CALIFORNIA ISO

California Independent
System Operator

January 14, 2004

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

Re: California Independent System Operator Corporation
Docket No. ER02-1656-017
December 16, 2003 Notice of Technical Conference

Dear Secretary Salas,

Pursuant to the Federal Energy Regulatory Commission's December 16, 2003 Notice of Technical Conference and December 24, 2003 Notice of Extension of Time issued in the docket noted above, the California Independent System Operator Corporation ("ISO") hereby submits its responses to the requests for information contained in the December 16, 2003 Notice of Technical Conference.

The ISO has posted these responses on its web site and sent these responses to all parties in Docket ER02-1656

If you have questions about these responses, please contact Lorenzo Kristov at (916) 608-7129

Respectfully submitted

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cc. Parties in ER02-1656

Clarification of CAISO Market Design Issues
In Response to December 16, 2003 Notice of Technical Conference

It its December 16, 2003 Notice of Technical Conference, the Commission requested that the CAISO clarify the following four issues in a written filing, so that interested participants may both respond and better prepare for discussions at the MD02 Technical Conference to be held on January 28-29, 2004. The present document constitutes the CAISO's response to this request. For each of the four questions, the CAISO first re-states the Commission's request as stated in the Notice, and then provides the relevant paragraph from the Commission's October 28, 2003 Further Order on the California Comprehensive Market Redesign Proposal. Following these quotes the CAISO provides its response.

Question 1. Clarification of the CAISO's approach to allocation of marginal losses – refer to ¶ 78 of the October 28 Order.

> 78. We find the CAISO's proposal to add over-collection of losses to the CRR Balancing Account and its method of allocating the surplus revenues reasonable. However, while we find the CAISO's proposal to return the surplus revenues to load reasonable, it is unclear how the CAISO will compensate an entity that self provides for losses under the CRR Balancing Account. As a result, we will direct the CAISO to clarify how the allocation method would apply to self-schedules.

CAISO Response. In the July 22, 2003 filing on the Comprehensive Design Proposal the ISO described how transmission losses would be incorporated in the nodal prices, and thus would be provided optimally by all supply resources that submit bids through the optimal dispatch of the Integrated Forward Market. Under this approach, it will not be possible for SCs to self-provide losses explicitly. Rather, SCs can self-provide losses in an approximate way by self-scheduling additional supply in excess of their demand to supply their estimated loss obligation. As stated in the July 22, 2003 filing, paragraph 72:

> 72. With losses so internalized [in the nodal prices], it will not be possible for SCs to self-provide losses explicitly,[1] though this can be accomplished by another means in the forward markets. Specifically, the SC can estimate the amount of losses it will be responsible for and self-schedule additional supply to cover the estimated losses, using the payment for the excess supply to offset the cost of losses. Depending on the location where the SC self provides to cover losses, this payment may be more or less than their share of the cost of losses procured optimally and priced through LMP. While this method may not be precise in each hour, over time the amount of losses should become predictable by the SC with reasonable accuracy.

Based on the above, SCs who attempt to self-provide losses in this manner would receive direct compensation through the energy payments for the excess generation at appropriate locational prices, and thus there would not be any need to treat them any differently from other market participants with respect to the distribution of balancing account funds. The following example illustrates how this would work.

[1] SCs will be able to self-provide losses explicitly in Phases 1B and 2. The issues discussed in this section apply only to Phase 3 [implementation of LMP].

This example makes the following assumptions, and considers two scenarios described below.

