to serve IBAA loads in the Central Valley understates the amount of energy needed to serve the combined CAISO and IBAA loads by understating the total PACI plus COTP losses. In this simplified model of the CAISO's IBAA proposal, the understated losses puts a lower-cost generator on the margin, thereby lowering the LMPs throughout the system, including at Malin and Captain Jack[5].

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4 Net IBAA load is equal to 3300 MW total IBAA load less 1500 MW IBAA generation less 1100 MW COTP delivery = 700 MW net IBAA load. The net IBAA load is spread across the IBAA load nodes in proportion to the amount of load at each node in the Base Case. This approach is slightly different from the CAISO proposed approach, but is necessary since the simplified model does not include all of the nodes reflected in the CAISO proposal.

5 Since there is no congestion, the prices at all nodes are driven by the marginal unit for the system. Price differences across nodes are due solely to differences in the marginal loss components of the LMPs.

Q. What are the potential ramifications from the prices resulting from CAISO's failure to make realistic estimates of the full California Oregon Intertie (COI) flows?

A. By failing to make realistic estimates of the full COI flows, the CAISO's Full Network Model (FNM) will produce incorrect price signals and will dispatch resources in a manner that will result in inefficient usage of the CAISO transmission system, potentially infeasible schedules due to failure to model in the Day Ahead FNM the full system flows from the Northwest, and CAISO Market Participants will bear the burden of resultant real-time redispatch costs and associated uplift charges. The price signals will be incorrect because the modeled flows from the Northwest using the PACI and COTP will be understated, resulting in an understatement of the marginal loss impacts of those flows and an understatement of the need for resources within California. Because of these modeling problems, CAISO may dispatch resources in the Day Ahead market that cannot feasibly be delivered to load in real-time, which would require real-time redispatch and resultant market uplift costs.[6] If the Day Ahead prices are consistently lower than the real-time prices, as illustrated by the lower prices in

6 CAISO witness Dr. Harvey described this problem well in his affidavit: "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. [ISO-3 at 19].

Appendix A, Case 1 as compared to Appendix A, Base Case, suppliers that are not obligated to offer in the CAISO's Day Ahead market will have an incentive to offer in the real-time market instead. For example, Northwest suppliers may prefer not to sell at the lower Day Ahead prices. This would lead to more in-State generation being dispatched Day Ahead, driving up costs to consumers, since these resources would not have been as efficient as importing the lower-cost Northwest power.[7] In this scenario, in real-time some of the previously dispatched in-State generation will be paid to back down in favor of importing the lower-cost Northwest generation offered in real-time. This scenario is clearly undesirable from an economic efficiency standpoint, and is unnecessary from a practical standpoint, since CAISO can prevent it by making realistic estimates of total COTP usage.

Q. Is the CAISO aware that its failure to model COTP transactions that are directly scheduled with the CAISO will affect its LMPs and will require compensating injections in real-time to correct its modeling errors?

A. Yes. In CAISO's responses to stakeholder IBAA questions, the CAISO indicated that, although it had access to information about COTP schedules and actual flows, it would not model transactions not scheduled in the CAISO system. It would instead rely on compensating injections in real-time.[8] As CAISO earlier

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7 If it were more efficient to use the in-State resources, those resources would have been dispatched ahead of the imports, which Appendix A, Base Case shows did not happen.

8 Will the CAISO model COTP scheduled flows that are not scheduled as Imports to the CAISO and

Continued ...

acknowledged,[9] these compensating injections will affect the CAISO's real-time LMPs. The corollary to this effect is that the failure to include compensating injections in the CAISO's Day Ahead FNM will affect the Day Ahead LMPs.

Q. How could the CAISO improve its modeling to achieve a result closer to the Base Case without having access to the detailed information included in the Base Case model?

COTP actual flows (to improve the FNM solution within the CAISO)? If so, please explain how the CAISO intends to do so (*e.g.*, timing and source(s) of information)?]

> CAISO Response
> For transactions that are not scheduled into the CAISO system, the CAISO will not receive market nor any other information regarding the use of the COTP and thus will not model such schedules in its market systems and applications. The CAISO will receive non-CAISO Controlled Grid COTP aggregate net schedules in its role as Path Operator for the California-Oregon Intertie (COI), but that information will not be input to or used by the CAISO market systems/applications. In the real-time Market (RTM), the CAISO's market software will observe physical flows at the CAISO's boundary with IBAAs, based on the CAISO's telemetry, and determine sources of injections within the IBAAs and at Captain Jack that produce flows in the CAISO's power flow calculations that match the observed physical flows. For each subsequent interval of the real-time Dispatch, the CAISO's market software will assume that the difference between the calculated injections and the market schedules (*i.e.*, compensating injections) will continue at the most recently observed level. This process is necessary to maintain accurate congestion management as part of the CAISO's maintenance of system reliability. Although the compensating injections will affect LMPs (since they affect the flows on the CAISO Controlled Grid), there are no settlements for these compensating injections since that have not been scheduled into the CAISO's markets.

[CAISO Response to SVP Follow Up Questions to Joint SVP/SMUD/TID IBAA Questions submitted on February 29, 2008].

[9] LMPs would be adversely affected if the CAISO failed to calculate these compensating injections and therefore did not reflect actual, physical conditions in RT congestion management. [CAISO Response to Questions, Integrated Balancing Authority Areas (IBAA) February 15, 2008].

A. The CAISO could use available information to make realistic estimates of total COI flows by modeling at Captain Jack approximations of all COTP schedules (including those not sinking in CAISO). Specifically, if CAISO can not obtain actual scheduling data from COTP Participants in time for inclusion in its markets, the CAISO could make reasonable estimates using: (1) historical COTP scheduling data, to the extent available, and actual historical COI flow data; and (2) actual Malin schedules as a proxy for COTP schedules (*e.g.*, assume total Captain Jack schedules are equal to 50% of total Malin schedules); or (3) actual COTP schedules sinking in CAISO as a proxy for COTP schedules, adjusting for the COTP ownership share represented by those schedules.

Q. Why should the CAISO include realistic estimates of total COTP transactions at Captain Jack?

A. Unless the CAISO includes realistic estimates of total COTP transactions at Captain Jack, whether or not those transactions are scheduled with CAISO, the LMPs on, and at the interfaces to, its system will be incorrect, based on the inaccurate flows over the PACI that would be modeled in the Integrated Forward Market (IFM). The IFM would thus produce an inefficient dispatch, leading to increased costs to consumers, market uplifts and potential market disruptions, including potentially reduced levels of reliability. For these reasons, it is imperative that CAISO use the information available to it to include realistic estimates of the COTP transactions that are not scheduled into its markets. While the CAISO might be reluctant to make such estimates, it is important to recognize that choosing to not model transactions unless they are scheduled with the CAISO, is, in fact, making an estimate of zero megawatts for such transactions, which is likely to be the worst possible estimate and which will almost never be correct.

Q. Did you model a more realistic estimate of total COTP transactions in the simplified 12-bus example, but with less detail than the CAISO originally was seeking from the neighboring BAAs?

A. Yes. Appendix A, Case 2 reflects 1,500 MW of transactions at Captain Jack, consistent with the Base Case, and 1,800 MW[10] of IBAA load net of internal IBAA generation. The key difference of this modeling approach as compared to the CAISO's proposed approach as represented by Appendix A, Case 1, is that this case includes an additional 1100 MW of IBAA load along with an additional 1100 MW of resource modeled at Captain Jack. The prices in this case are essentially the same as in the Base Case. This result occurs even though this model nets internal IBAA generation against the internal IBAA load, instead of modeling the full IBAA loads and resources as in the Base Case. The greatest change in LMPs at any node in this case as compared to the Base Case is approximately 0.3%.

[10] 700 MW served by IBAA exports from CAISO and 1100 MW of IBAA load served by COTP transactions.

Q. Do you believe that the approach represented in Appendix A, Case 2 is a reasonable approach to modeling IBAA and COTP transactions?

A. Yes. By modeling the total COTP imports, including both CAISO and IBAA imports, and including the IBAA loads served by those imports, the resultant flows and LMPs are much more consistent with the LMPs that would be produced with the more detailed modeling approach reflected in the Base Case. This approach reflects a reasonable balance between the desire for modeling accuracy and the fact that the CAISO might not have complete access to IBAA load or resource information. The CAISO will have access to both COTP and IBAA imports or exports scheduled with the CAISO. By using information readily available to the CAISO and making realistic estimates, the CAISO can improve the accuracy of the prices over those that would result if the CAISO only included information from transactions that were scheduled with the CAISO.

Q. If the CAISO includes realistic estimates of the total COTP transactions at Captain Jack, would there still be harm to CAISO Market Participants if CAISO prices COTP imports at Captain Jack, rather than at Tracy?

A. Yes. If CAISO prices COTP imports at Captain Jack rather than at Tracy, the additional congestion charges and losses (the difference between the Tracy LMP and the Captain Jack LMP) will make some COTP imports that otherwise would have been economic become uneconomic.

For hours in which the Captain Jack-Tracy congestion charges and losses exceed the Captain Jack scheduling limit congestion value, CAISO faces two possible scenarios:

1. One possibility is that the COTP transmission which has been made uneconomic to schedule into the CAISO due to CAISO's flawed IBAA pricing will be scheduled to serve IBAA load, rather than CAISO load. This action will benefit the IBAA loads, at the expense of SVP and other CAISO Market Participants. CAISO will see the same flows and prices on its system that it would have seen had SVP scheduled the energy over COTP into the CAISO. PG&E, as the Participating Transmission Owner, will lose Wheeling Access Charge revenues if the COTP energy displaces exports from the CAISO to the IBAA, and the CAISO will lose Grid Management Charges associated with those foregone exports. The load within the CAISO that previously had been served by the COTP imports would now be served by the resources that previously had been exported to the IBAA. In this scenario, the overall CAISO dispatch would be unchanged from what it would have been had the COTP been used to import the energy to load within the CAISO. Except for the lost Wheeling Access Charges and Grid Management Charges, the CAISO's net revenues would be the same as they would have been had the CAISO settled the COTP imports at the Tracy price. SVP and others in the CAISO that would have utilized the COTP to bring

lower-cost energy to their customers would have to replace those low-cost imports with higher-cost CAISO energy that would have been exported to the IBAA.

2. The other, more troubling, possibility is that the low-cost energy from the Northwest will not be imported to either the CAISO or the IBAA, and therefore will need to be replaced by even higher-cost resources within the CAISO that would not otherwise have been dispatched. This inefficient dispatch of higher-cost resources will increase costs to all CAISO consumers. So, by attempting to assess charges on COTP imports that CAISO mistakenly believes to be necessary to avoid what it considers to be uplift of the Captain Jack vs. Tracy congestion and losses on 400 MW, all CAISO loads will directly incur higher dispatch cost.

