CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: October 14, 1999

Re: ***Market Analysis Report***

This is a project status report. No Board action is required at this time.

This memorandum summarizes key market conditions, developments, and trends for the month of September and the first week of October. Our attached Weekly Market Reports provide more detailed information.

KEY MARKET CONDITIONS FOR SEPTEMBER 1999

In the California Energy Markets

- System loads were moderate for most of September with the exception of the few last days of the month. Maximum daily loads averaged just under 34,000 MW during the month. System loads reached 36,000 MW during only 30 hours all month, and peaked over 40,000 MW during only one hour on September 29.

- The ISO's real-time energy market was split zonally during about one-third of the hours in September due to congestion on Path 15. During peak hours, the ISO real-time imbalance price in NP15 averaged $44.97/MWh, while imbalance prices in SP15 averaged $40.47/MWh. During off-peak hours, the ISO real-time imbalance price in NP15 averaged $32.99/MWh, while off-peak imbalance prices in SP15 averaged $33.09/MWh.

- In the PX day-ahead market, unconstrained energy prices averaged $33.91 during September. Day Ahead interzonal congestion on Path 15 caused constrained PX prices to differ between NP15 and SP15 about 58% of the time during September. During the month, constrained PX prices for NP15 and SP15 averaged $43.03/MWh and $33.89/MWh for the peak hours. During off-peak hours, constrained prices in the PX averaged $30.86/MWh and $20.06/MWh, respectively.

In the Ancillary Service Markets

Day Ahead Ancillary Service Prices

- The ISO's Ancillary Service markets were split zonally during 100 hours in September, or 14% of the time, due to south-to-north congestion on Path 15. As a result, prices in NP15 tended to exceed prices in SP15. In the regulation market, prices for downward regulation exceeded prices for upward regulation during the first full month since the ISO began pricing these two products separately on August 17. The following table summarizes A/S prices weighted by zonal quantities for August and September:

	August 1999		September 1999			
	Peak	Off Peak	Peak		Off Peak	
	NP15 & SP15	NP15 & SP15	NP15	SP15	NP15	SP15
Reg*	12.77	12.96	-	-	-	-
Reg Up	26.46	6.46	16.04	11.49	15.22	10.18
Reg Down	12.28	14.60	23.19	11.19	31.23	16.77
Spin	10.14	0.96	7.77	8.30	2.12	0.85
Non Spin	4.78	0.10	5.41	2.43	1.21	0.10
Replace.	6.50	0.00	5.40	3.12	0.01	0.01

* Prior to August 18 there was a single price for both reg up and reg down.

Ancillary Service Costs

- Despite the need to procure Ancillary Services zonally during many hours, the average cost of Ancillary Services declined again in September, averaging approximately $1.0 million per day, or about 4.3% of the estimated overall cost of wholesale energy. We attribute the lower costs mainly to the combination of three factors: moderate loads, savings from separate pricing of upward and downward regulation, and implementation of the Rational Buyer software and protocols.

  High prices experienced in the A/S markets during the last three days of September accounted for $9.8 million in A/S costs or about one-third of the monthly total.

Month	Avg. Daily Cost* (Millions)	Avg. Cost per MWh of System Load ($/MWh)	% of Energy Costs*
July	$ 1.8	$ 2.59	8.1%
August	$ 1.3	$ 1.85	5.3%
September	**$ 1.0**	**$ 1.52**	**4.3%**

*** Includes Day Ahead and hour-ahead procurement costs**
**** Energy cost = actual hourly loads multiplied by the PX Day Ahead Unconstrained MCP.**

In the Congestion Management Markets

- Day-ahead congestion frequency on the northwest paths were slightly lower in September than levels experienced in August. Day-ahead congestion occurred on COI in 53% of peak hours and 34% of off-peak hours. Day-ahead congestion charges on COI ranged from $.01/MW to $187/MW and averaged $11.28/MW. Day-ahead congestion occurred on NOB in 8% of peak hours and .4% of off-peak hours. On NOB, day-ahead congestion charges ranged from $.01/MW to $18/MW and averaged $4.31/MW.