- There two SCs; each has a generation and a load in its portfolio. SC_1 has generation G_1 to serve 100 MW load L_1 while SC_2 has generation G_2 to serve 50 MW load L_2.
- As shown in Figure 1, the network has sufficient transmission capacity and therefore there is no congestion. (By removing the factor of congestion, the effect of losses alone can be studied.)
- The average generation loss factors are 2% for G_1 and 1% for G_2. It is assumed that the average generation loss factors represent the actual percentage of losses.
- The marginal generation loss factors are 4% for G_1 and 2% for G_2. Marginal generation loss factors are consistent with the definition of locational marginal prices, because such prices reflect the cost of serving an additional MWh of load at each location, including the costs of transmission congestion (though there is no congestion in this example) and losses. At the same time, incorporating these marginal loss factors in the LMPs causes over-collection of losses.
- <u>Scenario 1:</u> SC_1 self-schedules balanced generation and load, i.e., $G_1 = L_1 = 100$ MW, without considering losses. SC_2 self-schedules 50 MW of load, i.e., $L_1 = 50$ MW, and bids 60 MW of generation G_1 for $30/MW.
- <u>Scenario 2:</u> SC_1 self-schedules $G_1 = 102$ MW and $L_1 = 100$ MW in order to self provide for losses. SC_2 self-schedules 50 MW of load, i.e., $L_2 = 50$ MW, and bids 60 MW of generation G_2 for $30/MW

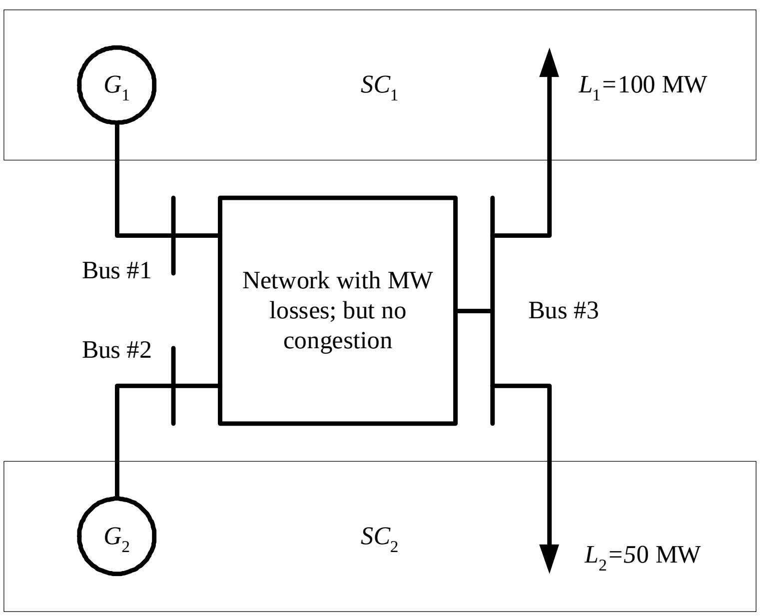

Figure1. A congestion free network with losses

Scenario 1: SC_1 covers transmission losses through the market.

In this Scenario, SC_1 self-schedules balanced generation and load, i.e., $G_1 = L_1 = 100$ MW, without considering losses. SC_2 self-schedules 50 MW of load, i.e., $L_2 = 50$ MW, and bids 60 MW of generation G_2 for $30/MW. The dispatch outcome is shown as in Table 1.

Table 1: Optimal Dispatch of Scenario 1

SC	Bus	Resource	Bid Price	Bid Quantity	Dispatch	LMP (λ)	Resource Charge (+) / Payment (-)	SC Loss Charge (+) / Payment (-)
1	1	G_1	Fixed	100 MW	100 MW	$29.39/MW	-$2939	$122
	3	L_1	Fixed	100 MW	100 MW	$30.61 MW	$3061	
2	2	G_2	$30/MW	60 MW	52.53 MW	$30/MW	-$1575.9	-$45.4
	3	L_2	Fixed	50 MW	50 MW	$30.61 MW	$1530.5	

The optimal schedule of G_2 is determined as follows. According to the average loss factors, the total loss of the system is ($0.02*G_1 + 0.01*G_2$). Therefore, the power balance requires the following:

$$(G_1+G_2) - (0.02*G_1 + 0.01*G_2) = L_1 + L_2$$

i.e.,

$$0.98*G_1 + 0.99*G_2 = 150 \text{ MW}.$$

Since G_1=100 MW, G_2 = 52.53 MW.