In Appendix A, Case 3 shows that when internal generation is needed to replace the 400 MW of low-cost Northwest imports that are made uneconomic by the duplicative CAISO congestion and loss charges, the LMPs within the CAISO would rise approximately 25% as compared to Appendix A,Case 2. This increased cost would be borne by CAISO load and exports. In the example, all CAISO load would incur an additional cost of approximately $20/MWh, so that the CAISO could avoid what it incorrectly believes to be an uplift of approximately $2/MWh on 400 MW of COTP imports.[11]

Even if the price increase is not as dramatic when all the CAISO loads, resources and transmission facilities are modeled as compared to the simplified 12-bus model, it would take only a small increase in overall CAISO prices resulting from the loss of low-cost Northwest imports to overwhelm the Captain Jack vs. Tracy congestion and loss differential. Given the large amount of CAISO load relative to the small amount of COTP imports, the CAISO is risking subjecting its customers to potentially significant increased costs in hopes of recovering a small amount of COTP congestion and loss charges. For example, assume there is 40,000 MW of CAISO load and 400 MW of COTP imports would have been made to the CAISO absent the imposition of $4/MWh in additional COTP congestion charges and losses due to Captain Jack pricing (which would have resulted in an additional $1,600 in charges). CAISO prices would have to increase only slightly more than $0.04/MWh for CAISO consumers to be worse off than they would have been had CAISO settled the COTP imports at Tracy.

[11] The CAISO apparently believes the difference between the Tracy and Captain Jack LMPs would constitute an uplift if COTP transactions were settled at Tracy.

Q. Do you agree that if the CAISO settles COTP transactions at Tracy, the congestion and loss differential between Captain Jack and Tracy would result in a cost shift to CAISO customers from COTP Participants?

A. No. As described further in the next section, if the CAISO includes realistic estimates of the total COTP transactions in the FNM, the CAISO's settlements for the Malin schedules will fully reflect the impact of the contribution of the Malin schedules on the CAISO's share of the COI. If the CAISO were to settle COTP schedules at the Captain Jack price, the CAISO would be assessing congestion and loss charges between Captain Jack and Tracy on the Tracy COTP imports for which it already would have recovered the costs from the Malin schedules. If the CAISO is allowed to settle Tracy COTP imports at Captain Jack, the CAISO will have imposed congestion costs and losses onto the COTP imports that the CAISO has not incurred.

IV. <u>HARM TO SVP AS A COTP PARTICIPANT</u>

Q. If the CAISO includes realistic estimates of the total COTP transactions at Captain Jack, would there still be harm to SVP if CAISO prices COTP imports at Captain Jack, rather than at Tracy?

A. Yes. SVP already incurs the costs of transmitting energy within Western's sub-BAA on the COTP between Captain Jack and Tracy. The CAISO will recover the total congestion costs and losses associated with its share of the flows over the COI from the CAISO schedules at Malin. If CAISO also recovers congestion and loss charges between Captain Jack and Tracy for the COTP schedules, this over collection of congestion and loss charges will have a very real and negative effect on SVP. As Mr. Hance describes at SVP-1 at 6, if the average congestion and loss differential is $4/MWh as suggested by the CAISO at ISO-1 at 27, SVP would incur an additional $9.8 million in charges annually.

Q. Why should COTP transactions with the CAISO be settled at Tracy, rather than Captain Jack?

A. COTP transactions with the CAISO should be settled at Tracy, rather than Captain Jack, for several reasons. First, COTP Participants spent approximately $450 million to build the line, thereby increasing the transfer capability into northern California from the Pacific Northwest by 1600 MW or 50%, which increased the reliability of supply into northern California. This project created firm, physical transmission facilities and is not merely a "contract path" reflecting some theoretical amount of energy that can be delivered. The COTP and the PACI underwent an extensive path rating process, following stringent WECC transmission planning criteria, resulting in a combined north – south path rating of 4,800 MW.

Second, the COTP Participants bear the congestion costs and losses of the PACI unscheduled flows on the COTP by contract. CAISO is not charged for creating those impacts and, under the same contractual provisions, cannot charge the COTP Participants for the congestion costs and losses of the COTP unscheduled flow on the PACI.

Q. The CAISO argues that it is not charging for unscheduled or parallel flows on its system, and is only charging for scheduled flows.[12] Do you agree with that assertion?

A. No. By applying Captain Jack prices to COTP imports that are scheduled at Tracy, CAISO is charging for parallel flows from COTP schedules between the BPA BAA and the SMUD/Western BAA.

Q. Please explain.

A. COTP scheduled flows from the BPA BAA at Captain Jack to the SMUD/Western BAA creates parallel flows on the PACI. These transactions are not scheduled flows on PACI. The scheduled flows for COTP imports from the SMUD/Western BAA to the CAISO BAA are from Tracy to load within the CAISO BAA. It is not possible for COTP imports from the BPA BAA to be scheduled on the PACI. COTP imports from the BPA BAA can only be scheduled into the SMUD/Western BAA at Captain Jack onto the COTP. The CAISO is conflating a schedule on its system at Tracy with the schedules between the BPA BAA and the SMUD/Western BAA at Captain Jack. By confusing the parallel flow on its system resulting from a schedule on another system (SMUD/Western BAA), with the actual flow resulting from a schedule on its

12 "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." [ISO-1 at 68].

system, CAISO is attempting to create a mechanism by which it may create charges for parallel flow.

Q. Is the CAISO's treatment of losses on its system symmetrical with the SMUD/Western treatment of losses on its system, as claimed by CAISO at ISO-1 p. 78?

A. No, it is not. CAISO would charge Captain Jack to CAISO losses for a transaction sourced in the Northwest, in addition to the COTP losses Western charges for transactions on COTP between Captain Jack and Tracy. There is a clear duplicative charge for the losses between Captain Jack and Tracy (once by Western and once by CAISO). In contrast, Western would charge only Tracy to Western losses for a transaction sourced in the Northwest via PACI. The Western loss charges would be in addition to the Malin – Tracy losses charged by CAISO, but Western would not assess any charges for the losses on its system between Captain Jack and Tracy that result from the parallel flow associated with the Malin to Tracy import on the CAISO system. In this case, there is no duplicative charge for losses between Malin and Tracy. The only symmetry is that both Western and CAISO choose how to collect for losses. But the CAISO approach results in the CAISO recovering the cost of the same losses on its system twice: once from the Malin schedules, assuming it models full COI flows (which it must do to avoid "wrong" pricing on its system), and once from the Captain Jack schedules (which reflect the parallel flow losses on the CAISO grid between Malin/Captain Jack and CAISO load). As Mr. Hance explains in SVP-1 at 11-14, this duplicative collection of COTP losses has never before been applied, despite several significant changes in market structure and BAA relationship.

Q. Are there other reasons why COTP transactions with CAISO should be priced at Tracy, rather than Captain Jack?

A. Yes. Because the COTP facilities are highly integrated with the CAISO transmission facilities, the COTP provides significant reciprocal benefits to the CAISO. The COTP enables the COI to be operated more reliably than the two-line PACI system previously could be operated. Further, approximately one-third of the energy that is scheduled at Malin to use the PACI actually flows over the COTP. Similarly, approximately two-thirds of the energy that is scheduled into the SMUD BAA at Captain Jack flows over the PACI. Because the PACI has approximately twice the capability of the COTP, this means that two-thirds of the energy flows and losses on the COTP are actually associated with PACI schedules. Table 1 shows that the unscheduled flows and associated losses on COTP are equal to the unscheduled flows and associated losses on PACI. The CAISO incurs the costs of all of the congestion and losses on the PACI, whether they are from the scheduled usage of the PACI at Malin, or from the unscheduled usage of the PACI from schedules into the SMUD/Western BAA at Captain Jack. Likewise, SMUD/Western incurs the costs of all of the congestion and losses on the COTP, whether they are from the scheduled usage of the COTP into SMUD/Western at Captain Jack, or from the unscheduled usage of the COTP from schedules into the CAISO BAA at Malin.

Table 1: Path 66 Losses at 4500 MW Flow			
CAISO			
Category/Source	PACI Losses (Malin scheduled flow)	PACI Losses (Unscheduled flow from COTP)	PACI Losses (Total)
Actual Loss (%)	4.0%	4.0%	4.0%
Actual Loss to Tesla/Tracy (MW)	80.0	40.0	120.0
Western			
	COTP Losses (COTP Scheduled Flow)	COTP Losses (Unscheduled flow from Malin)	COTP Losses (Total)
Actual Loss (%)	4.0%	4.0%	4.0%
Actual Loss to Tesla/Tracy (MW)	20.0	40.0	60.0

Q. If COTP transactions with the CAISO are priced at Tracy, rather than Captain Jack, will CAISO recover sufficient revenues to cover the congestion and losses it incurs on its system?

A. Yes. By including realistic estimates of the full COTP schedules in the FNM, the prices at Malin will reflect the marginal congestion and loss value to the CAISO of an injection at Malin. CAISO will apply those prices to the transactions scheduled at Malin. In Appendix A, Case 2 shows that 3,000 MW is modeled as a Malin injection and slightly less than 3,000 MW is flowing onto the CAISO system from Malin to Round Mountain.[13] Note that, since there is no congestion, the prices at Malin and Captain Jack are essentially the same, reflecting the fact

[13] The slight difference is due to the lower reactance of the COTP as compared to the PACI.

that the energy from both scheduling points is flowing over both the CAISO system and the COTP/IBAA system. Approximately two-thirds of the energy that has been scheduled at Malin (into CAISO) and Captain Jack (into SMUD/Western) is flowing across CAISO facilities and creating CAISO losses (and potentially congestion). Approximately one-third of the energy that has been scheduled at Malin (into CAISO) and Captain Jack (into SMUD/Western) is flowing across SMUD/Western facilities and creating SMUD/Western losses (and potentially congestion). If CAISO applies the Captain Jack prices to COTP transactions scheduled with CAISO, it will over recover for congestion and losses on its system, since it will have fully recovered the costs based on the prices applied to the schedules at Malin. In other words, CAISO can't apply its prices to transactions that exceed the amount of its transmission that is being used. The IBAA proposal does just that, however, by applying its prices to transactions scheduled on the COTP, resulting in over collection.

In the 12-bus example, if CAISO applies the Captain Jack price to 400 MW of COTP imports to CAISO at Tracy, in addition to the Malin imports to CAISO, it will recover costs for 400 MW more flow than the approximately 3,000 MW of flow that actually occurs over its transmission facilities. Such over recovery of costs is unnecessary and should not be allowed. If CAISO were allowed to settle COTP Tracy imports at Captain Jack, it would be tantamount to CAISO assuming that its customers scheduling at Malin were entitled to free use of their unscheduled flow over the parallel COTP facilities, but that COTP customers scheduling at Tracy must pay for their unscheduled flow over the parallel PACI facilities.

Q. Do you agree with Mr. Rothleder and Dr. Price's suggestion that COTP losses should be reflected in CAISO's marginal loss calculation? [ISO-1 at 84-85]

A. We agree that if CAISO applies a Tracy price to schedules that are imported on COTP at Tracy, then the CAISO should include the effect of COTP losses in its marginal loss calculations, but we disagree with the CAISO's rationale for including them. CAISO suggests that if COTP schedules are settled at Tracy, the CAISO will not fully recover the cost of losses on its system [ISO-1 at 85]. As we have demonstrated above, if the CAISO includes a realistic estimate of the full COTP transactions in its FNM, it will fully recover all of the loss (and congestion) costs from schedules on its system when COTP transactions are priced at Tracy. Because the CAISO is not faced with a loss through under recovery, such alleged under recovery cannot be used as a justification for including COTP marginal losses in the CAISO's LMPs. CAISO should include the COTP losses in its LMP calculations for another reason, as described below.

