CONGESTION MANAGEMENT IN CALIFORNIA

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I. OVERVIEW

The development of competitive decentralized electricity markets is, and always has been, dependent on employment of market-clearing prices, based on locational marginal pricing (LMP), to clear the forward and real-time imbalance energy and transmission markets coordinated by the ISO. Pricing of congestion using LMP provides the basis for efficient pricing of both energy and transmission, and valuing financial transmission rights.

It is no accident that markets based on locational marginal pricing – PJM, New York, New Zealand and elsewhere -- are succeeding in precisely the areas where the California market has been unsuccessful. Because LMP prices are market-clearing prices, they generally eliminate the need for constrained-on and constrained-off payments, which have been a continuing source of California market problems, and will remain a problematic market feature under the CAISO's proposed new congestion management system. Because LMP prices are consistent with the system operator's actual dispatch, and forward prices are determined by generation schedules that are consistent with real-time operation LMP-based markets do not have the incentive problems California has with generators providing congestion management.

In addition to these well known short-run operational advantages, LMP-based markets benefit from the efficient price signals that LMP provides to those considering long-run investments in new generation (including distributed generation), load-management and other demand responses and transmission upgrades that help reduce or eliminate congestion. In the eastern LMP markets, we are already seeing the benefits of these efficient price signals. Not only are new entrants seeking to build thousands of megawatts of new generation – that is true in California, as well – *but they are proposing*

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to build it in the right locations, those with the highest locational prices. Moreover, they have proposed these plants without the need for regulatory or ISO intervention of the type the CAISO must still consider for its undefined NewGen Policy. Further, despite much skepticism about the ability of market prices to stimulate economic transmission upgrades, proposals to build unregulated transmission are starting to appear in response to the efficient price signals provided by LMP.

II. REFORMING CALIFORNIA CONGESTION PRICING

In the long-run, the California electricity market, like markets elsewhere, ought to evolve to an LMP based pricing system in both the day-ahead and real-time markets, consistent with the evolution of electricity markets elsewhere in the U.S. Many changes in pricing, scheduling and settlements would be required to fully implement such a change. Much of the needed reform of the California electricity market can be achieved by focusing now on a few critical issues:

- The market separation requirement should be voluntary, not mandatory;
- The CAISO should manage congestion in the day-ahead, hour-ahead and real-time markets on a consistent basis (day-ahead and hour-ahead schedules should be feasible in real-time);
- The CAISO's congestion pricing system should be consistent with the CAISO's congestion management dispatch;
- The CAISO should shift to LMP pricing for generation in real-time, settling deviations between generator day-ahead schedules and real-time injections at real-time LMP prices;
- The CAISO should increase the number of zones in the day-ahead market;
- Transmission rights should be defined as point to point financial rights in the form of either obligations or options.

These changes will not make the market more complex; they will make it simpler. Eliminating the mandatory market separation requirement will permit generators to make redispatch more broadly available in the day-ahead market. Using a consistent set of transmission constraints will simplify the congestion management process by avoiding the need to create artificial commercial models. Moreover, day-ahead and hour-ahead schedules that are feasible in real-time will reduce the need for real-time redispatch and avoid the need for complicated rules to limit gaming. Consistency between the CAISO's congestion pricing system and dispatch will simplify grid operation because generators will have an incentive to operate as dispatched, and prices will provide an accurate signal for needed generation, transmission and load management investments. Increasing the number of zones in the day-ahead market and shifting to LMP pricing in real-time will both provide better price signals and allow reliance on financial incentives rather than command and control to maintain reliability. Point-to-point transmission rights will simplify hedging of commercial contracts.

Below we provide an brief description of the pricing reform proposals previously developed and described by the Reform Coalition as a transition strategy for the California electricity market[2] and provide a few comments on how such a pricing system could evolve over time.

A. Day Ahead Market

The day-ahead market could initially continue to be based on zonal pricing for generators, loads and transmission customers, which could entail constrained-on payments to generators scheduled in the day-ahead market.[3] The day-ahead schedules would be determined, however, based on the transmission constraints enforced in real-time, so that day-ahead schedules would be feasible.[4] Moreover, there would be no distinction between intra-and inter-zonal congestion, the CAISO would manage transmission congestion in a single process, and there would be no need for iteration.[5]

Market participants would be able to enforce market separation requirements if they wished but this would be optional, and generators willing to provide congestion management to any market participant would be permitted to offer congestion management to any market participant.

The CAISO would manage congestion in the day-ahead market based on bids, balancing the transmission system on a least-cost basis. The nodal prices determined by the resulting schedules would be calculated and posted. The day-ahead nodal energy and transmission prices would reflect the full cost of marginal losses. Day-ahead zonal prices for loads would be calculated as the load weighted average of the day-ahead nodal

[2] Reform Coalition documents can be accessed on the CAISO website at www.caiso.com/clientserv/congestionreform.html, including: "Principles for Congestion Pricing Reform Using Voluntary Balanced Schedules and Voluntary Zonal Pricing" (5/9/00 "Response of Reform Coalition to Questions Asked by the California Power Exchange" (5/9/00), "California Congestion Management: A Reform Proposal" (4/3/00), and "Comments of the Reform Coalition on the CAISO's July 11, 2000 Draft Proposals for Congestion Management Reform" (7/28/00), "Reform of the California Electricity Market, A Path Forward," (3/30/00). In addition, the Reform Coalition distributed a lengthy presentation entitled "Voluntary Price Aggregation", May 9, 2000 that is not posted.

[3] Such a reliance on zonal pricing, even as a transition step, will inevitably compromise the locational signal for generation location decisions and require command and control restrictions on transmission schedules. Eleven zones are, however, an improvement over three zones, if market forces are permitted to set zonal prices. A shift to LMP pricing in the day-ahead, hour-ahead, and real-time markets would be the ideal, but rapid implementation of the changes described above would address many serious problems in the California electricity market. The steps described are a necessary part of a transition to an LMP based system in day-ahead, as well as real-time markets.

[4] LMP pricing in real-time would provide financial incentives for generators to perform on their day-ahead schedules, even if they were scheduled to operate out of merit with respect to the zonal price in the day-ahead market.

[5]As described by the Reform Coalition, generators and loads could be given the option of buying and selling power in the day-ahead market at either zonal or LMP prices. This approach has the attraction that zones could automatically in effect split, if intra-zonal congestion in the day-ahead market were ever to become commercially significant from the perspective of market participants. See Reform Coalition, March 20, pp. 5-6, April 3, pp. 15-16, 22, May 9, pp.3-4 and "Voluntary Price Aggregation", May 9, 2000.

prices within the zone. Day-ahead zonal prices for generators would be calculated as the generation weighted average of the day-ahead nodal prices within the zone. It would therefore be possible for day-ahead load and generation prices within a zone to differ. The CAISO would publish the constraint shadow prices in the day-ahead market.

All generator and transmission customer schedules in the day-ahead market would be location specific. Day-ahead load schedules would be zonal and would settle at zonal prices. All day-ahead schedules would be financial commitments.

B. Hour-ahead and Real-time Markets

The CAISO would calculate hour-ahead and real-time LMP prices based on its least cost balancing of the transmission system taking into account transmission schedules, generator offers, and - when those become a reality - real-time load bids. The hour-ahead and real-time LMP prices would reflect the full cost of marginal losses.