The LMPs at the three buses are determined as follows:

- G_2 is the marginal unit; the LMP for G_2 is set by its bid at $30/MW, i.e., λ_2 = $30/MW.
- The LMP for Bus #3, i.e., for L_1 and L_2, is determined by dividing the LMP of G_2 by the penalty factor (which is based on the marginal loss factor) of G_2 as follows:

$$\lambda_2 = \lambda_3 - \lambda_3 \frac{\partial P_{loss}}{\partial G_2} \Rightarrow \lambda_3 = \lambda_2 / (1 - \frac{\partial P_{loss}}{\partial G_2}) = 30/(1-0.02) = 30.61$$

- The LMP for G_1 is determined by multiplying the LMP at bus 3 by the penalty factor (which is based on the marginal loss factor) of G_1

$$\lambda_1 = \lambda_3 - \lambda_3 \frac{\partial P_{loss}}{\partial G1} = 30.61*(1-0.04) = 29.39$$

As is shown in Table 1, SC_1 pays $122.00 for loss and SC_2 collects $45.40 for providing the loss. The total amount of over collection of payment for loss is: (150*30.61 - 100*29.39 - 52.53*30) = $76.60. This amount of over-collection is put into the CRR Balancing Account to help ensure full compensation to CRR holders. Any funds remaining in the CRR balancing account at the end of the year will be allocated to the TRR (Transmission Revenue Requirement) accounts of the Participating Transmission Owners (PTOs) in proportion to each PTO's annual TRR. This allocation to the TRR accounts reduces the Transmission Access Charge (TAC) rates that the loads pay. Therefore, the loads collectively receive the residual of the over-collection for transmission losses through the lowered TAC rates.

It is difficult to predict how much of the over-collection for losses is returned to a specific load (whether it is self-scheduled or not) for several reasons. First of all, a portion of the over-collection of losses may be used to pay for shortage of congestion revenue for CRR entitlements. (For example, a shortfall in congestion revenues relative to CRR payments can occur in an hour when an unplanned transmission system outage or de-rate results in less available transmission capacity than was included in the CRR allocation and auction process.) Secondly, the residual of the over-collection for losses is distributed to the TRR accounts based on the TRRs of the PTO, which are not necessarily proportional to loads. Thirdly, the load that receives more benefit from a lowered TAC rate might not be the load that paid more for losses.

Scenario 2: SC_1 self schedules additional generation to cover losses.

In this Scenario, SC_1 attempts to self-provide for losses by scheduling more generation than load in its portfolio. Specifically, SC_1 self-schedules the following amount of generation and load: G_1 = 102 MW and L_1 = 100 MW based on the average loss factor of 2% for G_1. SC_2 self-schedules 50 MW of load, i.e., L_2 = 50 MW, and bids 60 MW of generation G_2 for $30/MW. The dispatch outcome is shown as in Table 2.

Table 2: Optimal Dispatch of Scenario 2

SC	Bus	Resource	Bid Price	Bid Quantity	Dispatch	LMP (λ)	Resource Charge (+) / Payment (-)	SC Loss Charge (+) / Payment (-)
1	1	G_1	Fixed	102 MW	102 MW	$29.39/MW	***-$2,997.78***	***$63.22***
	3	L_1	Fixed	100 MW	100 MW	$30.61 MW	***$3,061.00***	
2	2	G_2	$30/MW	60 MW	50.55 MW	$30/MW	***-$1,516.50***	***$14.00***
	3	L_2	Fixed	50 MW	50 MW	$30.61 MW	***$1,530.50***	

The optimal schedule of G_2 is determined as follows. According to the average loss factors, the total loss of the system is ($0.02*G_1 + 0.01*G_2$). Therefore, the power balance requires the following:

$$(G_1+G_2) - (0.02*G_1+0.01*G_2) = L_1 + L_2$$

i.e.,

$$0.98*G_1 + 0.99*G_2 = 150 \text{ MW}.$$

Since G_1=102 MW, G_2 = 50.55 MW. The LMPs at the three buses are determined as before.