If CAISO removes the effect of the COTP losses from its marginal loss calculations, its prices will be distorted, since approximately one-third of Malin schedules flow over COTP facilities. If COTP were still in the CAISO BAA, the

COTP marginal losses would be reflected in CAISO prices. In Appendix A, Case 4 illustrates how the CAISO's LMPs change when the COTP resistances are modeled. As compared to Appendix A, Case 2 the LMP at Malin decreases and the LMP at Tesla increases, so that the spread increases from $3.9/Mwh to $5.4/Mwh. While COTP is no longer within the CAISO BAA and SMUD/Western now incur the marginal cost of COTP losses, SMUD/Western's marginal costs of covering losses are not likely to be materially different from CAISO's marginal costs of covering losses. It is appropriate, and economically efficient, for CAISO to reflect the marginal cost of losses on COTP (including the losses both from COTP scheduled flow and from unscheduled flow on COTP from Malin schedules) in its LMPs, even if CAISO does not directly incur those losses. Doing so would reflect the marginal cost to the system (CAISO and SMUD/Western) of an incremental injection or withdrawal at Malin. Physically, nothing changes when COTP is modeled as being outside the CAISO BAA, so it is not efficient to exclude the COTP losses if the CAISO is attempting to send price signals that will result in an efficient dispatch and use of transmission.

Q. Does PJM remove the effect of the losses of external transmission from the PJM LMP calculations?

A. We have found no evidence that PJM makes an adjustment, similar to the CAISO's default IBAA proposal, to remove the effect of external losses from PJM's marginal loss penalty factors. In fact, just the opposite appears to be the case. PJM Manual 28: Operating Agreement Accounting, Section 2 states that:

V. LOCATIONAL PRICING ALGORITHM[14]

The function of the Locational Pricing Algorithm (LPA) is to determine the real-time LMP values on a five minute basis. The LPA calculates prices for each of the PJM nodes in the state estimator model and for interface busses used as a proxy for transfers to and from PJM and external control areas. The real-time LMPs are defined as the cost to serve the next increment of load at each node bus location for the current system state estimated operating point, taking into account eligible resource real-time offer prices and the buses' location with respect to transmission limitations and incremental system losses…

Section 8 of the same document states:

> Only the losses incurred on facilities included in the PJM network model and, therefore, reflected in the PJM State Estimator are included in the PJM settlements for transmission losses.

PJM includes external facilities in its network model and its state estimator, either as reduced network facilities or as fully-modeled facilities depending on their proximity to PJM. In either case, losses are modeled on those facilities and therefore are included in the PJM LMPs.

[14] Underline added.

<u>The CAISO should include the effects of the external facility losses in its LMPs, but only if transactions using those external facilities are priced at the boundary scheduling points (*e.g.*, Tracy). If CAISO were to attempt to settle COTP transactions at the Captain Jack price, it would be wholly inappropriate to include the COTP losses in the CAISO's LMP calculations</u>. CAISO recognized this point when it developed its approach to removing the effect of the external losses from its LMP calculations, apparently in an attempt to claim that it was not charging for losses incurred on the external facilities.[15] As described above, if the CAISO settles COTP transactions at Captain Jack, rather than Tracy, it will be recovering for losses and congestion costs from COTP transactions that it already will recover from Malin transactions. To then include the affect of the COTP losses would compound the over recovery from the COTP user.

Q. Your discussion thus far has focused on losses. Do the same arguments apply to congestion charges?

A. Yes. All of the arguments that justify settling losses at the Tracy price apply to congestion. That is: (1) the COTP Participants spent hundreds of millions of dollars to construct the line and thereby both increase the reliability of the transmission system and increase the amount of low-cost power that can be imported into California; (2) the COTP Participants bear the cost of any redispatch on their system resulting from the unscheduled flow from the PACI;

[15] The CAISO disagrees that there would be double-counting of losses, because the CAISO's charges for losses will be based only on losses within the CAISO transmission system. [CAISO Response to SVP Follow Up Questions to Joint SVP/SMUD/TID IBAA Questions submitted on February 29, 2008].

(3) the CAISO is prohibited from charging for costs it incurs due to unscheduled flow on its system caused by scheduled flows on the COTP; and (4) the CAISO will fully recover the cost of congestion it actually incurs on its system from the Malin schedules, and therefore cannot recover duplicative congestion charges from the COTP schedules at Tracy.

Q. Can you elaborate on the reasons why the CAISO should use the congestion component at the COTP delivery point at Tracy, rather than at Captain Jack?

A. Yes. The CAISO facilities and the IBAA facilities are highly integrated and operated in parallel. Each party operates its system and incurs the associated costs and losses. The parties do not charge each other for the use of the other party's facilities for flows that are not scheduled to use those facilities. The highly integrated systems are especially evident on the intertie that comprises the COTP and PACI. The combined system operates as one. Any limitations[16] on the combined system are shared proportionally between the two parties.

If there are outages on the underlying 230 kV system that are so severe as to require COTP and PACI schedules to be cut to relieve the constraint, those

16 There are several nomograms, which are determined seasonally in accordance with the WECC criteria, governing the operation of the combined COTP and PACI systems. One of the limitations governing the nomogram could be the potential overload of the Table Mountain-Rio Oso 230 line. Any operational limitations, as defined by the nomogram, are shared proportionally between the two parties.

schedules will in fact be cut (proportionally), and CAISO does not need to rely on its LMPs to send a signal to the market to effectuate the schedule cut; the cuts will take place, if necessary, pursuant to WECC path operations procedures.

Q. Do flows over the PACI/COTP 500 kV transmission system have a material affect in relieving constraints on the underlying 230 kV transmission system?

A. No. As Mr. Law demonstrated in SVP-3, during the period of highest loading, reductions in imports from the Northwest on the PACI/COTP system are less than 2.8% effective at relieving the constraints cited by Mr. Rothleder and Dr. Price [ISO-1 pp. 34-35], and identified in the 2008 CAISO Transmission Plan. Further, as noted by Mr. Law, PG&E is taking steps to eliminate these constraints, with the initial project expected to be completed by May 2009 and the final stage expected to be completed by May 2012. SVP-3 at 6-7.

Q. Is it appropriate for CAISO to assign congestion costs to COTP imports by applying Captain Jack pricing, rather than Tracy pricing?

A. No, it is not. The CAISO actually recognizes that congestion costs on the CAISO system (including both the 500 kV and underlying 230 kV systems) from Captain Jack should be mitigated by noting that parties may be allocated CRRs from Captain Jack to load on the CAISO system. [ISO-1 Executive Summary at 15 and ISO-1 at 89]. Assuming COTP Participants would be allocated CRRs for the full amount of their rights, the CAISO would refund any congestion costs from Captain Jack to COTP participant load. The reason why the CAISO would refund the congestion costs is that, because the COTP transmission actually exists and allows the energy to flow from the Northwest and into the CAISO, the CAISO does not actually incur those congestion costs for the amount of energy that actually flows. Instead, the CAISO pays importers from the Northwest a lower price reflecting the marginal value of the last increment of supply from the Northwest. But because the CAISO charges load a higher price, it will have a significant over recovery of congestion costs. That over recovery is used to pay the holders of CRRs.

Q. If COTP Participants can obtain CRRs to hedge the congestion exposure from Captain Jack to their load in the CAISO, why should COTP Participants insist on pricing COTP imports to CAISO at Tracy?

A. While CRRs would provide a hedge against some of the congestion cost exposure associated with pricing COTP Tracy imports at Captain Jack, they are not a perfect hedge and the hedge they do provide is not without risk. First, the CAISO is offering only the opportunity to *request* CRRs [ISO-1 Executive Summary at 15 and ISO-1 at 89]. They are not guaranteeing that such CRRs would be provided. While one would expect that all Captain Jack CRRs requested by COTP Participants would be feasible, since the physical capability of the COTP facilities exists, and they presumably would be modeled in the CRR FNM, and they would not be available to be allocated to any party without COTP rights, the CAISO's careful choice of words is cause for concern. Second, the CAISO's CRR allocation process requires that sources be verified and limits eligibility to a demonstration of historical usage via contracts of at least 30 days' duration. As Mr. Hance describes in SVP-1 at 9, SVP's usage of COTP is not restricted to contracts of at least 30 day's duration and its usage varies from one year to the next. SVP therefore would not be able to obtain CRRs based on historical usage that would exactly match all future usage. Third, the CAISO limits the total amount of CRRs an LSE may request to its CRR load metric less ETC rights. Any CRRs that SVP might request from Captain Jack would reduce the opportunity for SVP to request a CRR from another source. CAISO would be forcing SVP to obtain a CRR if it wishes to have a financial hedge against congestion costs that CAISO would impose for which SVP already has spent millions of dollars to construct a physical hedge. Such a financial hedge should not limit in any way SVP's ability to obtain CRRs to hedge its other potential congestion exposure, and yet it appears that CAISO would be doing just that. Fourth, the CAISO allocates obligation CRRs, rather than option CRRs, which expose the holder to potential counter-flow congestion costs. An obligation financial instrument is not a comparable substitute for the physical option that SVP currently holds that enables it to schedule imports from the Northwest into the CAISO at Tracy and exports from the CAISO at Tracy into the Northwest. Fifth, CRRs are settled only in the Day Ahead market, and thus would not provide a hedge against post-Day Ahead schedule changes, as should be provided for the physical transmission path. Finally, possession of a CRR does not guarantee that the congestion exposure will be mitigated. It is possible that CAISO might not collect enough congestion revenues from its entire market to fully fund the CRRs it allocates, and thereby not be able to fully fund the allocated CRRs.

Q. Are there more effective ways for the CAISO to insure that a COTP Participant is not charged congestion costs for its COTP imports?

A. Yes. The CAISO developed the Perfect Hedge[17] to reverse out congestion charges from Existing Transmission Contract (ETC) and Transmission Contract (TOR) transactions. In those instances, the CAISO recognized that entities with either contractual rights to transmission on the CAISO Controlled Grid (in the case of ETCs) or with ownership of transmission facilities within the CAISO BAA but not part of the CAISO Controlled Grid (in the case of TORs) should not incur congestion charges when they use those rights. While the COTP is not part of the CAISO BAA, like TOR facilities, the COTP provides physical capability to move power from sources to sinks. Just as TOR holders are not charged for congestion between sources and sinks scheduled on their facilities, COTP participants should not be charged for congestion between sources and sinks on their facilities. The Perfect Hedge could be used to reverse out congestion costs between Captain Jack and Tracy for COTP transactions within CAISO, but the more direct approach would be to settle COTP transactions at Tracy to apply appropriate pricing for both congestion and losses.

[17] The Perfect Hedge reverses out congestion charges from the source to the sink specified in the ETC or TOR, rather than from the source to the CAISO load. It is only applied to the quantity of rights that are actually used, rather than to the maximum amount that could be used.

VI. HARM TO SVP AS A WESTERN BASE RESOURCE CUSTOMER

Q. How will the CAISO's proposed approach harm SVP as a Western Base Resource Customer?

A. The CAISO's proposal to apply Captain Jack pricing to all IBAA imports to the CAISO will increase the cost of delivering Western power to SVP. SVP takes delivery of the Western Base Resource at the Tracy substation. Because the congestion and loss components of the LMP at Tracy are likely to be higher than those at Captain Jack, if the CAISO settles those Tracy imports at the Captain Jack price, the cost to deliver that resource to SVP's load will increase.

Q. Please describe the Western Base Resource entitlement of SVP and discuss why Captain Jack is not an appropriate pricing location for Western Base Resource imports to load within the CAISO.