All deviations of gross hour-ahead generator schedules from day-ahead schedules and all deviations of real-time generator injections from gross hour-ahead schedules would settle at the LMP prices. Loads would settle all their deviations of gross hour-ahead schedules from day-ahead schedules and all actual or profiled deviations of real-time load from gross hour-ahead schedules at hour-ahead and real-time LMP prices. All loads with appropriate real-time time of use metering and opting to be subject to nodal pricing would have the option of providing ten-minute and replacement reserves to the CAISO. All loads would therefore be able to sell back the difference between their day-ahead or hour-ahead schedule and actual or profiled real-time consumption at real-time prices.

C. Financial Rights

Financial rights (FTRs) would be defined on a point-to-point basis and would be available to market participants through an auction. These financial rights could be purchased in the form of either obligations or options, at appropriate market clearing prices. FTRs would settle at day-ahead prices. [6] Because FTRs would be defined on a point-to-point basis they would not be affected by future changes in zone definitions, because each FTR would be defined to a particular point, falling within a particular zone. The holders of FTR options would be paid the difference between the congestion component of the day-ahead price at the withdrawal location and the injection location if that difference were positive and would neither receive or make payments if the difference were negative. The holders of FTR obligations would be paid the difference between the congestion component of the day-ahead price at the withdrawal location and the injection location if that difference were positive and would pay that difference if it were negative.

[6] These day-ahead prices could initially be zonal. A transition to LMP pricing in the day-ahead market would not disturb the FTRs because they would be defined on a point to point basis.

In addition, the general approach to inter-zonal congestion cost allocation would be to assign to the loads located within the LRAs the economic value of the existing transmission grid in serving the loads within those LRAs during times of transmission congestion. This assignment could take the form either of an assignment of FTRs or the assignment of FTR auction revenues to those loads. [7] Under either approach, the intent would be to insulate the loads within the LRAs from the financial impact of congestion pricing on that portion of those loads that is met through imports using the existing transmission grid.

Assign FTRs Approach:

Entities with existing firm transmission rights to serve loads within a given zone would be able to convert those transmission rights into point to point FTR obligations or FTR options from their generation resource to their load within that zone. For each LRA within SP15 or NP 15, additional FTR options would be defined from all generation in the current zones (SP 15 and NP15) to the distribution company loads within the LRA in proportion to the capacity of that generation up to the transmission limit into the LRA. These FTR options would be allocated proportionately to all LSEs serving distribution company load within the new zones on a monthly basis. [8]

Assign Auction Revenue Rights Approach:

Entities with existing firm transmission rights into a given zone would be able to convert those transmission rights into point-to-point FTRs or FTR options to their load within that zone. In addition, for each LRA within SP15 or NP 15 Auction Revenue Rights (ARRs) would be defined from all generation in the current zones (SP 15 and NP15) to the distribution company loads within each LRA in proportion to the capacity of that generation up to the transmission limit into the LRA. These ARRs would be allocated proportionately to all LSEs serving distribution company load within the LRA on a monthly basis and would entitle the holder to the revenues in the FTR auction for an FTR corresponding to the ARR. Only ARRs having positive values in the FTR auction would be allocated to LSEs.

D. Market Power Mitigation

Congestion pricing reform in California has been greatly complicated by the need to distinguish transmission congestion arising from generation cost differences with that arising from the exercise of locational market power. In addressing these issues it is

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[7] The approach of assigning FTRs would assign transmission rights to these customers, while the alternative approach would assign money, i.e. auction revenues, to these customers.

[8] There would be some complexities in allocating FTRs to LSEs serving load within constrained zones that are themselves embedded within constrained zones (such as San Francisco within the Bay Area zone). These complications can be managed, at least for point to point FTRs. Schedule 15 in the March 31, 2000 NEPOOL tariff contains one such allocation mechanism.

essential to start by recognizing that locational market power must be addressed, however one proposes to manage transmission congestion.

Ideally, there would be no locational market power, or it would be addressed in divestiture contracts, but that is not the case in California. It is therefore necessary to both reform the congestion pricing system and develop a mechanism for market power mitigation, long after the market has begun operation. The discussion below does not attempt to determine which generators possess market power, nor determine the dollar value of the bid caps that any generator possessing market power would be subject to. Instead, it describes a framework for mitigating market power that differs from that outlined by the CAISO in three important respects:

- It is intended to produce congestion prices that reflect demand and supply conditions, although necessarily imperfectly;
- It is intended to rely on financial incentives to motivate performance;
- It is intended to provide a transition to competitively determined locational prices.[9]

1. Market Power Mitigation Framework

The potential for the exercise of market power will be mitigated through the imposition of bid caps on generation owners possessing such potential market power. The generation owners subject to bid caps will be obligated to offer a specified quantity of power, located within a specified region, into the ISO coordinated day-ahead market at a price that is at or below a specified maximum price, the bid cap price. [10] The amount of capacity in each zone covered by bid caps would vary seasonally and by time of day.

The bid cap price could escalate over time and will fluctuate with fuel prices. The bid cap price will therefore have two components: a component that could escalate over time according to a predetermined formula and a component that would vary with a specified fuel price index.

The performance obligation associated with the bid cap will be financial. Entities subject to the bid cap will have a default bid in the day-ahead market equal to the bid cap quantity (or quantities) at the bid cap price(s). [11] The entity subject to the bid cap obligation could offer the bid cap quantity into the day-ahead market at a price lower than the bid cap but could not offer less than the bid cap quantity at a price less than or equal to the bid cap. If the bid cap quantity clears in the day-ahead market, the entity subject to

[9] The framework described below was developed in a collective process and reflects the contributions of many other individuals and entities. Earlier drafts of this framework further benefited from the comments of a number of individuals. Any errors in formulating and explaining this approach are, however, the responsibility of the authors.
[10] The energy could be offered directly through fixed schedules without adjustment bids or through bids submitted to the PX at prices consistent with the bid cap.
[11] As elaborated below, the entity subject to the bid cap might have an obligation to offer different quantities at different prices.

the bid cap will have a financial commitment in the day-ahead market and any imbalances between its real time output and its day ahead commitments will settle at real time LMP prices. The entity subject to mitigation would therefore have a financial incentive to take steps to make the power scheduled day-ahead available in real-time and could not financially benefit from withholding capacity from the market. Because the output would have been sold in the day-ahead market creating a financial obligation to deliver in real-time, an entity that failed to generate its scheduled output in real time would have to buy the withheld output at real-time prices.[12] Such a reduction in output would not raise the day-ahead prices at which the entity would have sold its output subject to bid caps, but would serve only to raise the cost of covering its day-ahead financial position.

Suppliers with bid cap obligations will be able to offer capacity in excess of their bid cap obligation into the day-ahead or real-time market at market based prices. Moreover, capacity subject to the bid cap in the day-ahead market that is offered into but not scheduled in the day-ahead market, can be bid into the real-time market at uncapped prices.