- September congestion patterns on the southwest paths were higher than August levels. There was little difference in the frequency of off-peak congestion on the Eldorado branch group (40% for September versus 42% in August); however, congestion occurred in about 22% of peak hours versus last month's rate of 4%. Off-peak charges on Eldorado ranged from $.01/MW to $22/MW and averaged $7.36/MW.

- Path 15 experienced significant congestion during both peak and off-peak hours (south to north) with congestion occurring in 43% of peak hours and 85% of off-peak hours. Day-ahead congestion charges on Path 15 ranged from $.11/MW to $104/MW and averaged $16.79/MW.

SUMMARY OF MARKET CONDITIONS FOR THE FIRST WEEK OF OCTOBER 1999

The ISO raised price caps in the ISO Ancillary Services, Real-time Balancing Energy and Congestion Management Adjustment Bid markets from $250/MWh to $750/MWh on Scheduling Day September 30 for Operating Day October 1. This section provides a preliminary summary of market conditions and events immediately following the increase in price caps. One week does not provide enough experience for us to draw definitive conclusions about the impact of the price cap increase on the ISO's markets and other energy markets. A more detailed analysis of market performance after the price cap increase will be provided in our November Report.

<u>Congestion Markets on October 1, 1999</u>

The ISO's experience on the first Scheduling Day with higher price caps (scheduling day September 30 for Operating Day October 1) was generally higher prices in all the markets. The price increase was most pronounced in the day-ahead congestion market. The congestion usage charge for four hours (hours ending 10, 19, 20 and 21) was in the range of $690/MWh on Path 15 (south-to-north) and in the $660/MWh range for imports on COI. This resulted in an average constrained PX price for NP15 of $218/MWh and a maximum price of $725/MWh for hours ending 10, 19, 20, and 21.

The high congestion costs of October 1 resulted from a combination of factors:

- ***Expectations of high loads and real-time energy prices*.** The Operating Day of October 1 was preceded by several days of unseasonably high loads, during which prices in the real-time market repeatedly hit the $250 price cap. For the last two days of September, total system loads during peak hours (ending 7 through 22) averaged about 35,000 MW, and exceeded the ISO's day-ahead forecast by an average of over 2,000 MW, or about 5.5% of total system loads. On October 1, loads moderated and the trend of higher-than-expected loads was reversed, with peak hour loads falling short of the day-ahead forecast by an average of about 5.5%, or over 1,680 MW.

- ***De-rating of Path 15**.* On Scheduling Day September 30, Path 15 was de-rated (down to 900 MW) for Operating Day October 1 due to a combination of scheduled maintenance and a de-rating of Diablo Canyon Unit 1. Under the Remedial Action Scheme (RAS) for Path 15, the available transmission capacity of Path 15 was reduced due to the de-rating of the Diablo Canyon unit. The ISO is investigating the timing of scheduled maintenance on Path 15 since a delay of a few days following the increase in the price caps may have allowed the market to transition more smoothly to higher price cap levels.

- ***Thinness of Supply of Adjustment Bids for Incremental Energy in NP15.*** During hours ending 8 through 22, there were only about 1,000 MW of adjustment bids for incremental energy within NP15 that could be used to manage inter-zonal congestion. During these hours, virtually all adjustment bids for incremental energy within NP15 were accepted. However, these supply bids were sufficient to meet only about half of the required adjustments in day-ahead schedules within NP15 necessary to resolve inter-zonal congestion. The remaining adjustments in day-ahead schedules necessary to resolve congestion came from adjustment bids for decrementing demand scheduled in NP15.