A. SVP is a Base Resource Customer of Western, having a contractual entitlement to approximately 9% of the Western Base Resource, or approximately 125 MW. The Western Base Resource is the hydroelectric generation from several facilities owned by the United State Bureau of Reclamation in northern California. None of these facilities is located at, or north of, Captain Jack and therefore Captain Jack cannot represent the marginal source of supply of the Western Base Resource to SVP. There are significant restrictions on the sale of the Western Base Resource and, unless SVP were to enter into a long-term layoff of its rights, it must use its entitlement to serve its own load. Consequently, the CAISO's concerns about parties engaging in paper transactions to "move" energy to alternative delivery points do not apply to the Western Base Resource.

Q. Where should SVP's imports of the Western Base Resource be priced?

A. SVP's imports of the Western Base Resource should be priced at the Tracy bus In the same way that the COTP parallels the PACI 500 kV system, Western's 230 kV transmission parallels PG&E's 230 kV network (and the 500 kV PACI/COTP transmission). This system was designed to be highly integrated with PG&E's system to enhance reliability and enable energy to flow from both Western and PG&E hydroelectric facilities in the northern and eastern part of the State to load in the central valley and greater bay area. Like the COTP, Western's transmission provides reciprocal benefits to the CAISO. Mr. Rothleder and Dr. Price showed that flows at one of Western's interfaces with the CAISO, at Cottonwood Substation, are predominately from the CAISO system to the Western system during the system peak hours [ISO-1 at 23]. This pattern is understandable, since PG&E's Pitt River hydroelectric project is a major source of supply and flows to load using both the Western 230 kV transmission and the PG&E 230 kV transmission. Western bears the cost of losses and congestion associated with those flows, just as CAISO bears the cost of losses associated with flows from Western's Base Resource on the PG&E system. Given that Western constructed physical facilities that allow energy to flow from its (and PG&E's) low-cost hydro resources and thereby provides a reciprocal benefit to CAISO, Western imports to CAISO of Base Resource should be settled at the Tracy price.

VII. APPLICABILITY OF PJM INTERCONNECTION EXPERIENCE TO CAISO

Q. Why is it inappropriate to apply the solutions developed by PJM to address its pricing issues at the PJM Southeast and Southwest proxy busses to the instant CAISO proposal?

A. It is inappropriate to apply to northern California the solutions developed by PJM to address its pricing issues at the PJM Southeast and Southwest proxy busses because there are clear differences in the problems the PJM system was facing and the situation in northern California.

Q. Please describe the PJM issue that led to the single Proxy bus solution for Southern PJM.

A. The dominant power flows in the PJM area are from the west to the east. Much of the generation in western Pennsylvania, Ohio, West Virginia, and states further west like Indiana, Illinois, and Kentucky have relatively greater amounts of lower-cost coal, nuclear and hydro electric energy than eastern PJM. Eastern PJM is part of the Boston to Washington DC Northeast Megaregion, which has a correspondingly higher load density and although there is some coal, hydro and nuclear generation in this area, much of the electric energy supply comes from higher-cost natural gas fired generation. This creates a dominate power flow from the west to the east and leads to “transfer limits” becoming binding and high congestion costs occur in the east and therefore high locational price differentials across PJM.

When there have been high congestion cost differentials across PJM, some entities have scheduled deliveries into the eastern parts of PJM using generation sourced in the west and delivered to the eastern scheduling points over contract paths that did not actually result in correspondingly similar incremental flows into the eastern PJM areas. These entities were thereby receiving higher prices for their energy than the value received by PJM. Generally speaking, only about 20% of an incremental increase in western generation will actually arrive in the eastern part of PJM through the eastern delivery points.

Q. Please describe the situation in northern California system and discuss how it presents different challenges than the PJM problem you just described.

A. In some ways the lower-cost energy in the Pacific Northwest and the 500kV transmission in northern California are similar to the lower-cost western PJM energy and the transmission in the western part of the PJM system. The 500 kV PACI/COTP transmission delivers this lower-cost energy into northern California and into the Tracy/Tesla area just as the transmission in western PJM delivers lower-cost energy through the western PJM system and into Eastern PJM. This is where the similarity ends however. PJM has parallel transmission paths, outside its own 500 kV system that begin to the west of PJM and reach into their eastern scheduling points. When generation in the west of PJM schedules energy into these eastern delivery points using the contract paths provided by this outside transmission only about 20% of the energy scheduled actually appears at the eastern scheduling points.

Unlike the situation in PJM, essentially all the low cost energy scheduled to be delivered into northern California over the COTP and PACI lines actually flows on these facilities to the locations where the energy is needed. As the CAISO admitted, there should be minimal congestion on the 500 kV PACI/COTP facilities [ISO-1 at 88]. Further, as Mr. Law demonstrated in SVP-3, flows on the 500 kV facilities have very little impact on constraints on the 230 kV system. Put another way, low-cost energy that is scheduled on the PACI and COTP is deliverable to load in the higher-cost northern California area. This is in sharp contrast to the situation in PJM, in which substantial constraints lead to significant congestion between the low-cost western region and the higher-cost eastern region.

Q. What about the binding "transfer limits" and high congestion that exists in PJM? Won't there be similar limits involving the northern California 500kV transmission?

A. There are binding "transfer limits" between the California Oregon border and northern California as well as to the south and west of Tracy/Tesla. Transfer limits into northern California are managed by WECC and implemented by the BAAs involved including BPA, SMUD, Western, and the CAISO. As Mr.

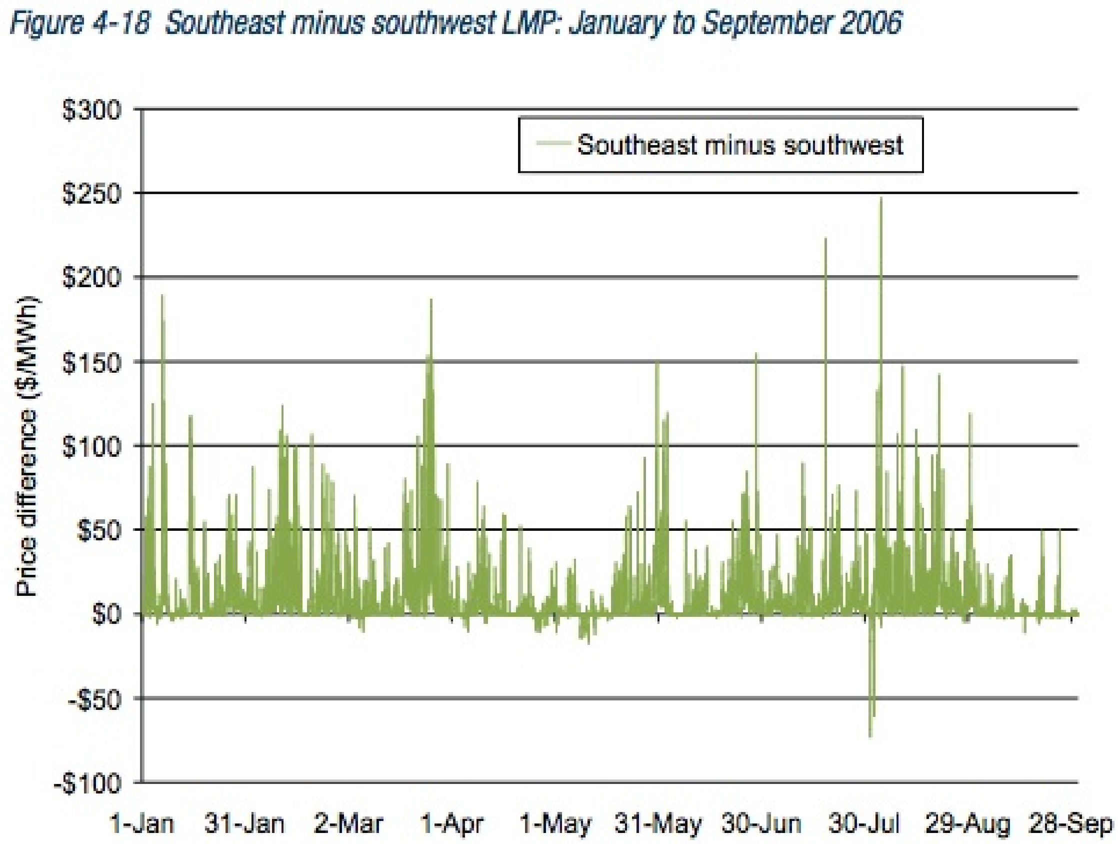
Rothleder and Dr. Price observed, congestion on the COTP 500 kV transmission system between Captain Jack and Tracy should be minimal [ISO-1 at 88], and even if schedules at Malin exceed the Malin scheduling limit, the resultant congestion will not affect the prices at Captain Jack, since the COTP schedules cannot exceed the COTP scheduling limit [ISO-1 at 89]. Thus, the only flow congestion that would be observed at Malin or Captain Jack would be potential "downstream" flow limit congestion, reflecting congestion on the underlying 230 kV transmission facilities.

But as demonstrated by Mr. Law in SVP-3, the flows on the combined PACI/COTP 500 kV transmission system have very little impact on the constraints on the 230 kV transmission system. The very limited potential for congestion differentials between Captain Jack and the CAISO load are in stark contrast to the significant levels of congestion observed between the PJM west and PJM east proxy busses.

Q. Are there other ways in which the issues that occurred in the eastern systems, like PJM, are different from the northern California experience?

A. Yes. First, in the development of the eastern ISOs the initial approach to developing pricing for transactions with external systems was to first develop the most technically or electrically correct approach. It was only after Market Participants began using approaches that produced financial benefits to some Market Participants without providing benefits to the PJM system, that the ISO developed their less desirable single proxy bus pricing approach. As Dr. Harvey noted, PJM implemented the single proxy bus approach at locations at which inefficient scheduling incentives were a problem that needed to be addressed [ISO-3 at 31]. PJM did not consolidate interface buses at other locations, including IESO, Michigan and NYISO interface pricing points. [ISO-3 at 31]. PJM's judgment, however, about which interfaces to combine into a single proxy bus were formed after PJM had obtained actual experience of inefficient scheduling and, based on that experience, PJM was able to determine which buses were problematic and which were not. [PJM 2006 State of Market report at 195 - 199]. In contrast, CAISO is predicting that similar problems <u>might</u> materialize, without considering some critical differences between the situation in northern California and PJM.

Specifically, the locational price differences between the PJM delivery hubs were often substantial [PJM 2006 State of Market report at 197].



Source: PJM 2006 State of the Market Report, p. 197

The situation in northern California, however, is not likely to produce the kind of undesirable effects that occurred in PJM. The congestion differentials between the Tracy 500 kV bus and the Captain Jack 500 kV bus can be expected to be minimal in comparison to the price differentials that occurred in the PJM case. Table 2 is a copy of table developed by the CAISO that shows the monthly average prices including the congestion and loss components that were determined using its LMP Study data for the months of January thru April of 2005. As is readily apparent, these price differences are small -- never larger than a few dollars per megawatthour.