2. Market Separation

Under the proposed voluntary market separation requirement, market power mitigation would be implemented by requiring the entities subject to market power mitigation to either offer their capacity into the day-ahead market to support bilaterals without adjustment bids or to submit Inc bids at the bid cap price in the required amount into the CAISO day-ahead congestion management market. [13] This requirement would be mandatory for an entity subject to a bid cap. The Inc bids provided by generation subject to market power mitigation would be treated by the CAISO as an Inc bid available for pairing with the Dec bid of any scheduling coordinator meeting load within the LRA. Thus, any scheduling coordinator meeting load within the LRA in which generation is subject to market power mitigation could choose to allow its preferred import schedules to be adjusted down to create inter-scheduling coordinator trades with a scheduling coordinator subject to market power mitigation. Similarly, scheduling coordinators subject to market power mitigation would be required to allow their preferred generation schedule in the day ahead market to be adjusted upwards to the bid cap quantity at the locations covered by the bid cap. In such situations, scheduling

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[12] Another approach would be to structure these bid cap obligations as financial instruments, such as CFD options that would obligate the entity subject to the option to sell power to the CFD option holder in the day ahead market at the bid cap price. Such a structure would require a payment to the entity subject to the bid cap and these financial instruments could be auctioned.

[13] All of these provisions could be greatly simplified by a transition to conventional LMP based congestion pricing in the day-ahead market. The reality is that it is economically meaningful to cap energy bids, not adjustment bids. Adapting bid cap market power mitigation mechanisms to California's peculiar congestion pricing institutions greatly complicates market power mitigation and is a powerful incentive to move directly to LMP pricing in the day-ahead market.

coordinators' day-ahead schedules will be balanced in aggregate but may not be individually balanced. [14]

The scheduling coordinators whose preferred schedules are adjusted downwards by the ISO in the day ahead market based on their Dec bids and the bid-capped Inc bids of scheduling coordinators subject to market power mitigation would pay the Zonal Congestion Price to the bid capped supplier. [15] The Zonal Congestion Price would be calculated by adding a) the ISO determined day-ahead transmission usage charge to b) the lowest accepted decremental bid price of any scheduling coordinator whose day ahead schedule was decremented in the day ahead market. The ISO would pay the bid capped price to generation scheduled day ahead to provide intra-zonal congestion management. [16]

The effect of these pricing provisions is that all scheduling coordinators submitting price-capped bids would be paid the market clearing zonal price for all energy scheduled in the day-ahead market. It is the intent of these pricing provisions that if demand exceeded the supply that bid-capped suppliers were required to offer at the bid capped price, the market clearing price could be set by uncapped supply offers and these uncapped supply offers would determine the market clearing price paid to all sellers in the ISO-coordinated congestion management market as well as determining the price of transmission usage.

3. Supplemental Payments to Price Capped Bidders

The obligation to be subject to a bid cap may in some cases be accompanied by a supplemental payment to the price capped bidder. This would necessarily be the case if the expected revenues of the generation asset subject to the bid-cap were insufficient to recover the going-forward costs of that generation asset. If there is a supplemental payment to the entity subject to the bid-cap, then all entities with market power will have the opportunity to receive that supplemental payment and a bidding process could be employed to determine which entity would be subjected to the bid-cap obligation and

[14] Suppliers submitting dec bids for pairing with bid capped Inc bids would be permitted to submit an alternative adjustment bid to be used if the bid capped INC bids result in a higher adjustment charge. Thus, under the proposal different quantities of bid capped generation may be available at different prices. It is possible that while a scheduling coordinator might want to enter into an inter-scheduling coordinator trade if incremental generation is available at low bid capped prices, the scheduling coordinator might have better alternatives at the highest level of bid cap prices. The proposed mechanism would in effect allow scheduling coordinators to take advantage of bid capped supply when it is cheaper than their alternatives and to rely on their alternatives if those are cheaper.

[15] The Zonal Congestion Price concept is introduced to ensure that generators subject to market power mitigation would be paid the market clearing zonal price for the energy they generate, not merely their bid capped bid price.

[16] Thus, any generation within a zone that the ISO scheduled to operate in the day ahead market that would not be economic at the Zonal Congestion Price would be paid the difference between its Bid Cap Price and the Zonal Congestion Price. Any deviations between day ahead schedules and real time performance would be settled at real time LMP prices.

receive the payment. Only entities possessing market power would be eligible to receive such a payment in exchange for becoming subject to the bid-cap. [17]

4. Bid Cap Obligations

The bid cap obligation would pertain to a specified quantity of generation in each LRA. The bid cap obligation would be established on a one-time basis [18] and would impose an obligation on specific asset owners to bid to provide energy within a specific region. This obligation would be imposed only on generators potentially possessing market power.

The amount of capacity within each zone covered by the bid cap could escalate with forecasted load growth over a specified transition period. [19] The covered capacity would not escalate following the transition period and no new bid cap obligations would be imposed. The length of the transition period would be established such that LSEs would have the opportunity to arrange for the construction of new generation or the implementation of demand side management programs to meet load growth beyond the transition period. The length of the transition period might vary on a LRA by LRA basis.

Newly constructed capacity would generally not be subject to the bid cap. Entities subject to the bid cap could build new units and offer the capacity of the new units into the market to satisfy their bid cap obligation if the new capacity satisfied the locational requirements applicable to the bid capped capacity. There would be no bid cap on the generation required to meet load growth beyond the transition period and it would be the responsibility of LSEs or SCs to contract for generation to meet load growth beyond the transition period.

[17] Entities assumed to lack market power in the determination of the required mitigation would not be eligible to receive such a payment in exchange for becoming subject to the bid cap, because the presumption would be that these firms would bid competitively absent the bid cap. Thus, for example, if there were 1000MW of load in area A, 500 MW of transfer capability, 100 MW of generation owned by10 small producers, and 700 MW of capacity owned by generator B, it might be determined that generator B would be subject to bid caps on up to 420 MW of its capacity, under the assumption that the variety of small producers would compete. The 100 MW of generation owned by the 10 small producers would not be eligible to become subject to the price cap, because the market power analysis would have assumed that the small producers would bid competitively, and subjecting them to a bid cap would not change the need to subject 420 MW of capacity owned by generator B to the bid cap. Alternatively, if the 700 MW of capacity assumed above to be owned by generator B were instead owned by two entities, then the bid cap obligation could be divided between the two generators with potential market power.

[18] That is, the obligation for the current and future periods would be determined at the time that the market power mitigation system is implemented. The obligation of individual generators to supply energy at the bid-cap price would not be subject to year to year revision.

[19] Alternatively, the bid cap quantity required to be offered at each bid cap price might be fixed over the transition period, but the total amount of capacity required to be offered at bid capped prices could be set to be sufficient to meet expected load growth over the transition period.

The bid cap obligations would have a fixed duration but are intended to become irrelevant prior to their expiration as the bid cap price escalates over time or the market price comes to be set by the capacity of new entrants not subject to bid caps.

5. Bid Cap Price Determination

The upper limit on the level of the market power mitigation bid caps would be established based on the higher of the cost of a new generator or the going forward cost of an existing supplier. Within this general framework there would be multiple blocks of capacity subject to bid caps at varying price levels. [20] The bid cap price for a given capacity block would always be greater than or equal to the minimum load cost of the minimum load of that capacity block based on the initial heat rate. [21] The intent of this proposal is that the differing bid caps applicable to different blocks of capacity would mean that prices within transmission constrained regions would be lower when demand within the constrained region is low than when it is high, because higher demand would require the use of generation capped at higher prices. This would provide more efficient incentives for the construction of the right kind of generation capacity, the development of the right kind of load management programs, and the development of the right kind of transmission investments than a uniform bid cap price on all capacity that determined market prices within the constrained region whenever even a little congestion existed.