- ***Pricing of adjustment bids for decrementing loads in NP15***. As noted above, the thinness of the supply of adjustment bids submitted by generation units created an unusually high demand for adjustment bids for decrementing load scheduled in the day-ahead market within NP15. On October 1, a significant portion of these demand-side adjustment bids were priced unusually high relative to the maximum potential price for energy in the real time market ($750). We attribute the high price of these adjustment bids to expectations that there was a high probability that the real-time prices could go to $750/MWh on Operating Day October 1, given that prices hit the $250 cap during the previous two operating days. However, as noted above, loads actually moderated on October 1 with peak hour loads falling short of the day-ahead forecast by an average of over 1680 MW, or about 5.5% of total ISO load. After October 1, the market corrected itself with more rational bidding of demand-side adjustment bids based on expectations of conditions in the real-time market and the impact of adjustment bids on final prices paid the PX Day Ahead market.

<u>Market Trends and Conditions from October 1-7</u>

- During the first week of October, the real time market continued to experience zonal splits. The real time market was split between SP15 and NP15 a total of 60 hours for the first seven days of October (or 42% of all hours). Average real time prices for NP15 were $61/MWh while SP15 prices averaged about $31/MWh.

- Unconstrained PX prices averaged about $50/MWh and $33/MWh for peak and off-peak periods, respectively. Constrained PX prices after congestion management for the peak period averaged $91.16/MWh for NP15 and $40.59/MWh for SP15. For off-peak hours, constrained PX prices averaged $41.02/MWh for NP15 and $29.61/MWh for SP15.

- The ancillary service markets were procured zonally due to congestion on Path 15. The day-ahead market for regulation up was split zonally for all hours during the week of October 1-7. As a result, regulation up prices for NP15 and SP15 averaged $118/MW and $15.49/MW, respectively.

- Zonal procurement for the other ancillary service markets occurred as well, though to a lesser degree, throughout the first week of October. Day-ahead NP15 prices for the regulation down, spin, non-spin, and replacement averaged $21.57/MW, $23.13/MW, $8.01/MW, and $25.90/MW, respectively, while SP15 prices averaged $16.77/MW, $13.27/MW, $3.41/MW, and $4.34/MW, respectively.

- Congestion patterns during the first week of October remained similar to the last week of September. For the Day Ahead market, the Path 15 branch group experienced 145 hours of south-to-north congestion during the first week of October (a rate of 86%), while imports on COI experienced a congestion rate of 40% during then same period. Path 15 and COI experienced very high congestion prices on October 1 as well, reaching maximums of $698/MW and $678/MW, respectively.

ISSUES UNDER INVESTIGATION

- ***Mitigation of Intra-zonal Congestion in the Absence of Workable Competition.*** The current procedure for Intra-zonal Congestion Management (AZCM) in the absence of workably competitive market conditions is subject to gaming and has not been adequately addressed in the past. This has become a critical issue for Market Operations, and key to several market redesign and market improvement projects. Lack of adequate treatment of AZCM under non-competitive market conditions was also a primary factor that led to the rejection of the Board's New Generation Interconnection Policy (NGIP) by FERC. Resolution of this issue is the primary line of defense the ISO is using in its request for Rehearing on NGIP. It is also a prerequisite for some redesign projects (*e.g.,* Portfolio Bidding and Inter-SC trades of Adjustment Bids) under discussion with the Stakeholders in the Market Redesign 2000 (MR 2000) forum. At present, the ISO relies on RMR units to resolve Intra-zonal Congestion when there is no workable competition. With the plan to reduce reliance on the RMR units, other measures must be put in place to deal with the problem. The new Out-of-Market (OOM) payment protocols approved by the Board in August present an alternative to the use of RMR. The DMA supports use of RMR and OOM protocols for mitigation of intra-zonal congestion in the absence of workable competition.