Table 2: IBAA LMPs

Total LMP	Jan 05	Feb 05	Mar 05	Apr 05	Jan-Apr 05
SMUD Hub	48.04	50.58	50.28	53.07	50.47
WAPA Hub	45.84	48.28	48.81	51.61	48.62
MID Hub	47.01	49.38	49.55	52.40	49.56
TID Hub	47.04	49.42	49.61	52.47	49.62
Roseville Hub	48.00	50.59	50.35	53.15	50.50
CAISO's NP15 EZGen Hub	46.17	48.49	48.81	51.22	48.66
37012 LAKE 230 kV	48.14	50.67	50.39	53.17	50.57
37016 RNCHSECO 230 kV	47.92	50.41	50.04	52.85	50.28
37545 COTWDWAP 230 kV	45.53	47.91	48.56	51.37	48.33
30035 TRACY 500 kV	46.40	48.97	49.25	52.00	49.13
37585 TRCY PMP 230 kV	46.33	49.05	49.32	52.09	49.18
30670 WESTLEY 230 kV	46.79	49.22	49.45	52.26	49.41
38230 STANDFRD 115 kV	47.54	49.92	49.90	52.85	50.03
38432 OAKDLTID 115 kV	47.03	49.40	49.59	52.49	49.61
45035 CAPTJACK 500 kV	45.61	48.14	47.99	50.51	48.04

Source: CAISO, Modeling and Pricing of Integrated Balancing Authority
Areas (IBAA) Presentation to Market Surveillance Committee
April 11, 2008, p. 14

This contrasts with the price differences that are shown in Table 3 from the PJM 2006 State of the Market Report. This figure shows that prices were generally $10 to $15/MWh different on-peak, on average for the entire year between some western zones and some eastern zones in the on-peak day ahead market and some zones experienced similar differentials in real time. While it is possible for prices across the COTP and IBAA system to be higher than shown, CAISO has presented no evidence that the magnitude of the differences will approach the prices in the PJM case nor that they will do so as frequently as in PJM.

Table 3: PJM 2006 Zonal Prices

<u>Zonal on – peak hourly LMP (Dollars per MWh): Calendar year 2006</u>

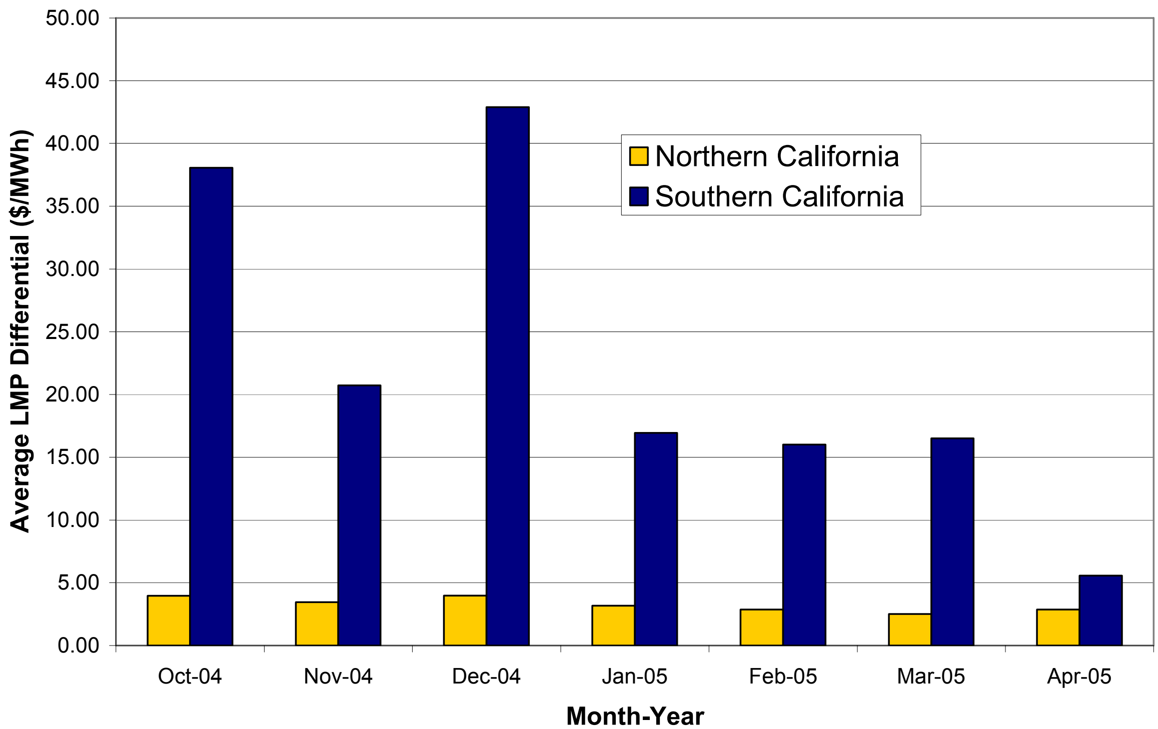
Day Ahead		Real Time	
– AEP	51.91	– AEP	53.55
– AP	58.32	– AP	60.06
– COMED	51.73	– COMED	53.17
– BGE	67.26	– BGE	69.56
– PEPCO	64.60	– PEPCO	64.10

Source PJM 2006 State of the Market Report – Appendix C Table C12 pg 360

In addition, we reviewed the results from CAISO's LMP Study 3C, which used actual market bids from October 2004 through April 2005 as inputs to calculate nodal LMPs. For each hour, we identified both the highest and the lowest intertie price among all of the modeled interties between the CAISO, SMUD, Western, MID and TID. If a party had perfect information, it could choose to schedule energy imports to the CAISO at the highest priced node or exports from the CAISO at the lowest priced node. The difference between those prices represents the maximum amount of value the CAISO could lose if none of the energy actually flowed as scheduled. We preformed a similar analysis for the interfaces in southern California to see if there might be similarities or differences between the interface pricing in the north as compared to the south.

Figure A shows that the monthly mean differential between the lowest priced and highest priced interface nodes in northern California varied between $2.5/MWh and $4/MWh. As compared to the price differentials observed between PJM west and PJM east, these differentials are relatively small. Notably, when compared to the differentials between the lowest priced and highest priced interface nodes in northern California, the southern California differentials are markedly higher.

Figure A: Monthly Average Hourly LMP ($/MWh) Extreme Differentials Among Northern California Interties (11) v. Southern California Interties (13) Under the CAISO LMP Study 3C: Oct'04-Apr'05



Q. Can you comment on the validity of using the LMP Study 3C data for purposes of evaluating the need for single proxy bus pricing?

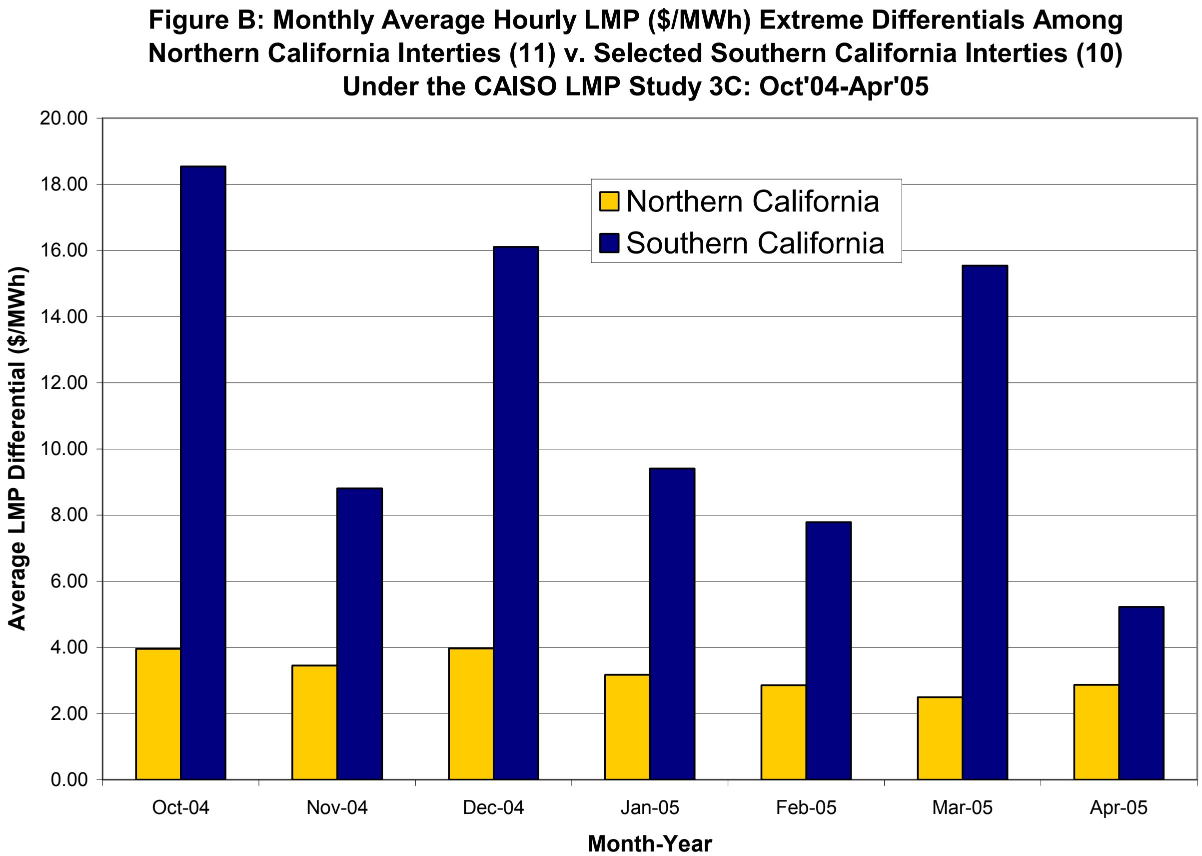
A. While it would be preferable to have actual data from real LMP market bids in the CAISO, given the CAISO's insistence on assuming the worst case scenario without presenting simulated market results, it is reasonable to use the results from the modeling efforts that the CAISO has made public. While the LMP Study 3C results are somewhat dated, the CAISO has refused to develop updated results for more recent periods.[18] These results would reflect higher natural gas prices and consequently should show greater spreads between the nodes. They also would reflect the current configuration of the CAISO's FNM, including the fact that the COTP, MID and TID are no longer in the CAISO BAA. But given that the CAISO intends to model the transmission facilities within those non-CAISO areas, we would not expect the name of the BAA in which the facilities reside to materially affect the modeled prices. In any case, we believe that reviewing simulations that reflect the underlying network in California, and actual supplier market bids is preferable to relying on the experience from a market with significantly different physical characteristics than the CAISO as the basis for a decision to support a less accurate modeling approach.

[18] Because the CAISO staff is fully engaged in MRTU implementation, the schedule for publishing additional LMP Study simulation results has not been determined. [CAISO Response to IBAA Questions, February 15, 2008].

Q. The CAISO intends to include non-CAISO transmission facilities in the FNM that were not included in the LMP Study 3C network model, could that have an affect on the results for southern California?

A. Yes. Since the LMP Study 3C was performed, the CAISO has identified a problem with the network model in southern California which could result in very low prices at specific southern California interfaces. To correct the problem, the CAISO intends to model non-CAISO transmission facilities at key locations. To approximate the results of the CAISO's new approach, we removed from the analysis the low-priced nodes that the CAISO identified in its Partial Loop Proposal white paper.[19] Removing those inter-tie points (nodes) reduced the spread between the southern California interface nodes, but that spread is still markedly higher than the northern California spread, as shown below in Figure B.