The calculation of adjustment bids and Zonal Congestion Prices would not take start-up costs into account. If the total revenues at the Zonal Congestion Price of any generators scheduled to operate to provide congestion management based on their bid cap were less than the sum of their start-up costs and bid capped energy cost, the generator would be compensated for the difference and this cost would be allocated to load within the zone.

Within this general framework, there are many fact specific issues that would require resolution. These issues would include the determination of going forward costs, the determination of the lowest cost alternative source of generation, and the allocation of fixed costs over both the expected lifetime and annual operating hours of the unit. Any determination of bid caps is therefore at best a rough approximation of a long-run competitive price and the bid cap will undoubtedly be too high at some times at some locations and too low at some times at some locations. A very important element of the market power mitigation proposal is that it provides a structured transition to a competitive market in which the bid caps do not always determine the market price.

[20] Thus, if there were 420 MW of capacity subject to bids caps during the peak hours in Zone A during July, 250 MW might have a bid cap of $50/MW, 100 MW have a bid cap of $75, 50 MW have a bid cap of $100, and 20 MW have a bid cap of $250

[21] All bid cap calculations would be based on the heat rate agreed upon at the beginning of the bid cap period, the initial heat rate. Improvements in unit heat rate performance would not result in a reduction of the bid cap price, nor would deterioration in unit heat rate performance result in an increase in the bid cap price. This would preserve the incentive of generation owners to make investments that maintain or improve the efficiency of their units.

Because the quantity of energy that must be offered into the day ahead market at bid capped prices would be fixed, rising demand would require that capacity be built and offered into the market at uncapped prices to meet the increases in demand. The bids submitted by the owners of this new capacity would not be capped.

6. Extra-ordinary Outage Conditions

There would be an additional set of bid caps that would be in effect during extra-ordinary transmission outage conditions. These bid caps would only be in effect in regions and during periods in which the transmission grid is operating outside the range of planning condition outages. These bid caps would be set at a higher level than the regular bid caps to encourage continued operation during adverse conditions.

7. Transitional Congestion Cost Sharing

If determined to be appropriate, a portion of the congestion costs paid to generators located within LRAs could be borne by customers located outside the LRAs during a transition period. If this transition adjustment were provided, the costs to be reallocated (RC) would be a specified fraction “X” of the product of the day ahead usage charge for the LRA * real time generation responsibility of each load within the zone. The costs to be reallocated would be calculated separately for each distribution company. The real time generation responsibility within the LRA would be equal to real time load minus the FTR or ARR allocation to that load. The reallocated costs (RC) would be allocated to all customers of the distribution company whose customers incurred the reallocated congestion costs.

The subsidy fraction (X) would phase out gradually over time. For example, X might be 80% in year 1, 70% in year 2, 60% in year 3, 30% in year 4 and 0% in year 5. The duration and phase out fraction could be tied to the transition period for market power mitigation and could vary by zone.

The treatment of all requirements and partial requirements wholesale customers could also be handled within this generation framework with appropriate adjustments for the specific contract and regulatory relationship.

It must be recognized, however, that any such adjustment would adversely affect the margin incentives of consumers, deter the development of load management programs, and reduce the incentive for loads to enter into long-term contracts for the output of new generators. It is therefore desirable that any such arrangement be very short-term transitional arrangements limited to the period before such investments in generation or load-management programs could be made.

8. Reserve Bid Caps

If the CAISO enforces locational reserve requirements within any of the LRAs, locational prices would also be calculated for these reserves. [22] Any entities possessing market power in the supply of reserves in these LRAs would be subject to bid caps covering the supply of reserves as well as energy and the bid cap quantity would be defined for the sum of energy and reserves that the entity would be required to offer into the day-ahead market. The bid cap for reserves would be the difference between the energy bid cap and the lower of the units actual incremental energy bid, or the minimum load energy cost used in determining the bid cap.

In addition, a reliability cost would be assigned to inadequate locational reserves within these regions. Any time inadequate reserves were available to meet the reserve target, the price of reserves would be set by the reliability cost of inadequate reserves and this reliability cost would also be reflected in the locational price of energy. [23]

III. CAISO EVALUATION OF THE REFORM COALITION PROPOSALS

The proposals we have set forth above are closely related to the proposals developed by the Reform Coalition during the stake-holder process. It is therefore appropriate to discuss the California ISO's evaluation of those proposals. In general, the CAISO's evaluation of the Reform Coalition's congestion pricing proposals reflects such a fundamental misunderstanding of the basics of congestion pricing under LMP that it suggests that no serious evaluation of LMP was undertaken.

A. CAISO Concerns

Appendix E to the CAISO's congestion management reform recommendations, "Congestion Management Redesign Options Not Adopted in the CMR Recommendations" contains a discussion of the congestion pricing proposals developed in the Stakeholder process by the Reform Coalition. In this Appendix, the CAISO identifies 8 considerations that presumably provide the basis for the CAISO's decision not to adopt the various elements of the recommendations of the Reform Coalition, in particular LMP pricing in real-time and point-to-point financial transmission rights that would be available in the form of both options and obligations.

None of the considerations discussed by the CAISO identifies an actual limitation of the Reform Coalition proposals or those we have described above. Instead, the CAISO's discussion demonstrates that the author of Appendix E does not understand the basics of congestion pricing under LMP and was therefore unable to provide a meaningful

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[22] It appears to be the case based on recent CAISO proposals that the CAISO schedules locational reserves in the day-ahead market to enable the CAISO to maintain reliability following various contingencies.
[23] The reliability cost would be fixed in advance but might either be a single number for all levels of locational reserve deficits or might vary with the degree of reserve inadequacy.

evaluation of the Reform Coalition proposals. Furthermore, there are fundamental contradictions regarding the nature of transmission congestion in California and the CAISO's proposed congestion pricing system both in representations within Appendix E and between Appendix E and the other documents describing the CAISO congestion management proposal.

1. Physical Characteristics of Western Grid Do Not Support Nodal Pricing

The CAISO states that one of its reasons for not adopting LMP is that "setting usage charges at the level of individual lines or buses, as proposed by the Reform Coalition, does not accurately reflect the binding constraints because such node-specific usage charges do not capture the larger area-wide effects on stability, security, reactive power, voltage support, and clearance requirements that define the constraints enforced by the operating engineers." [24] This statement implies a complete lack of understanding of LMP pricing. The fact that prices under LMP may vary by bus does not carry even the slightest implication that only bus or individual line constraints are or can be reflected in LMP prices.

Nodal prices vary by bus based on the differences in the cost of meeting load at those locations. Aside from differences in marginal losses, these differences arise when the transmission system is constrained and reflect differences in the impact of generation at each location on the binding transmission constraints. There is no requirement that these transmission constraints be limited to thermal limits on lines. This could be verified through even the most superficial review of LMP pricing in PJM and New York. One of the important transmission constraints in PJM is the Eastern interface. This is a voltage collapse limit, and the limit is defined by the sum of the flows over a group of 500kv lines. It is not a bus or single line level constraint.[25] Similarly, one of the more important transmission limits in New York is the Central East constraint. This is a voltage and stability limit. The limit depends on the configuration of the transmission system and the operating status of a number of generators and static var compensators. The limit is defined by the sum of the flows of a group of high voltage lines.[26] The reality, therefore is that LMP based congestion pricing systems routinely manage congestion associated with stability and voltage constraints and nomograms.