As is shown in Table 2, SC_1 pays $63.22 and SC_2 pays $14 for losses. The total amount of over collection for losses is $77.22. This amount of over collection is put in the CRR Balancing Account and distributed as described in Scenario 1.

Conclusions

A comparison of the results of Scenario 1 and Scenario 2 shows the following:

1. SCs can self-provide losses by self-scheduling more generation than load. However, if the SC does this by self-scheduling to meet its estimated average losses, the amount of excess generation will not cover the cost of marginal losses. In this example, SC_1 schedules 2 MW more generation than the load (based on its average loss factors), but only reduces its loss charge from $122 to $63.22 rather than completely eliminating it.
2. The total over-collection of payment for losses in Scenario 2 is actually greater than that in Scenario 1. The reason for this is that the IFM optimization optimally dispatches generation to cover losses, thus it is not optimal for SC_1 to self-provide for losses.

How the Eastern ISOs Deal With Marginal Losses

Both ISO-NE and PJM use marginal losses via the mechanism of marginal loss penalty factors in their calculation, dispatch and settlement processes. Use of marginal losses produces excess revenues in the congestion funds, and the re-allocation of these revenues is a topic of on-going discussion. Neither ISO-NE nor PJM offers an explicit loss self-provision feature. In theory a generator could self-schedule additional output to cover its estimated losses. In these markets, however, self-scheduling means that the resource becomes a price-taker in real-time dispatch, foregoes start-up and no-load payments, and is not eligible for uplift payments. Moreover, while the resource can self-schedule the approximate MW quantity, it may not be able to accurately predict the dollar amount, which makes this a less desirable option. NYISO also uses unscaled marginal losses in all calculation, dispatch and settlement processes, and does not provide for loss self-provision. As in the other Eastern ISOs, there is an over-collection of loss revenue.

Question 2. Revised pricing mechanism for setting prices for constrained output generators in the forward market – refer to ¶ 89 of the October 28 Order.

> 89. Each of the Eastern ISOs has developed mechanisms that allow non-dispatchable units to set the market clearing prices in the day-ahead market. This ability is absent in the current filing. The Commission is concerned that the present CAISO proposal to limit the ability of Constrained Output Generators to set the clearing price in the forward markets is not consistent with its approach to real-time pricing and may prevent the convergence of prices in these markets. We direct the CAISO to review its approach to setting prices in the forward market and develop a pricing mechanism for Constrained Output Generators that is consistent with its approach to real-time pricing (i.e., a constrained-output generator can set the market clearing price for those dispatch intervals in which any portion of its output is needed to serve real-time load) and promotes the convergence of prices in the forward and real-time markets.

CAISO Response. In this response the CAISO provides its rationale for proposing not to allow constrained output generation to set forward market prices. CAISO staffs are still considering the question of how to design an alternative pricing mechanism, consistent with the Commission's direction as stated above, that also addresses the concerns described in the paragraphs below. The CAISO will be prepared to discuss this topic further at the Technical Conference.

Concerns About Allowing Inflexible Generation to Set Market Clearing Prices

To be clear, the CAISO understands "Constrained Output Generation" to be generating resources that cannot be dispatched continuously across their entire operating capacity because, due to physical operating constraints, they can only operate at a limited number of discrete operating levels, in some cases only at their maximum operation points or not at all.[2] The term "lumpy generators" is often used to describe such generating resources. In the July 22, 2003 filing the CAISO proposed not to allow such generation to set prices in the forward markets because to do so would be inconsistent with the definition of "marginal" prices and would have a significant undesirable consequence in the day-ahead market with respect to CRR settlement.