[19] "Implementation of "Partial Loop" Intertie Network Configuration for MRTU," California ISO, January 02, 2008.



Q. What do you conclude from this analysis?

A. First, the analysis indicates that CAISO's decision to impose single hub pricing for northern California is premature. The data do not support the CAISO's concern that there is a significant likelihood for parties in northern California to improperly profit from scheduling at interfaces over which the energy does not flow at the levels of the schedules. As Mr. Hance demonstrates at SVP-1 at 19-20, there can be significant transactions costs to wheel power between BAAs, which further reduces the potential for improper scheduling.

VIII. OTHER ISSUES WITH THE CAISO'S PROPOSED PRICING

Q. Were there other issues raised in the CAISO proposal that appear incorrect or inconsistent?

A. Yes. As discussed in the CAISO filing there will be different prices for imports and exports.

> *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.*
>
> **ATTACHMENT I**
>
> Opinion of the Market Surveillance Committee of the California Independent System Operator Corporation at 6.

The CAISO's assumption that exports from the CAISO to an adjacent BAA would sink at the high – price location is consistent with the concept that the purchasing BAA would decrement its highest cost resource in favor of lower-cost imports. But CAISO applies faulty logic in assuming that imports to the CAISO would result from the neighboring BAA incrementing its lowest cost resource (*i.e.*, energy from the Northwest).

Any operator of a power system that is attempting to serve load in its system in the lowest cost manner will rely on its own generation unless it can purchase energy for less than it can generate it. If energy becomes available from outside its area for a lower-cost, the operator will, as the CAISO correctly assumes, decrease the output of its highest cost unit to support the import of the lower-cost energy. However, if instead of being able to import energy from an outside area, the outside area is willing to purchase energy from the operator, the operator will <u>increase the output from its next available (*i.e*., higher-cost) unit to provide that energy</u>. It would be irresponsible for a system operator to purchase low cost energy using its available transmission, but then provide that energy for the benefit of the adjacent BAA, while using its highest cost energy for its own customers. But this is essentially what CAISO would impost on both the neighboring BAAs and on COTP imports.

IX. <u>CAISO "MAY 30" COUNTERPROPOSAL</u>

Q. Can you comment on the CAISO's May 30 Counterproposal and the supplemental details CAISO provided in the June 17 Filing?

A. Yes. The CAISO's May 30 Counterproposal provided very limited information, which was supplemented with key details and restrictions in the June 17 Filing. Due to the limited time to respond to the June 17 Filing, it was not feasible for the parties to meet to discuss the CAISO's proposal. Based on the information in the June 17 Filing, it appears that the CAISO is beginning to recognize the potential for serious problems if COTP transactions are priced at Captain Jack. The CAISO now appears willing to settle the loss component (but not the congestion component) for certain COTP imports serving load within the CAISO at Tracy, by providing an exemption for the Captain Jack loss component. 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. [ISO-1 at 84].

Q. Are there additional conditions contemplated by the CAISO proposal?

A. Yes. The CAISO contemplates that the 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. The exemption would not apply during any period in which the IBAA entity is simultaneously importing power using the COTP and exporting from any point on the CAISO Controlled Grid. The proposal would not cover congestion charges, apparently because the CAISO expects the congestion to be small, and any remaining congestion to be able to be hedged via CRRs. The IBAA Entities would be required to report all COTP schedules prior to the CAISO's Day Ahead scheduling deadline. [ISO-1 at 86].

Q. What are some of your criticisms of the proposal?

A. Besides failing to include settlement of congestion charges at Tracy, the CAISO proposal is deficient for several reasons. First, the limitations on the COTP usage that would be eligible for Tracy loss pricing significantly limits the benefits of the proposal, and unnecessarily discourages the use of valuable local resources. It appears that the CAISO is attempting to at least partially withdraw the Tracy exemption when a party has generation or purchases internal to the CAISO. This limitation would appear to discourage an IBAA entity from making resources available within the CAISO any time the sum of its COTP imports and internal resources and purchases would exceed its load, unless the incremental profit from dispatching the internal resources exceeds the additional Captain Jack to Tracy congestion and loss charges. This would have the effect of removing from the market resources that otherwise would be economical to dispatch during some intervals, which will create the same problems we addressed earlier. This approach seems to be a continuation of the mistaken belief that imports from the Northwest using COTP are somehow the "marginal" resource, when in fact the opposite is true.

Besides the inefficiency suggested by this restriction, there is an inequity. All COTP imports to the CAISO at Tracy face the same duplicative congestion and loss charges under the default IBAA proposal. To afford the Tracy loss pricing to certain COTP imports, but not to others, is discriminatory and does not make sense. It does not matter whether the COTP import is being used to serve the IBAA entities load, or some other LSEs load within the CAISO or an entity's load in the southwest. The benefits and costs to the CAISO of an import from the Northwest to Tracy using the COTP do not change by virtue of the specific customers to whom the energy is scheduled. Nor do they change depending on whether the IBAA entity is dispatching other resources or making market purchases. Simply put, the Tracy loss pricing should apply to all COTP imports (and exports).

Second, the proposal does not address congestion charges. As we discussed earlier and Mr. Hance discussed at SVP-1 at 7-9, the opportunity to request CRRs to provide a financial hedge has severe limitations, and would not adequately compensate for the exposure to congestion costs created by the CAISO's Captain Jack pricing.

While we have serious concerns about the CAISO's proposal, we are hopeful that it is an indication that the CAISO recognizes the value provided by the COTP and the potential problems presented by the CAISO's default pricing proposal that we have described. In the spirit of seeking a workable solution, we suggest the following alternative approach.

X. PROPOSED ALTERNATIVE APPROACH

An alternative approach should be taken to avoid the harm that would be caused by CAISO's IBAA proposal, for the benefit of all CAISO Market Participants. Specifically,

a. The CAISO must include in its Day Ahead and real-time market models realistic estimates of total energy flows on the COI, including those related to transactions that are not scheduled in the CAISO markets. COTP imports should be modeled as sourced in the Northwest (Captain Jack) and COTP exports should be modeled as sinking in the Northwest (Captain Jack).

b. COTP imports and exports should be priced at their intertie scheduling point (Tracy). Scheduling point pricing could be accomplished by the CAISO providing a credit for any loss and congestion charges between Captain Jack and Tracy, recognizing

   - that the COTP Participants invested hundreds of millions of dollars to build transmission that increased reliability and access to low-cost energy; and
   - that the COTP provides reciprocal benefits to the CAISO, including support for parallel flows and recovery of the associated congestion and losses; and
   - that the CAISO will fully recover the congestion and losses costs it

actually incurs by applying correct prices at Malin to the schedules at Malin.

c. The crediting mechanism can be linked only to the amount of a party's rights to COTP capacity (*e.g.*, it can't be reduced for any load served by ETCs, internal generation or CAISO resources, nor for any third party purchases or sales).

d. Transactions with Western should be priced at the intertie scheduling point (*e.g.*, Tracy).

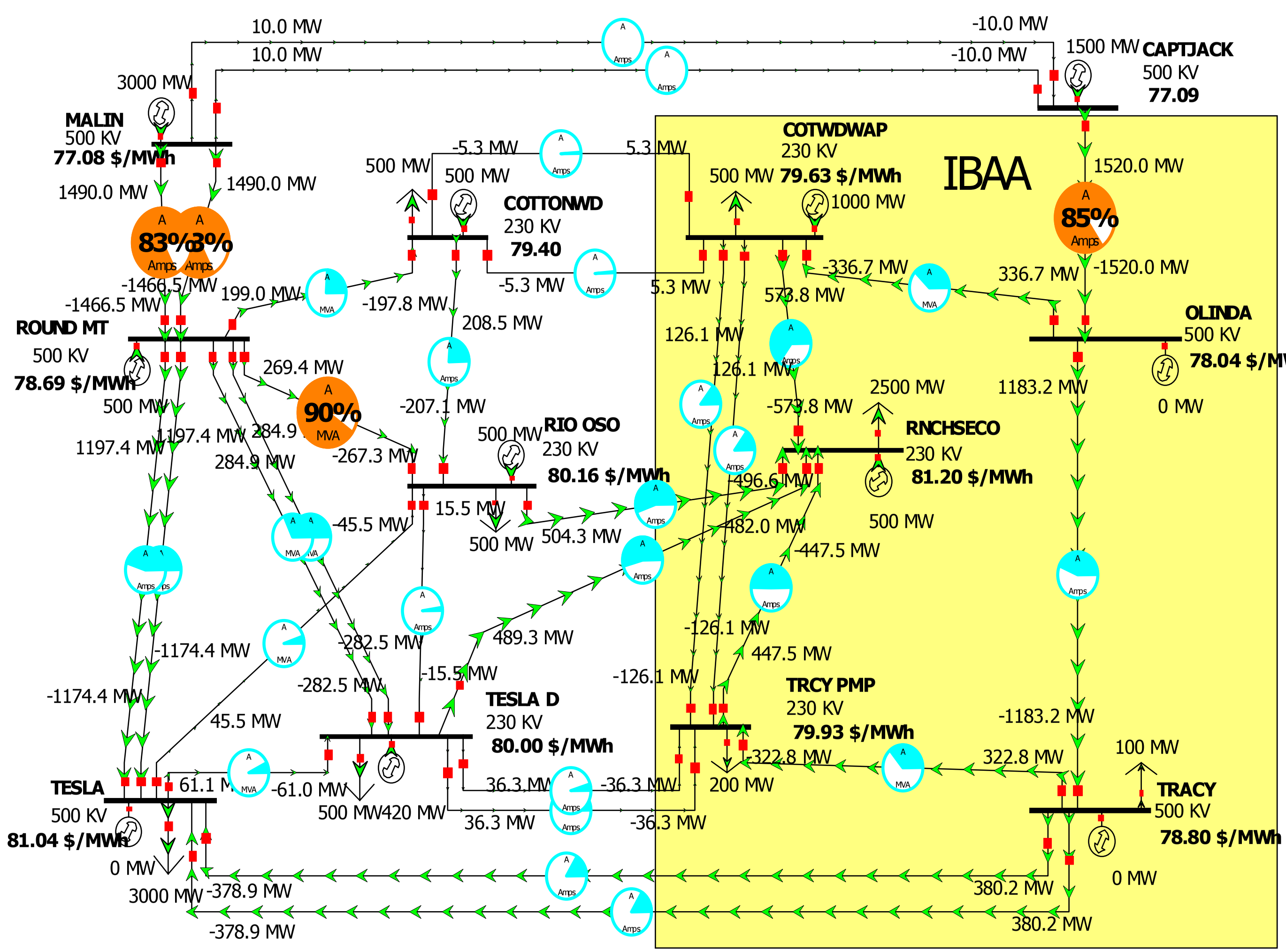
e. The CAISO cannot require data from an entity that is not within that entity's control, and the CAISO must limit the data it seeks to a realistic scope, with protections for the BAA entities with respect to the use of that data.

f. The CAISO should include the effect of losses on external transmission facilities modeled in its FNM and state estimator in its LMP calculations.