If the CAISO's development and evaluation of congestion management options was conducted under the impression that operating procedures and nomograms pertaining to branch groups, rather than individual lines or buses, cannot be reflected in an LMP

[24] California ISO Congestion Management Reform Recommendation, Appendix E, July 28, 2000 (hereafter CAISO E), p. 3.
[25] The PJM Eastern interface is comprised of the following facilities: Wescoville-Alburtis, Juniata-Alburtis, TMI-Hosensack, Peach Bottom-Limerick and Peach Bottom-Keeney 500 kV lines. The transfer limits are the sum of the flows, and are monitored as a single facility. The constraint ensures that no single contingency loss of generation or transmission will cause a voltage deviation greater than 5%. See PJM's "MAAC-ECAR-NPCC (MEN) Assessment Studies Procedure Manual," May 9, 2000.
[26] See Attachment 1 for the Central East nomogram.

pricing system or give rise to bus level differences in location pricing, [27] then its entire assessment of congestion management reform is demonstrably and fundamentally inadequate at a technical level and its conclusions should be disregarded. It is remarkable that the CAISO seems unaware of the basic concepts of locational pricing. Any misapprehensions the CAISO had about LMP could easily have been removed by a single conversation with the CAISO's own software developer, ABB, which has also developed some of the software for the NY LBMP pricing system.

Further, the CAISO asserts that the "Reform Coalition recognizes these limitations when it argues for dispatch-based pricing 'based on operator experience and superior knowledge of system characteristics...consistent with...maintaining reliability." [28] The CAISO asserts that this means that:

> …nodal LMP would, by necessity, always be subject to adjustment by operators. This is the case because the Coalition's proposal does not reflect many important physical constraints of the California transmission system. The ISO believes that it is far preferable to publish the nomograms and procedures actually used to manage LRAs, and to establish usage charges based on an explicit recognition of those actual area-wide constraints or flowgates. [29]

The CAISO statement again appears to reflect a fundamental lack of understanding of basic dispatch and LMP pricing concepts, as well as mischaracterizing the Reform Coalition proposal. Whatever transmission constraints, including nomograms and procedures, are actually used to manage transmission congestion within or between LRAs can readily be reflected in the calculation of LMP prices. If the nature of these constraints is such that all generation inside and all generation outside the LRA has the same impact on the constraint, then under LMP there would be a single price inside the LRA and a single price outside the LRA. If the impact of generation on the constraint varies depending on the generator location, such as a result of differences in effectiveness factors, [30] then the LMP prices could vary within the LRA.

The comment in the May 9 Reform Coalition statement that is cited by the CAISO actually referred to the dispatch process itself that the system operator would employ, rather than specifically to LMP pricing. The comment was merely making the point that

[27] CAISO E p. 3.

[28] Cited by CAISO at CAISO E p. 3. The actual unedited statement of the Reform Coalition was: "The ISO's objective would be to solve the balancing/security problem at the lowest as-bid cost (i.e. to clear the market) given the market participants' schedules and bids, in accordance with the market participants' bid instructions (see A above). Footnote 2: This is not a mechanical solution dictated by the ISO's model. It is recognized that system operators would use the model's solution as the general guide, but when required to ensure reliability they would also exercise judgment based on operator experience and superior knowledge of system characteristics. Within this operating framework, the ISO's objective would be a lowest as-bid cost solution, consistent with the bids and with maintaining reliability."

[29] CAISO E p. 4.

[30] These effectiveness factors are also referred to as shift factors or distribution factors. They reflect the differential impact of generation at different locations on a transmission constraint, whether the constraint is a single line or an interface.

there may be transmission constraints that are not reflected in the dispatch software but are instead implemented by the operators in real-time. Under the proposed LMP pricing system, these procedures would also be taken into account in calculating LMP prices. [31] LMP is capable of taking into account both constraints modeled day ahead and constraint values enforced only in real-time.

Overall, the CAISO's conclusion that the characteristics of the Western grid would not support LMP pricing is without foundation and indicates a lack of serious evaluation of LMP by the CAISO.

2. Commercially Significant Congestion

The CAISO's assertions regarding the inability of LMP to price commercially significant congestion again reflect a lack of understanding of the basic elements of LMP pricing. The CAISO states that: "pricing on the level of individual nodes or buses will fail to reflect some of those constraints because node-specific usage charges do not capture the larger area-wide effects on stability, security, reactive power, and voltage support that define the constraints that are of greatest importance during real-time operations." [32] This statement is not correct. Any constraint that can be modeled based on branch line flows or inter-zonal flows can be used to calculate LMP prices. Once again, it appears from these statements that the CAISO's examination and rejection of LMP pricing did not entail even the most basic discussions with software vendors.

Further, the CAISO asserts that "nodal pricing would attempt to establish separate prices for each of the thousands of separate buses on the grid, a level of granularity which bears no relation to the real-time operating practices of the actual system operators."[33] While it is true that LMP could result in market-clearing prices that differ at every location, the CAISO statement implies that LMP prices would always be different at every location. This is not correct. By definition, LMP pricing would only take into account the transmission constraints considered by system operators either in evaluating day-ahead schedules or operating the system in real-time. It should not be a difficult concept to understand that LMP prices are calculated based on the actual transmission constraints evaluated by the ISO, whatever those transmission constraints are. If all generators in a region have the same impact on a transmission constraint, then, abstracting from differences in losses, the LMP prices would be identical at those locations. Thus, if the transmission constraints monitored by the CAISO and the CAISO's operating practices actually treat two generator locations identically, then under LMP the prices would be identical at these locations.

[31] Obviously, however, if there are transmission constraints that are enforced in real-time that are not taken into account in determining day-ahead schedules, then day-ahead schedules may be infeasible in real-time, and could require that the ISO in effect buy-back the day-ahead schedules at real-time prices.
[32] CAISO E p. 4.
[33] CAISO E p. 4.

The CAISO further asserts that nodal pricing would " calculate transmission prices through the use of numerous computational and modeling assumptions built into 'optimization' software, and these assumptions would then be subject to modification based on operator judgment. The various assumptions that impact the final transmission price under such an approach are not transparent to the market."[34] Again, these statements are not correct. In reality, since the LMP prices would be based on the constraints taken into account by the CAISO in determining the feasibility of day-ahead schedules and operating the system in real-time, all of these assumptions and operator judgments would be those used by the CAISO to operate the system. The prices determined by LMP would therefore be no less transparent than the ISOs scheduling and dispatch decisions, but unlike the current prices used in California, the prices would be consistent with those scheduling and dispatch decisions. Further, if the CAISO were to make the applicable nomograms and operating procedures publicly available, [35] then both the dispatch and price determination would be transparent. If the CAISO actually operates the California transmission system consistent with the nomograms and operating procedures that it proposes to make publicly available, then market participants would be able to develop predictive models for transmission prices. Moreover, if the impact of generators on the transmission constraints described by these nomograms were identical for all generators within an LPA, as asserted by the CAISO, then the LMP prices would be identical. [36]

Importantly, there appears to be a fundamental misrepresentation underlying the CAISO comments regarding both the characteristics of the Western grid and commercially significant congestion. If the CAISO's representations were accurate, then it should be the case that the transmission constraints enforced by the CAISO would be consistent with its LRA and LPA definitions. In this circumstance, there would be no intra-zonal congestion, there would be no price differences within LRAs and LPAs under LMP, and energy injections and withdrawals at all locations within an LRA or LPA would be equivalent from a congestion management standpoint. The CAISO's own documents in the congestion management reform proposal, however, indicate that this is untrue. First, in the discussion of equity considerations (see also below), the CAISO indicates that there are internal constraints within the LRA areas that lead to differences in the cost of meeting load that can be in the range of several hundred percent. [37] This is inconsistent with representing that LMP would establish " a level of granularity which bears no relation to the real-time operating practices of the actual system operators." [38] If there are intra-LRA transmission constraints giving rise to differences in the cost of meeting load of several hundred percent, then LMP would provide a level of granularity that would be entirely consistent with the actual real-time operating practices of the system operators.