According to classical marginal pricing theory, a resource's bid price does not set the LMP if its output is constrained by a physical operating limit. Typically, if a generator's output hits the

[2] The Commission's October 22, 2003 Order on CAISO Tariff Amendment No. 54 (paragraph 70) defines Constrained Output Resources as "generating resources that cannot easily or economically change load levels and are typically restricted to generating at their full capacity for their unit-specific minimum run time."

upper limit, it means that additional, more expensive generation was needed and therefore the LMP is usually greater than its bid price. Conversely, if a generator's output hits the lower limit, it typically means that not all lower cost generation was fully utilized and therefore the LMP is usually lower than this unit's bid price. The issue at hand is about whether to deviate from the classic marginal pricing theory and allow a "lumpy" generator that sits at an upper limit to set the LMP. (Such a price may more accurately be referred to as the "LAP", or "locational administrative price", since such a price does not correctly reflect the marginal cost of energy at the location.) The example below shows that setting the LAP instead of the LMP can cause damaging inconsistency between the actual direction of congestion and the nodal price difference.

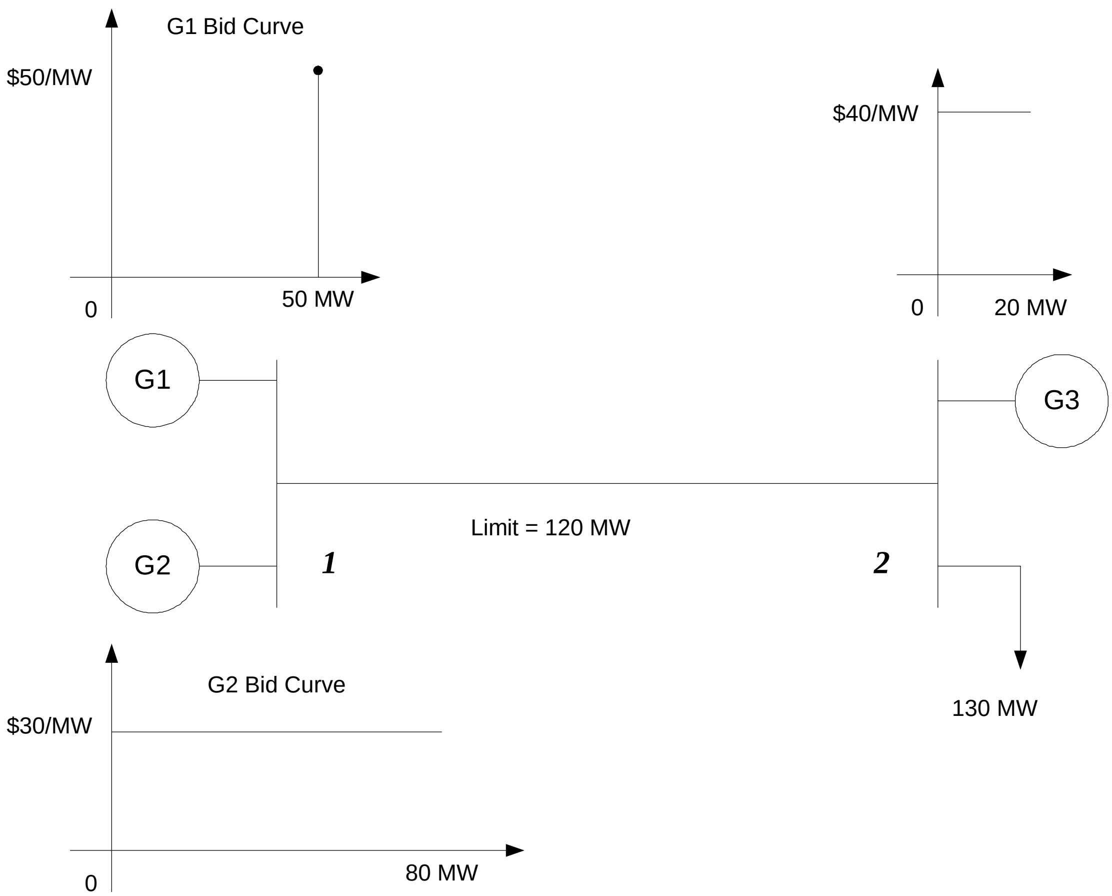

Figure 2. Inconsistency between lumpy nodal prices and congestion direction

Consider the example as shown in Figure 2. The transmission limit from Node 1 to Node 2 is 120 MW, There are three generators serving the 130 MW of load.