Q. Does that conclude your affidavit?

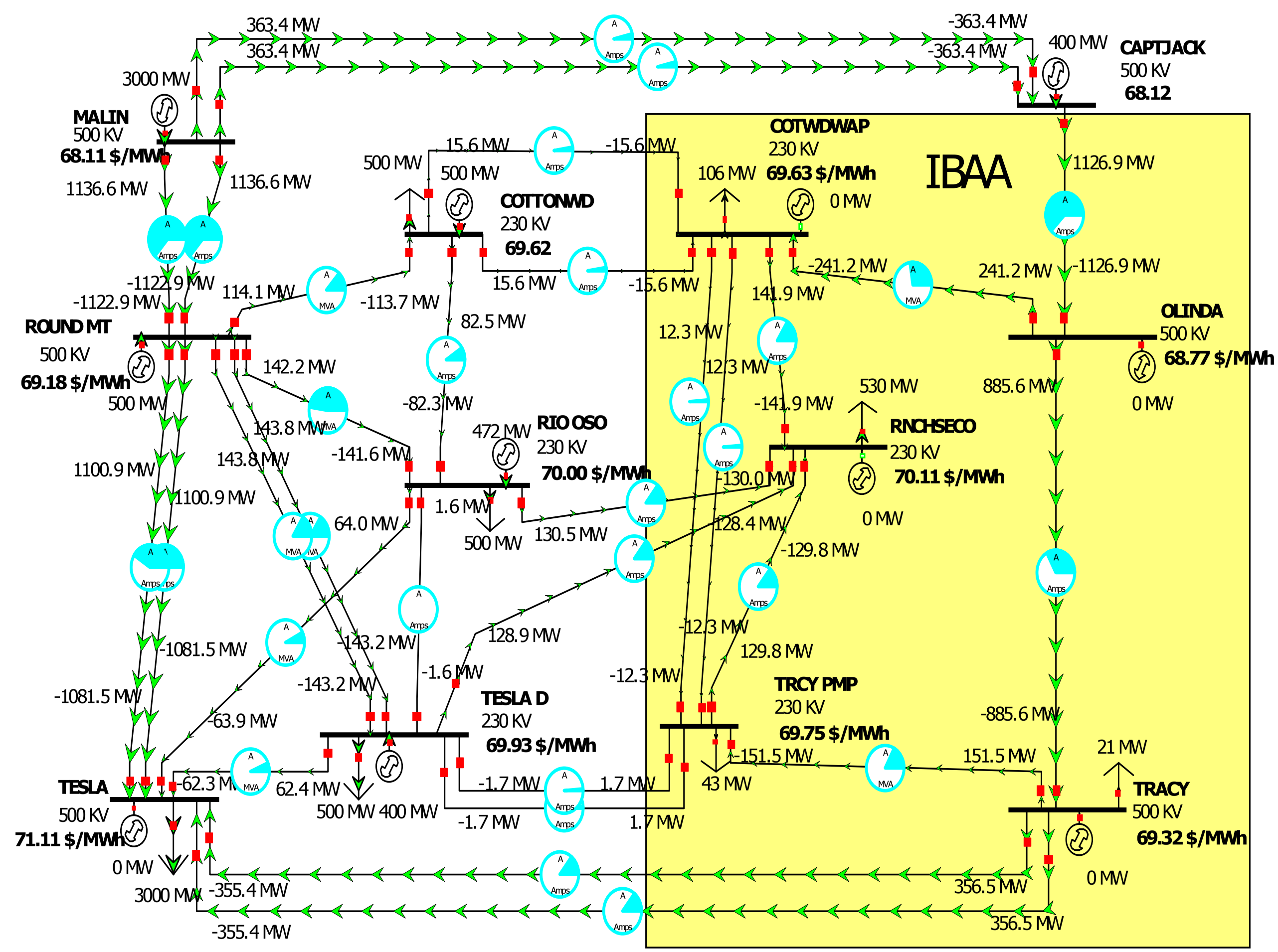
A. Yes.

Base Case: “Complete” Model of IBAA Loads and Resources (no IBAA Resistance)



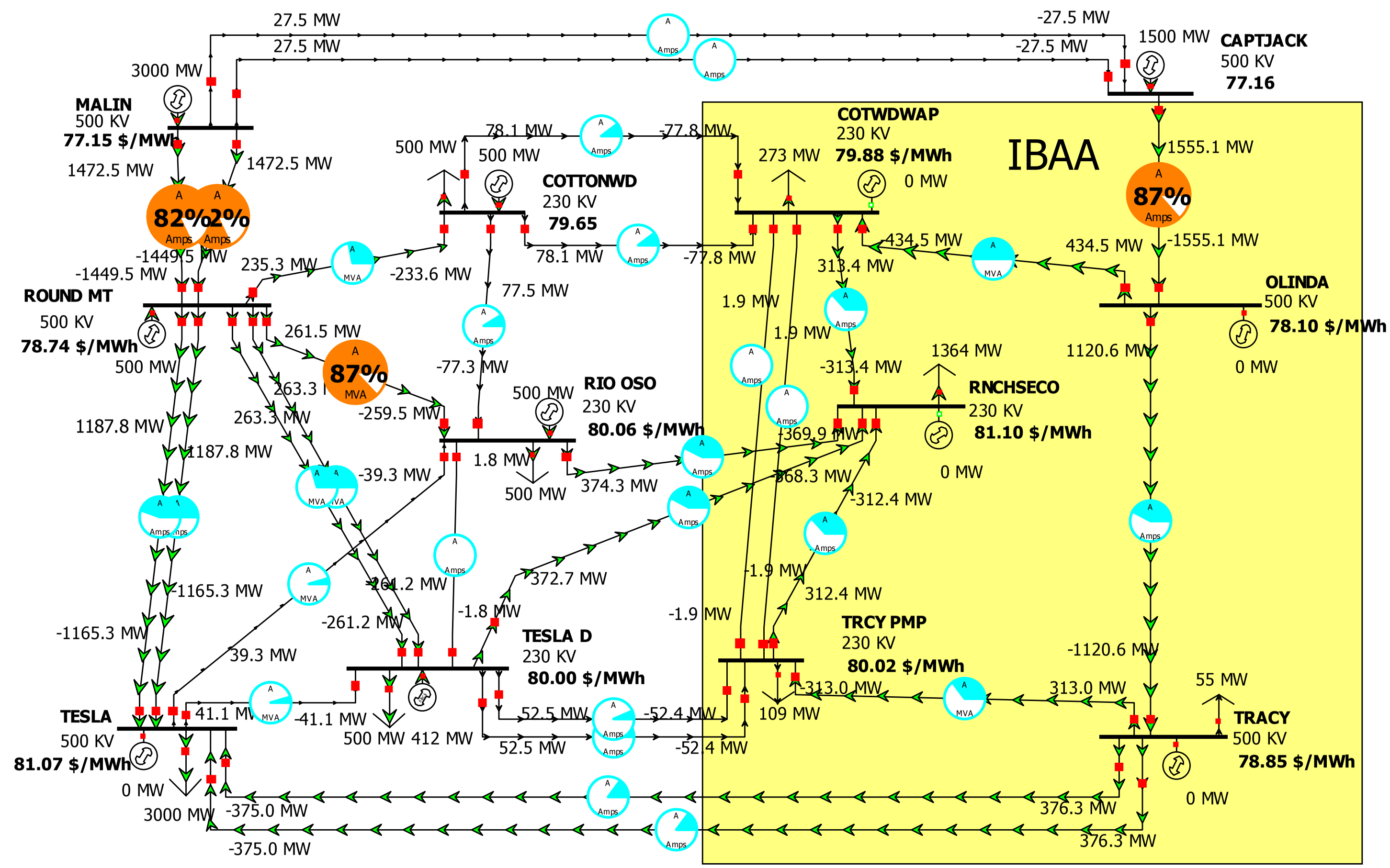
Case 1: CAISO Default Approach - 400 MW Gen @ Captain Jack, 700MW of Net Export to IBAA (no IBAA Resistance)

Note: Because 1,100 MW of IBAA load and 1,100 MW of COTP injections are no longer visible to CAISO, the modeled losses are lower, placing a lower cost resource on the margin. Therefore, the system marginal price has decreased by approximately $10/MWh.



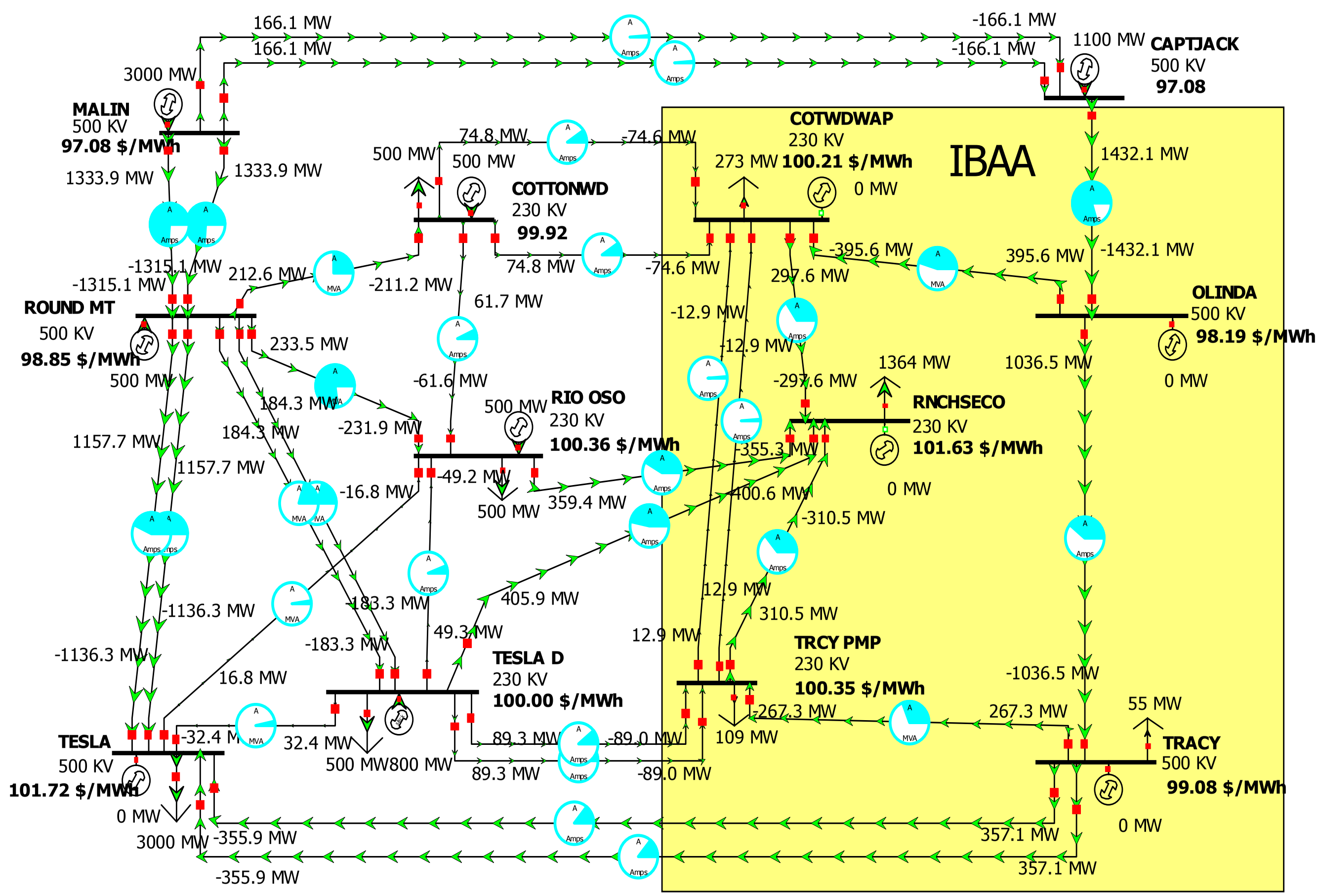
Case 2: All COTP Transactions Modeled - 1,500 MW Gen @ Captain Jack, 1,800MW of Net Export to IBAA (No IBAA Resistance)

Note: Flows and prices are very similar to the flows and prices in the Base Case. The relatively minor differences are due to the IBAA modeling approximation of the net IBAA load, rather than the full IBAA loads and resources.