[34] CAISO E p. 4.
[35] CAISO E p. 4.
[36] CAISO E p. 4.
[37] CAISO E p. 5.
[38] CAISO E p. 4.

Moreover, as discussed further below, it is clear in the CAISO discussion of its congestion pricing proposal that rather than that proposal being "entirely consistent with the real-time operating practices of the actual system operators" the CAISO would base day-ahead congestion pricing on a "simplified commercial network model having one bus to represent each LPA." [39] The reality is that the CAISO's congestion management proposal perpetuates exactly the features that the FERC told the CAISO to fix last January, in particular the reliance on day-ahead market models that do not reflect the actual transmission constraints, resulting in infeasible day-ahead schedules. [40] Rather than letting market participants decide upon the level of transmission congestion that they find commercially significant, the CAISO appears intent on deciding for them the level of congestion it will ignore in the day ahead market and therefore have to pay to relieve in real-time.

3. Inequities

The CAISO's comments regarding the potentially inequitable impact of LMP on individual transmission customers not only fail to take account of important elements of the Reform Coalition proposal, but these comments indicate that the other statements by the CAISO regarding transmission constraints are materially inaccurate and misrepresent the nature of the transmission constraints evaluated by the CAISO.

First, the CAISO correctly observes that LMP prices may differ across customers because of differences in the past pattern of investment by the transmission owner. [41] This was also recognized by the Reform Coalition and by the proposals we have described above. The Reform Coalition's May 9, 2000 "Principles for Congestion Pricing Reform," and the proposals above specifically propose an equity allocation of FTRs to loads within transmission constrained regions of the existing zones. [42] The effect of this FTR allocation would be to shield the customers within the LRAs from the full financial impact of transmission congestion, allowing them to in effect pay the average cost of meeting their load.[43] Our proposals, however, would reduce the average cost of power to these loads, while distorting marginal incentives at little as possible. At the margin, these customers would pay the LMP price for incremental consumption, providing an incentive to reduce consumption when congestion makes energy expensive.

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[39] California ISO Congestion Management Reform Recommendation, July 28, 2000 (hereafter CAISO CM), pp. 30, 53-54., see also California Independent System Operator, Comprehensive Market Redesign, ISO Recommendation for Congestion Management Reform, August 24, 2000 p. 2,3.

[40] FERC Order, Docket No. ER00-555-000, issued January 7, 2000, p. 9. "…the ability of generators to create fictional congestion follows directly on another premise underlying intrazonal congestion management, i.e., that the ISO is required to accept all transmission schedules without verifying that all of those schedules are feasible. In accepting transmission schedules that bear no resemblance to physical reality, this congestion management scheme creates the opportunities for fictional congestion."

[41] CAISO E p. 5.

[42] Reform Coalition May 9, p. 7.

[43] Additional short-term cushioning could be provided to the customers of a particular distribution company through adjustments in the relative proportion of distribution costs borne by those customers.

Second, and more importantly, the CAISO's discussion of inequities indicates that the actual transmission constraints used to operate the transmission grid are not limited to LPA level constraints and operating procedures and nomograms that pertain to branch groups [44] but also include "localized constraints." [45] Rather than the actual set of transmission constraints being limited to the LPA level constraints that the ISO proposes to use to define zones, it is apparent from the CAISO's comments that the CAISO simply proposes to price some constraints and ignore others. [46] It is therefore not accurate to state that transmission constraints in the West are at the LPA or branch group level and the CAISO concedes elsewhere in its documents that this is not the case.[47] Thus, it is clear that the CAISO knows that under its LPA based transmission pricing system there will be intra-zonal congestion that is so serious that the CAISO believes that the cost of meeting load could differ by "several hundred percent" within these LPAs.[48] The new CAISO proposal therefore contains much the same problems as the current system: some of the actual transmission constraints that affect the dispatch and the cost of meeting load would not be taken into account in the pricing system, causing the prices to be inconsistent with the dispatch.

4. Market Separation

The CAISO retains a commitment to market separation in the day ahead market. This commitment to market separation may account for their resistance to pricing the actual transmission constraints in California in the day-ahead market, because the market separation requirement would likely be unworkable if the CAISO scheduled and priced use of the transmission grid based on the actual transmission constraints. Thus, according to the CAISO, the premise of the market separation requirement is that "Market Participants will develop the capability to organize themselves to efficiently trade with one another." [49] The operational problem is that a congestion management system based on balanced schedules without centralized coordination would be infeasible in a transmission system with many transmission constraints. On such a transmission system, every trade could affect dozens of potential constraints, which might or might not actually be binding, depending on the schedules of other market participants. In order for market participants to develop trades potentially affecting flows on dozens of potential transmission constraints, the market participants would need to trade dozens of interface FTRs and generator counter schedules, making even the simplest schedule change unworkable.

Moreover, in order for generators to provide redispatch options for a broad set of constraints through balanced schedules under a market separation requirement, dozens of

[44] CAISO E pp. 3-4.
[45] CAISO E p. 5.
[46] CAISO E p. 5. "Under an LPA-based pricing approach, however, since the relevant larger, area-based constraints are what is priced, customers that are located in the same regional market (i.e., located in the same LPA) are treated identically."
[47] CAISO E pp. 3-5.
[48] CAISO E p. 5.
[49] CAISO E. p. 5.

generators would need to be included in the portfolio. In order to make trading possible with such a market separation requirement, the CAISO is forced to pretend that there are only a small set of transmission constraints, despite the fact that it enforces additional constraints in actual operations. This discrepancy leads inexorably to the congestion management problems that confound the California market.

Rather than enabling market participants to manage congestion themselves, the CAISO pricing system and market separation requirement prevent market participants from managing congestion and ensure that congestion is managed on a command and control basis by the CAISO. Because the CAISO proposes that market participants manage congestion in the day ahead market based on a "commercial grid model" rather than the actual transmission constraints used to maintain reliability in real-time, market participants will inevitably be unsuccessful in managing congestion on their own. Similarly, because the market separation requirement limits the ability of generators to provide congestion management in the day-ahead market, day-ahead congestion prices and schedules will not reflect the actual transmission constraints and again defeat the ability of market participants to manage congestion.

The CAISO inaccurately asserts that "Centralized dispatch under the consolidated pool model results in a single joint price for energy and transmission transactions and eliminates the flexibility of participants in the consolidated pool markets to make their own resource optimization decisions."[50] Both parts of this statement are untrue. First, LMP can be used to define prices for energy and transmission that are consistent, whereas the prices developed by the California rules are often inconsistent.[51] That does not mean, however, that there are not separate prices for energy and transmission under LMP. Even a cursory review of the PJM or NYISO tariffs would reveal that there are separate prices for transmission service and energy.[52] Second, there is nothing about the way in which LMP produces consistent prices for both energy and transmission that in anyway "eliminates the flexibility of participant…to make their own optimizing decisions," as the CAISO claims. Instead, the reverse is true. The consistency of LMP transmission and energy prices and their efficiency enables market flexibility, because parties can be left to make choices that optimize their financial interests without compromising reliability or creating cost shifts.