G_1 is a "lumpy" generator that has to provide 50 MW at $50/MW once it is committed.

G_2 is a "flexible" generator that can provide 0 MW to 80 MW at $30/MW.

G_3 is a "flexible" generator that can provide 0 MW to 20 MW at $40/MW.

Since G_2 and G_3 alone are not sufficient to meet the 130 MW of load, the lumpy generator G_1 has to be turned on to produce 50 MW. Since G_2 is cheaper than G_3 and the transmission limit is 120 MW, G_2 produces 70 MW to maximize the use of the transmission line; and G_3 produces the final 10 MW needed. According to classical marginal pricing, the LMPs are $30/MW at node 1 and $40/MW at node 2. If the "lumpy" generator G_1 were allowed to set the price, the nodal price at node 1 would be $50/MW. Consequently, while the congestion is from Node 1 to Node 2, the nodal price difference would reflect congestion in the opposite direction.

With obligations-type CRRs as proposed by the CAISO, the inconsistency between pricing and congestion patterns, as described in this example, can be very problematic. In a system like that of Figure 2, Market Participants who acquire CRR obligations from Node 1 to Node 2 to hedge against anticipated congestion costs would be charged in their CRR settlement for congestion in the opposite direction, even though the actual congestion is in the direction they anticipated. Of course, this adverse impact on CRR settlement applies only to the day-ahead market, since CRR settlement will be based on day-ahead nodal prices under the CAISO's proposal.

The inconsistency between pricing, dispatch, and congestion patterns, as illustrated in this example, also creates perverse incentives that are contrary to prudent operating practices and may pose a threat to system reliability. In the example, generator G_2 would see a nodal price that is higher than its bid, yet would have 10 MW of available capacity that was not dispatched and would want to increase its output to earn the $50 price. Thus the CAISO could be paying SCs to cause congestion and overload the transmission system. Moreover, the erroneous price signals would also provide incorrect information in the economic analysis of generator siting and transmission expansion efforts.

Ultimately the problem derives from the fact that we are trying to satisfy several objectives that are not fully mutually consistent. First, the CAISO wants LMPs to express the cost of serving the next MW of load at the location, according to the formal definition of marginal prices. Second, the CAISO wants the prices to reflect such costs in a realistic manner, by incorporating all the generation that must be dispatched to serve the load. When lumpy generation is needed to serve load, these two objectives come into conflict, because the mathematical optimization requires marginal generators to be continuously dispatchable above and below their optimal operating points, and hence will exclude lumpy generation from setting prices.[3] Third, the CAISO wants settlement for CRRs (in the day-ahead market) to be consistent with the actual pattern of congestion. If the CAISO allows lumpy generation to set day-ahead prices we compromise this objective. Fourth, the CAISO wants to send meaningful real-time price signals to encourage forward scheduling of load and real-time demand response. This would argue for allowing lumpy generation to set prices in real-time (as the CAISO proposed and the Commission approved for Phase 1B). Fifth, the CAISO does not want to create impediments to convergence in prices between forward and real-time markets. For the reasons described above, all of these objectives are not simultaneously achievable. The CAISO submits that the approach proposed in the July 2003 filing represents a reasonable balance among these objectives.

How the Eastern ISOs Treat Lumpy Generators

In the day-ahead markets of ISO-NE and PJM, the lumpy resource is allowed to set the price if it would have had a non-zero dispatch as a flexible resource. In real-time, such a resource would set the price only if its economic dispatch as a flexible resource is close enough to its lumpy operating point to make it eligible for setting the ex-post price. Otherwise, it will be a price taker in the real-time market.