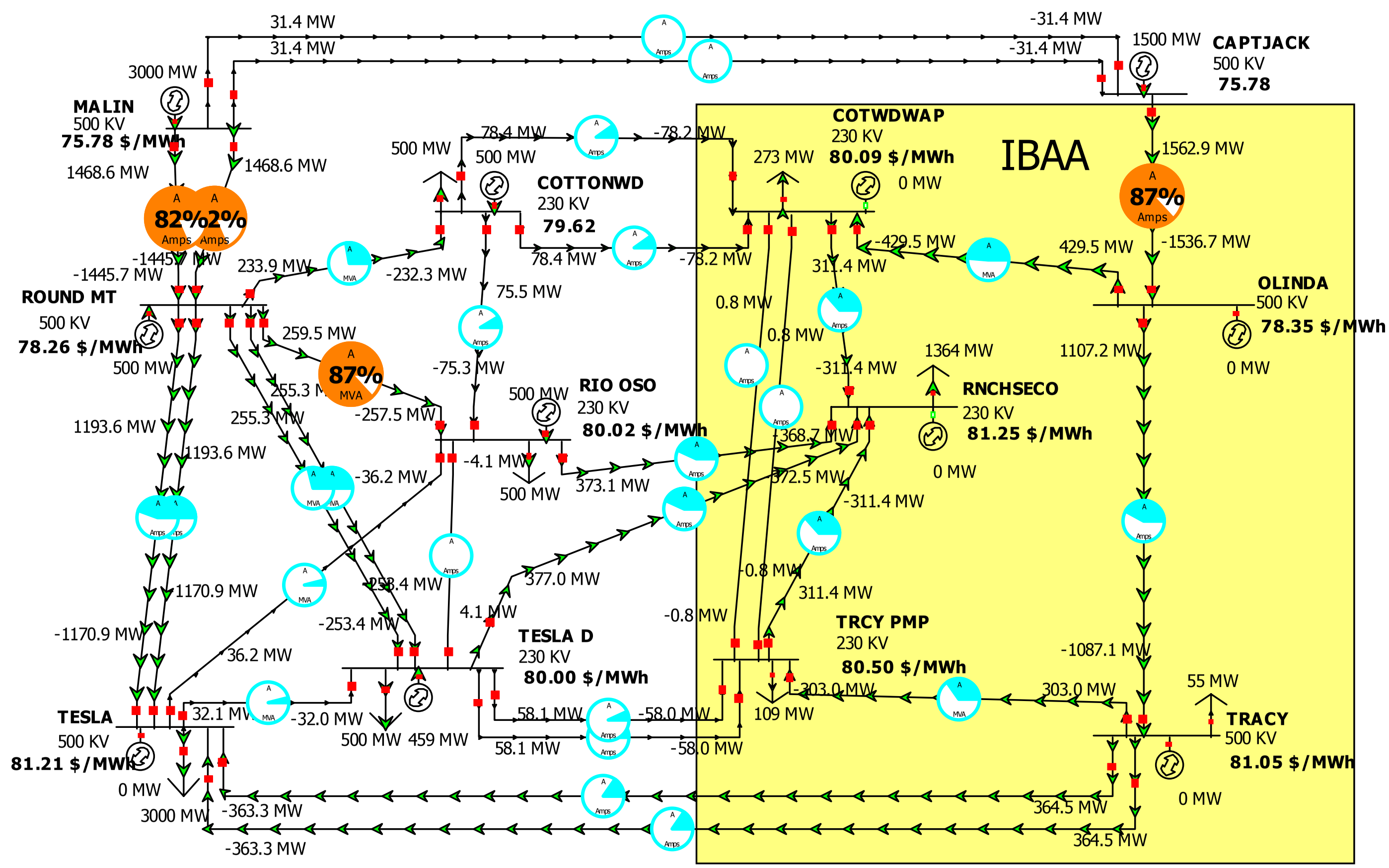
Case 3: 400 MW of COTP Becomes Uneconomic - 1,100 MW Gen @ Captain Jack, 1,800 MW Net Export to IBAA (no IBAA Resistance) (same as Case 2, but CAISO models IBAA COTP usage)

Note: LMPs rise for all loads in CAISO relative to Case 2. Internal resources would have to be used to offset 400 MW of foregone northwest imports.



Case 4: All COTP Transactions Modeled - Same as Case 2, but with Resistances Modeled for COTP Only

Note: With losses modeled on COTP, LMP at Tracy goes up, whereas LMP at Captain Jack goes down relative to Case 2 (w/o resistances on COTP). Therefore, the divergence between Tracy and Captain Jack LMPs increase significantly from \$1.7/MWh in Case 2 to \$5.3/MWh in Case 4.



The California ISO provided the power flow examples to support the presentations used in the April 11th joint Market Surveillance and Stakeholder Integrated Balancing Authority Areas proposal meeting, on April 16, 2008 at http://www.caiso.com/1fab/1fab9f5167a60ex.html.

The reactances (X) on the COTP facilities Base Case as well as Cases 1 through 4 were changed from 0.01110 p.u. to 0.007 p.u. and 0.01293 p.u. to 0.007 p.u. on Olinda-Tracy and Olinda-Captain Jack lines, respectively as shown in Table B-1. Base Case and Cases 1 through 3 assumed zero (0) resistances (R) on both the COTP facilities, whereas Case 4 incorporated resistances as shown in Table B-1.

Table B-1: COTP Transmission Lines' Specifications- Resistance (R) and Reactance (X)

From Number	From Name	To Number	To Name	R	X
30020	OLINDA	30035	TRACY	0.00159	0.007
30020	OLINDA	45035	CAPTJACK	0.00106	0.007

Tables B-2, B-3, B-4, B-5 and B-6 provide the generation and loads on each bus as modeled in Base Case, Case 1, Case 2, Case 3 and Case 4, respectively.

Table B-2: Generation (MW) and Load (MW) on each bus in the Base Case

Number	Name	Gen (MW)	Load (MW)
30005	ROUND MT	500	-
30040	TESLA	-	3,000
30106	COTTONWD	500	500
30330	RIO OSO	500	500
30625	TESLA D	420	500
40687	MALIN	3,000	-
30020	OLINDA	-	-
30035	TRACY	-	100
37016	RNCHSECO	500	2,500
37545	COTWDWAP	1,000	500
37585	TRCY PMP	-	200
45035	CAPTJACK	1,500	-

Table B-3: Generation (MW) and Load (MW) on each bus in Case 1

Number	Name	Gen (MW)	Load (MW)
30005	ROUND MT	500	-
30040	TESLA	-	3,000
30106	COTTONWD	500	500
30330	RIO OSO	472	500
30625	TESLA D	400	500
40687	MALIN	3,000	-
30020	OLINDA	-	-
30035	TRACY	-	21
37016	RNCHSECO	-	530
37545	COTWDWAP	-	106
37585	TRCY PMP	-	42
45035	CAPTJACK	400	-

Table B-4: Generation (MW) and Load (MW) on each bus in Case 2

Number	Name	Gen (MW)	Load (MW)
30005	ROUND MT	500	-
30040	TESLA	-	3,000
30106	COTTONWD	500	500
30330	RIO OSO	500	500
30625	TESLA D	412	500
40687	MALIN	3,000	-
30020	OLINDA	-	-
30035	TRACY	-	55
37016	RNCHSECO	-	1,364
37545	COTWDWAP	-	273
37585	TRCY PMP	-	109
45035	CAPTJACK	1,500	-

Table B-5: Generation (MW) and Load (MW) on each bus in Case 3

Number	Name	Gen (MW)	Load (MW)
30005	ROUND MT	500	-
30040	TESLA	-	3,000
30106	COTTONWD	500	500
30330	RIO OSO	500	500
30625	TESLA D	800	500
40687	MALIN	3,000	-
30020	OLINDA	-	-
30035	TRACY	-	55
37016	RNCHSECO	-	1,364
37545	COTWDWAP	-	273
37585	TRCY PMP	-	109
45035	CAPTJACK	1,100	-

Table B-6: Generation (MW) and Load (MW) on each bus in Case 4

Number	Name	Gen (MW)	Load (MW)
30005	ROUND MT	500	-
30040	TESLA	-	3,000
30106	COTTONWD	500	500
30330	RIO OSO	500	500
30625	TESLA D	459	500
40687	MALIN	3,000	-
30020	OLINDA	-	-
30035	TRACY	-	55
37016	RNCHSECO	-	1,364
37545	COTWDWAP	-	273
37585	TRCY PMP	-	109
45035	CAPTJACK	1,500	-

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator) Docket No. ER08-1113-000

I, Douglas A. Boccignone, declare under penalty of perjury, that the foregoing questions and answers labeled as the Flynn RCI Panel Affidavit, were prepared by us, with the assistance of others working under our direction and supervision, and the facts contained in those answers are true and correct to the best of my knowledge, information and belief.

Dougl A. Boccignone
Douglas A. Boccignone

State of California)
County of Contra Costa)

On 7.8.08 before me, Emily C. Wesolek notary public personally appeared Douglas A. Boccignone 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.

Signature: (Seal)

EMILY C. WESOLEK
COMM. # 1669049
NOTARY PUBLIC - CALIFORNIA
CONTRA COSTA COUNTY
My Commission Expires May 22, 2010
GMN1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator) Docket No. ER08-1113-000

I, Kevin T. Wright, declare under penalty of perjury, that the foregoing questions and answers labeled as the Flynn RCI Panel Affidavit, were prepared by us, with the assistance of others working under our direction and supervision, and the facts contained in those answers are true and correct to the best of my knowledge, information and belief.

Kevin T. Wright

State of Pennsylvania)
County of BERKS)

On July 8th, 2008 before me, Karen A. Bednar, Notary Public. personally appeared Kevin T. Wright 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 Pennsylvania that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature: Karen Bednar (Seal)

Commonwealth of Pennsylvania
NOTARIAL SEAL
KAREN A. BEDNAR, Notary Public
Wyomissing Boro, Berks County
My Commission Expires June 27, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator) Docket No. ER08-1113-000

I, Pushkar G. Waglé, declare under penalty of perjury, that the foregoing questions and answers labeled as the Flynn RCI Panel Affidavit, were prepared by us, with the assistance of others working under our direction and supervision, and the facts contained in those answers are true and correct to the best of my knowledge, information and belief.

Pushkar G. Waglé

Pushkar G. Waglé

State of California)
County of El Dorado)

On 7/7/08 before me, Stacey Gilmore personally appeared Pushkar G. Waglé 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 and official seal.

Signature: Stacey Gilmore (Seal)

STACEY DAWN GILMORE
COMM. #1635803
NOTARY PUBLIC • CALIFORNIA
EL DORADO COUNTY
Comm. Exp. JAN. 7, 2010