The actual issues are quite different. First, should the CAISO impose artificial limitations on participation in the congestion management market through a mandatory market separation requirement? Second, should the ISO maintain a system that enhances the ability of market participants to game the transmission market under market separation?

[50] CAISO E p. 6.
[51] It is now generally understood that the value of transmission between any two locations is defined by the difference between the energy prices at those two locations. LMP recognizes this relationship between energy and transmission pricing, but this relationship is ignored in California.
[52] See, for example, NYISO OATT, Section II (Point-to-Point Transmission Service) and NYISO Services Tariff, Article 4 (Market Services: Rights and Obligations). See also PJM Open Access Transmission Tariff, Attachment K (Transmission Congestion Charges and Credits), Section 1.7.7 (Pricing).

On the first issue, the mandatory market separation requirement limits the ability of generators within the transmission constrained region to provide congestion management. Under the market separation requirement each customer within the potentially constrained region needs to match itself with a specific generator resource in order to provide adjustment bids in the day ahead market. This greatly thins the congestion management market compared to what would be available if generators within the transmission constrained region could offer redispatch in the day-ahead market to any entity willing to pay their bid price, on any path on which that the generator could relieve congestion. The outcome of this restriction is likely to be day-ahead inter-zonal congestion prices that are higher than the underlying differences in the cost of energy. California consumers and generators can no longer afford this level of inefficiency.

Moreover, the market separation principle has likely contributed to gaming of transmission constraints since 1999 with an increase in costs to consumers without any commensurate incentive for construction of new generation. The gaming in question is the submission of day-ahead schedules with adjustment bids in excess of expected real-time congestion (which may be zero) by scheduling coordinators holding FTRs on a branch path. The schedules can create congestion on the inter-zonal paths in the day-ahead markets that does not exist in real-time and would not exist absent the day-ahead schedules which do not flow in real-time. The submission of these day-ahead schedules is profitable if the entity submitting the schedules holds the bulk of the FTRs on the path and in particular has FTR holdings that exceed the amount of day-ahead scheduling required to create congestion in the day-ahead market. In these circumstances, the entity holding the FTRs pays congestion costs on the day-ahead schedules but thereby drives up the value of its FTRs.

These possibilities can be illustrated with a simple example. Entity A holds 100 FTRs from North zone to South zone and 100 MW is also the inter-zonal transfer capability used by the ISO on this path. Entity A submits a schedule to inject 90 in North zone and withdraw 90 in the South zone, with an adjustment bid of $50. If other market participants submit schedules in excess of 10 MW, there will be congestion. Market participants wishing to meet load in South zone with resources in North zone would be forced to either forego scheduling transmission use or pay $50/Mwh for transmission use. If market participants schedule 60MW of transmission use from North to South in the day-ahead market, Entity A would pay for 40MW of transmission use at $50/MW but would receive FTR payments on 100MW at $50/Mwh. In real-time, entity A does not either inject or withdraw and there is no inter-zonal congestion. By submitting the day-ahead schedules that did not flow in real-time, entity A would have generated $50/Mwh * 60 MW of congestion rent payments to its FTRs. In effect, entity A would have used its day-ahead schedules to withhold transmission capacity from the day-ahead market by in effect establishing a reservation price on this transmission.

There are several features of the mandatory market separation requirement that make this strategy particularly profitable. First, the mandatory market separation requirement makes it more difficult for generators in the South Zone that are willing to sell their output to other market participants for less than a $50 premium over the North zone price (thereby undercutting entity A's $50 transmission charge) to do so.

Second, the mandatory market separation makes it easier for the FTR holder to withhold transmission without having to accurately forecast locational prices or risk taking a position in the energy market.

Market participants that recognize the existence of congestion day-ahead and the lack of congestion in real-time could submit adjustment bids that take them out of the day-ahead market whenever congestion existed, but under California rules, these entities would be penalized for buying in the real-time market rather than day-ahead.

California cannot afford artificially high congestion costs associated with the mandatory market separation requirement whether they arise from limitations on participation in the congestion management market or the costs imposed on generators and loads by gaming.

The CAISO asserts that the end point of the Reform Coalition proposals would be "the mandatory application of centralized dispatch."[53] The reality is that the policies we and the Reform Coalition have described would provide greater choice for market participants and while eliminating the artificial restrictions imposed on participants in the California market.

5. Relative Efficiency of Centralized Dispatch

The CAISO Appendix E contains a series of assertions regarding the CAISO's inability to use centralized dispatch programs. All of these comments appear to apply to day-ahead unit commitment programs. [54] The issue raised by the Reform Coalition proposals was simpler. If there are transmission constraints that the ISO enforces in its day-ahead schedules or real-time operations, then those constraints should be reflected in the price of transmission service. If it is correct that market participants are able to completely solve the congestion management problem through bilateral scheduling, then the CAISO should be able to accommodate all day-ahead, and hour-ahead schedules as well as real-time usage. If, on the other hand, this is not the case and the ISO finds it necessary to curtail transactions or redispatch generators in order to manage transmission congestion, then the bid-based cost of managing that congestion should be reflected in transmission prices.

No matter how hard or easy centralized dispatch is, if the CAISO proposes to redispatch generation two-days ahead, day-ahead, hour-ahead or in real-time to manage transmission constraints, then the CAISO is engaged in centralized dispatch. In performing this centralized dispatch, the CAISO has some model of the transmission constraints that is sufficiently good to keep the lights on in California. If the CAISO redispatches the system to maintain reliability, then that redispatch ought to be least cost based on bids,

[53] CAISO E p. 6.
[54] CAISO E p. 7.

and transmission prices ought to be consistent with the CAISO's dispatch decisions, and vice versa. If the CAISO model is good enough to manage reliability, then it is good enough to determine prices.

The CAISO's aversion to pricing all of the transmission constraints that it proposes to manage two-day-ahead, day-ahead, hour-ahead and in real-time is hard to understand. It is possible, of course, that accurately pricing the systems operators' actual dispatch would make transparent any serious inefficiencies or inconsistencies in the operators' dispatch decisions. We assume that this would not pose a problem for the CAISO.

6. Price Signals

The CAISO asserts in its evaluation that its proposal is superior to the Reform Coalition proposal because the CAISO's pricing proposal "sets usage charges only for transmission per se, thus establishing prices for using precisely the transmission facilities that the ISO is responsible for allocating." [55] LMP based pricing systems in New York and PJM are of course able to set transmission usage charges so it can hardly be the case that LMP pricing precludes setting transmission usage charges.

The CAISO argues that the LMP approach is flawed because the "fundamental locational signals are the usage charges for transmission over congested paths." [56] The CAISO does not, however, explain the basis for this remarkable statement. Consider, for example, the decision of an industrial customer in a constrained region about whether to operate or not at a given level of congestion. Is the fundamental signal that needs to be provided to the industrial customer the difference in price relative to another zone or the price of power to the locational customer? Conversely, consider the decision of a generator located in a constrained region as to whether it wishes to increase output to reduce congestion. Is the fundamental signal that needs to be provided to that generator the difference in price relative to another zone or the price that will be paid for the generator's power? The answer in both cases is that for short-term congestion management it is the price that matters.