- ***Mitigation of Potential Abuse of Out-of-Market Protocols (OOM).*** At its August 26 meeting, the ISO Board approved the new OOM payment protocol, including a provision enabling a Market Participant to select either the existing or the new OOM payment method separately for each of its resources on December 31 of each year for the following year. The New OOM protocol has several attractive features such as meeting reliability needs and mitigating gaming in intra-zonal congestion management. There might be rare circumstances when the OOM price provides a small incentive for capacity withholding, if relied upon frequently. In evaluating OOM we feel the benefits far outweigh the potential risk. DMA will monitor for this risk and propose mitigation if necessary. These measures could include limiting the eligibility of a resource to elect the new OOM protocol if the number of OOM calls on the resource exceeds a reasonable threshold, or if strategic withholding is observed.

- ***Support Market Redesign 2000 (MR 2000).*** The DMA is actively participating in the MR 2000 stakeholder process. The DMA proposed a number of criteria to evaluate the market impact of the MR 2000 proposals. The criteria include reduction of market power and gaming potential, increased market efficiency, reduction of barriers to entry, increased supply or depth of market, reduced cost to end-use consumers, and avoidance of unintended impacts on other markets. The main MR 2000 projects under review include:

  Mitigation of Large Uninstructed Deviations (UID): Two complementary elements for reducing the magnitude and adverse impacts of UID were proposed: more rigorous enforcement of the original 10-minute dispatch design of the Imbalance Energy Market, and 10-minute settlement for UID (which to date have been settled at the hourly *ex post* price). One effect of the first element, 10-minute dispatch, will be to reduce and ultimately eliminate preferential treatment of resources that cannot respond to 10-minute dispatch instructions due to technical limitations or inadequate Control Area coordination. One concern mentioned by some market participants is that this approach ignores the limitations of these resources, dispatching them and settling with them as if they could respond to 10-minute dispatch instructions (including charges for replacement reserve and no-pay penalties) and may result in reduced participation. DMA does not see the 10-minute requirement as a barrier to entry. Market participants can still bid into this market. They may bid higher prices since now they must incorporate any costs incurred if they generate uninstructed for the other 50 minutes of the hour. Thus the market may equilibrate at higher prices, although that isn't a necessary outcome.

There may be less demand for the higher-quality stack as some constrained resources move to forward markets and attract additional load to those markets, or there might be additional high-quality supply in real time as participants invest in the technology to respond to 10-minute price signals. The DMA will monitor the market impact of the 10-minute dispatch and 10-minute settlement proposals, and will continue to participate in the UID subteam to resolve the design and implementation issues associated with these proposals.

Portfolio Bidding and Inter-SC Trades of Adjustment Bids: This project initially involved a bundled set of components, including Portfolio Bidding, Inter-SC Trades of Adjustment Bids, Simplified Network Model, and FTRs based on Network States. The DMA supports Inter-SC Trades of Adjustment Bids, as this will deepen the adjustment bid market and lead to greater efficiency of Inter-Zonal Congestion Management (RZCM). The DMA pointed out potential gaming with Intra-zonal Congestion Management (AZCM) that would be exacerbated by Portfolio Bidding. The DMA also pointed out that the proper use of network state as a simplified model had nothing to do with FTRs. Instead, it was an implementation option in the case a simplified model was decided to be desirable. As a result, we included resolution of AZCM gaming as a necessary feature in this project and dropped the concept of network-state-related FTRs. The DMA is collaborating in defining the details of the proposal to ensure all potential market power and inefficiency concerns are properly addressed and mitigated.

A/S CONG Integration: The DMA considers integration of Congestion Management and Ancillary Services Procurement functions an important step in improving market efficiency. A/S CONG integration would have to break new algorithmic ground to preserve the Rational Buyer A/S procurement procedure. The DMA is investigating this issue. This project is, at present, on the second-level priority list of the stakeholders and the ISO, partly due to the implementation complexity.