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[3] A way around this could have been to ignore the lumpiness of the resource and dispatch it in the forward market as if it were fully flexible. But this would result in accepting an infeasible resource schedule, which would compromise one of the fundamental objectives of the MD02 effort, i.e., to establish feasible schedules in the forward markets.

Thermal resources with minimum up and/or down times of more than an hour are considered inflexible resources in real-time and are not eligible to set the ex-post nodal LMP, but if they are pool-scheduled in the day-ahead market, they would be eligible for daily uplift consideration.

In the NYISO markets, lumpy generators are called “Fixed Block Units.” They are allowed to set the price (in the day-ahead market if scheduled in the day-ahead, or in the real-time market if dispatched in real-time) if they are in economic order in the sense that turning them off would require scheduling or dispatching a higher cost resource. The lumpy generators are not allowed to set the real-time price if they are running because of minimum run time requirements.

3. Further clarification of the statement by the CAISO that it “does not prohibit energy from capacity committed in the day-ahead RUC from being sold by the unit owner via any bilateral transaction in the hour-ahead market, including sales to other Control Areas” – refer to ¶ 123 of the October 28 Order.

> 123. … We note that, in its transmittal letter, the CAISO makes the statement that it “does not prohibit energy from capacity committed in the day-ahead RUC from being sold by the unit owner via any bilateral transaction in the hour-ahead market, including sales to other Control Areas.” The Commission finds this statement to be contrary to the proposal as the CAISO has described it elsewhere in its filing.[4] This statement seems to indicate that units, once committed, are actually free to sell elsewhere, i.e., not committed. We request further clarification of this aspect of the CAISO’s proposal.

CAISO Response. In the July 22, 2003 filing the CAISO assumed that capacity procured in the day-ahead RUC procedure would be allowed to bid and schedule in the hour-ahead market and bid into the real-time market, to be dispatched in these markets to serve load. The hour-ahead market, however, is open to out-of-state buyers and exporters who may bid in this market and purchase energy for export in real time. If the hour-ahead market clears by accepting some quantities of both in-state and out-of-state demand, and energy from both RUC and non-RUC capacity, there is no way in such a market to link the RUC capacity to either in-state or out-of-state demand. The CAISO therefore concluded that a prohibition on hour-ahead energy sales for export by RUC capacity would not be enforceable.

There are at least three ways to address this problem. One way would be to include an estimate of hour-ahead exports in the day-ahead RUC procurement target. At the time of the July 2003 filing the CAISO anticipated that the procedure for setting RUC procurement targets would incorporate previous days’ experience in order to minimize both over-procurement and under-procurement. Including estimated hour-ahead net exports in the procedure would be consistent with such an approach, and remains the CAISO’s preferred solution to the problem.

An alternative approach would be to require RUC capacity (except for minimum load energy) to remain unscheduled up to real time, to operate only in response to a real-time CAISO dispatch instruction. The CAISO does not prefer this option, because it would render RUC capacity unavailable for purchase by in-state load in the hour-ahead market, and thus would undermine the purpose of RUC (i.e., to ensure adequate capacity is available to meet control area load).

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4 In its filing the CAISO states that in the event that the day-ahead market closes significantly below the CAISO’s load forecast and does not commit adequate resources to meet that forecast, the RUC process provides a reliability backstop for the CAISO to commit additional supply resources if needed to meet the system load forecast and reserve requirements. [Reference to ¶ 98 of the July 22, 2003 filing.]

Moreover, because load bidding into the hour-ahead market could not avail itself of this RUC capacity under such a restriction, much of the RUC capacity would likely be redundant. Establishing accurate day-ahead RUC procurement targets would become more complicated, and would likely lead to over-procurement of RUC capacity to the extent in-state demand bids clear against supply bids from non-RUC capacity in the hour-ahead market.