The CAISO proposals for procurement of local reliability services implicitly recognize that energy procurement and pricing cannot be separated from transmission allocation and pricing. The proposed two-day-ahead market, which the CAISO would use to manage a substantial amount of congestion, is not described as a transmission market *per se*, but rather a process by which the CAISO can centralize the unit commitment process for enough generation within each LRA to ensure that these generators will schedule enough energy inside each LRA to relieve any congestion within and into each LRA. While this is explicitly an energy procurement and pricing process, it is also indirectly a process for allocating transmission usage. Thus, the bids in this process are energy (or capacity) bids, rather than the adjustment bids the CAISO uses in its day-ahead and hour-ahead markets to allocate transmission, but the purpose is the same.

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[55] CAISO E p. 8.
[56] CAISO E p. 9.

In effect, therefore, the CAISO is proposing to create new forward energy markets, while maintaining the fiction that is operates only transmission markets in the forward time frame. It proposes to use these forward energy markets not only to solve local reliability problems but also to manage congestion, so that it can preserve the market separation fiction in its transmission markets. Apparently, the CAISO Staff has concluded that its system operators could not successfully manage the congestion between its new LRAs and the current zones using adjustment bids in the day-ahead and hour-ahead markets, because the market separation rule would seriously restrict its ability to find redispatch options. In other words, the added costs of creating, operating and using the CAISOs proposed new energy markets would be imposed on California participants so that the CAISO can preserve the fiction that it uses adjustment bids to manage congestion.

7. Competition with Scheduling Coordinators

The CAISO apparently takes the view that for the CAISO to manage transmission congestion based on energy bids, rather than adjustment bids, in the day-ahead market would entail the CAISO conducting “forward energy markets in competition with the Scheduling Coordinators” and “would be problematic.” [57] Apparently the reason the CAISO feels that such a congestion management strategy would be problematic is that the CAISO’s monopoly status places it in a favorable position and that such a day ahead congestion management market would not “contribute to the development of vigorous and competitive energy markets.”

The reality is that the proposals described above, and previously set forth by the Reform Coalition, rely on competitive energy markets to manage congestion. The CAISO 2-day-ahead market on the other hand, would largely supplant competitive energy markets, as the CAISO would become the main energy buyer, in effect buying high, selling low and recovering the difference in uplift. Instead of coordinating transmission usage based on the bids of loads and generators the CAISO proposes to manage transmission congestion based on the supply bids of generators and the CAISO’s demand. The reality is that under the CAISO proposal, markets would have little or no role in congestion management.

All of the CAISO rhetoric about facilitating management of congestion in forward markets,[58] is meaningless given the fundamental realities that the CAISO is the only buyer in the 2-day-ahead market, and that the day-ahead market in which market participants transact is based on a commercial network model that does not reflect the actual transmission constraints.

8. Point to Point FTRs

[57] CAISO E p. 9.
[58] CAISO E p. 10.

The CAISO argues that the introduction of point-to-point FTRs would introduce unnecessary complexity into the ISO's approach to locational pricing, but it does not explain what the complication is or why it would arise.[59] The CAISO argues that under its approach point-to-point FTRs would be redundant because if shift factors were fixed, market participants could attempt to assemble a portfolio of interface FTRs that was equivalent to point-to-point FTRs. The CAISO did not, however, explain how this would be possible if the actual shift factors are not fixed. [60] Moreover, the CAISO did not explain or show the process by which market participants could buy and sell interface FTRs in a bilateral market so as to arrive at an efficient set of congestion cost hedges.

As discussed in the accompanying evaluation of the CAISO proposal,[61] the reliance on interface by interface FTRs for hedging will greatly complicate trading because of the large number of FTRs needed to hedge a transaction, and the contingent value of the FTRs. Moreover, the obvious unworkability of interface FTR based hedges when there are material number of constraints, forces the CAISO to pretend that there are few transmission constraints. As a result, the CAISO would again be in the position of accepting schedules and holding transmission customers harmless against real-time congestion when those schedules are actually not feasible on the ISO coordinated grid, once again forcing the CAISO to buyback the infeasible schedules at real-time prices. Rather than solving the problems the FERC pointed to in its January 7,2000 order, the CAISO proposal exacerbates these problems

Moreover, the CAISO asserts that long-term FTRs raise fundamental issues because "an FTR defined point-to-point or LPA-to-LPA includes insurance against changes in the grid configuration and resulting changes in the shift factors" associated with transmission investments.[62] This may be a characteristic of the CAISO proposal, but it is not as such a characteristic of the reform coalition proposal. The Reform Coalition proposal would require transmission expanders whose projects reduced the ability of the transmission grid to accommodate existing FTRs (by increasing or decreasing shift factors) to absorb the financial consequences of the impact of their transmission project. The guarantee to FTR holders under the Reform Coalition proposal was that if there are transmission investments made that reduce transfer capability associated with the outstanding FTRs, then the cost of that reduction in transfer capability will be borne by the transmission investor, not the FTR holder.

B. Unaddressed Issues

While, as the CAISO notes, the CAISO's congestion management proposals reflect a few elements of the Reform Coalition proposals, there are a number of important elements of

[59] CAISO E p. 12.
[60] The CAISO proposal is vague on whether, and how often shift factors will be updated, leaving it as an open issue in Sections 7.2.5 (p. 44) and 8.1.8 (p. 57).
[61] Scott Harvey, William W. Hogan, Comments on the Congestion Management Proposals of the California ISO, August 31, 2000, pp. 17-19.
[62] CAISO E p. 13.

the Reform Coalition proposals, and those we propose above, that were neither critiqued nor adopted by the CAISO.

1. Financial rights as obligations or options

The Reform Coalition has proposed that financial transmission rights be defined as both obligations and options, and that both types be made available to market participants in an auction. [63]

CAISO FTRs are exclusively options. There is therefore no value in the forward markets to counterflow and no mechanism to trade it. An FTR option from A to B is entirely distinct from an FTR option from B to A and the acquisition of A to B FTR options does not support the sale of additional B to A FTR options, or obligations. Forward market scheduling based exclusively on FTR interface options will materially underschedule use of the transmission grid in a system with loops. FTR obligations would sell at a discount relative to FTR options reflecting the value of any counterflow associated with the FTR obligation.

2. Transmission Pricing that Reflects the Cost of Incremental Losses

The Coalition has proposed that energy, ancillary service and transmission pricing reflect the cost of incremental losses. [64]No basis has been provided for California consumers to continue to subsidize high cost imports or, in recent times, subsidize energy exports.

3. Establishment of a Trading Hub

The Coalition has proposed that the CAISO facilitate the development of one or more internal California trading hubs, analogous to the PJM Western Hub[65] by defining the locations composing the hub, posting the hub price, and allowing the sale of FTR options and obligations to and from the hub.

IV. Conclusion

The problems in the California congestion management system can be resolved, using the same LMP pricing systems that have solved similar congestion pricing problems in other regions. The difficulties arising from the reality that we must start with the CAISO's current pricing rules and software and operate the market as we reform the congestion pricing system complicate the transition. They do not, however, change the direction in which reform must move, they only change how long it will take to get to the end point and perhaps some of the interim steps along the way. The mitigation of locational market power is in many respects a harder problem to solve, but it is also possible to

[63] Coalition May 9, March 30, p. 14
[64] Coalition May 9, March 30 p. 14.
[65] Coalition March 30 # 13 p. 14,

identify the direction in which reform must move and the necessary structure of those reforms.