Directional A/S Procurement in case of Congestion: The DMA has evaluated directional procurement of A/S when there is forward market inter-zonal congestion. We recommend an alternative approach, which is essentially what the ISO is doing now. When there is inter-zonal congestion, the ISO would first conduct the A/S auction system-wide using Rational Buyer. If the results of this auction were feasible (i.e. did not exacerbate the congestion or even created a counter-flow), the A/S so procured would already utilize all low-cost bids and reflect an efficient market outcome. Alternatively, if the system-wide auction were infeasible, the ISO would procure A/S zonally, and in this case the proposed directional procurement would not be able to offer an improved outcome. An additional problem with the proposed directional procurement is that it would yield two different prices to suppliers in the same zone depending on where their A/S bid is used. Different prices to suppliers would lead to adverse changes in bidding behavior by rewarding the high bidders in the constrained-in zone. We therefore recommend continuing with systemwide procurement utilizing counter-flows as allowed by congestion.

The DMA will continue its collaboration with the MR 2000 team to ensure consistency among design changes, to identify potential unintended or undesirable impacts, and to recommend improvements where appropriate. This policy issue is covered comprehensively in a separate October Board memo prepared for the MI/ADR Committee.

- **FTR Affiliate Information Disclosure.** At the August 26 meeting, the Board did not reach consensus regarding the imposition of position limits on FTRs. In addition, the motion prohibiting position limits also failed. The issue was referred back to the MI/ADR Committee for resolution. During a teleconference meeting on September 7, the MI/ADR Committee decided not to impose position limits at this time. However, the Committee did approve requiring disclosure of affiliate information to facilitate monitoring of FTR concentration and potential capacity withholding. The DMA helped develop the Q3 Tariff language as well as the information disclosure procedure to accommodate this new requirement. The DMA is also implementing provisions in the design of its FTR Market Monitoring System (MMS) to facilitate tracking of FTR concentration by affiliate groups as well as by Owner and SC.

- **Support New Generation Interconnection Policy (NGIP) Rehearing.** The DMA has actively participated in the Rehearing pleading with the FERC to address concerns of market power with the NGIP. DMA has supplied arguments, backed by numerical examples, to show that the "single flaw" basis on which the FERC rejected the NGIP proposal does not exist. The examples point out that the ISO would not rely on market bids to resolve intra-zonal congestion when there is no competitive market. They show that intra-zonal mitigation performed by the ISO allows the New Generator to limit its payment for intra-zonal congestion to a level that would prevail in a competitive market.

- **Investigation of Customer Complaint Related to ISO's Modification of Published Real-time Prices.** The DMA received a complaint from one Market Participant that the ISO occasionally modifies the real-time *ex-post* price after it has been published. The DMA investigated the problem and provided a response through the Market Participant's Client Services representative. There are circumstances under which ISO may have to adjust the real-time price. This is to a large extent because, at present, dispatch is conducted manually based on the merit order determined by the BEEP stack. The dispatch data is then entered manually for price computation. Correct price computation requires timely and error-free entry of manual dispatch instructions that have been accepted by the dispatched entity. There may be data entry errors; miscommunication may occur between the dispatcher and the SC or field personnel; a resource in the BEEP stack may decline the dispatch order that the dispatcher assumed would be accepted and entered into BEEP as such; etc. Therefore the prices posted are subject to change as errors are detected and corrected. ANALOPE will be important in reducing the errors once it goes into operation.

- **Studies Ordered by FERC.** DMA has the lead on evaluating the efficiency of ancillary services procurement based on capacity bids only or capacity and energy bids (referred to as the two-part bid). This study is one of several ordered by the FERC in its October, 1997 Order. The studies are due at the end of November, and DMA will present them at the November Board meeting.

- **Public Release of Bid Data.** The DMA has the lead on developing a proposal for release of ISO market bid data to the public. In doing so we have assessed improvements to market efficiency, market power concerns, recent FERC rulings on the New York and PJM ISOs, and ISO cost and implementation issues. This policy issue is covered comprehensively in a separate October Board memo prepared for the MI/ADR Committee. Management's recommendations on this subject will be presented to the Board this month.