A third approach would be to eliminate the hour-ahead market, but in discussions with market participants during the original MD02 design sessions in Spring 2002 and the working groups in Fall 2002, participants were virtually unanimous in support of retaining the hour-ahead market.

The issue raised by this question is extremely important for understanding the rationale for the CAISO's proposed RUC design. In particular, it is important that capacity designated in day-ahead RUC be available for purchase by load in the hour-ahead market. The ability of buyers to optimize their procurement between the day-ahead and hour-ahead market has been a feature of the California design since the beginning, and participants want to continue to rely on the ability to trade close to real time through a transparent formal market, and to schedule such trades and thus minimize their exposure to real-time prices. At the same time, a design that has this RUC capacity bidding energy into the hour-ahead market distinguishes it from the typical Ancillary Service product (e.g., Operating Reserves) that, in contrast, represents an unloaded capacity product that must remain fully available for real-time dispatch by the CAISO.

4. Additional clarification on the ISO's concern that a purchase of only capacity may undermine incentive to imports to acquire transmission capacity across ties as part of the residual unit commitment process – refer to ¶ 127 of the October 28 Order.

> 127. We accept the CAISO's capacity procurement target as proposed. However we reject, without prejudice, its proposal to procure energy in the RUC Process. It is the Commission's understanding that the RUC process provides a reliability backstop for the CAISO to commit additional supply resources if needed to meet the system load forecast and reserve requirements. We believe the CAISO is capable of meeting its load forecast through the RUC process without the procurement of energy. The RUC process should be a method for obtaining adequate capacity, not energy, to meet the system load forecast because by purchasing the capacity the CAISO will have the energy associated with those capacity resources available to them in the subsequent market, at the prevailing market price, if needed to meet their load forecast. We note, however, that the CAISO raises a concern that a purchase of only capacity might not give sufficient incentive to imports to acquire the necessary transmission capacity across the ties. The CAISO may submit additional clarification on this point.

CAISO Response. In the July 2003 filing (transmittal letter, page 90, footnote 112) the CAISO offered the following rationale for purchasing energy from import suppliers in the day-ahead RUC procedure:

> The CAISO's proposal to procure energy from imports, not capacity, is intended to conform better with the scheduling practices in the WECC. In particular, suppliers importing energy need to line up transmission capacity outside of California in the day-ahead time frame. In the WECC region, most units are committed in advance of the next operating day. The CAISO's proposal to acquire import supply needed to meet unscheduled but forecasted demand in the day-ahead time frame is consistent with this approach. The CAISO is dependent on imports, and the CAISO's proposal facilitates

import participation by accommodating it in a manner that is consistent with general practices in the West. Finally, the CAISO is concerned that if import suppliers only had a commitment from the CAISO for capacity, that might not be sufficient incentive for them to acquire the necessary transmission capacity (or might otherwise result in an inefficient use of transmission capacity).

The CAISO offers the following further explanation in response to the Commission’s question. The underlying problem is similar to the one described in response to the previous question in that it goes to the issue of the nature of the obligation placed on resources procured in RUC. With regard to the present question, the issue is more complicated due to the fact that the CAISO is an import-dependent control area and therefore cannot, for a substantial share of the operating hours of the year, meet its internal load without import supplies. In this context, even if a capacity commitment in RUC would be sufficient incentive for an import supplier to acquire the necessary transmission capacity, it would still not guarantee that the energy would be available for the CAISO in real time. Under the CAISO’s RUC proposal as filed in July 2003, out-of-state market participants may still sell their energy to other parties or into other markets before real time. To guarantee real-time energy availability from such imports, the capacity commitment from the CAISO would have to be secured with a binding obligation on the supplier to have the associated energy available for the CAISO in real-time at a pre-specified bid price. In effect this would be a call option for energy, and would require a substantial reservation fee. In addition to the potential to dramatically inflate RUC procurement costs, such an approach may provide perverse incentives for importers to raise their day-ahead energy bids so that they are selected in RUC rather than in the IFM, in order to capture the additional revenue of the capacity reservation fee.