California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: November 3, 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 October. Our attached Weekly Market Reports provide more detailed information.

KEY MARKET CONDITIONS FOR OCTOBER 1999

In the California Energy Markets

- Unseasonably warm weather in October resulted in total system energy loads of 19,955 GWh --- only about 1% less than September 1999, and 11% higher than October, 1998. Daily peak loads averaged 32,175 MW, roughly 12% higher than October, 1998 peak loads. The peak load for the month occurred on October 1, reaching 36,672 MW.

- Prices in both the ISO's Real-Time energy market and PX Day-Ahead market were marked by separate constrained prices in NP15 and SP15 during many hours due to congestion on Path 15. As shown in the table below, average real-time energy prices were nearly 50% higher in NP15 than SP15, while constrained PX energy prices were about 10% higher in NP15 than SP15. Prices in the PX Day-Ahead market were split zonally due to congestion on Path 15 during 74% of hours in the month, while the ISO's real-time market was split zonally during about 35% of hours in October.

Energy Price Summary for October 1999

	System Average	NP15	SP15	Pct. Hours of Zonal Pricing
Real Time Price				
Peak	$ 61.80	$ 73.72	$ 49.87	35%
Off-Peak	$ 32.51	$ 37.30	$ 27.72	36%
Total	$ 52.01	$ 61.55	$ 42.47	35%
PX Constrained				
Peak	$ 54.38	$ 64.38	$ 44.37	76%
Off-Peak	$ 34.74	$ 38.58	$ 30.89	69%
Total	$ 47.81	$ 55.76	$ 39.87	74%

- Prices in the PX Day-Ahead and ISO's Real-Time energy markets tracked closely throughout the month in peak and off-peak hours. As shown in the preceding table, real-time prices in SP15 averaged $42.47 compared to an average constrained PX price of $39.87. In NP15, real time prices averaged $61.55 compared to an average constrained price in the PX of $55.76

- Prices in the both the ISO real-time and PX Day-Ahead markets were substantially higher in October compared to the same month last year. Real time prices exceeded average prices during October of last year by about 65%, while PX prices rose by about 79% compared to October, 1998.

- The increase in PX and real-time energy prices in October 1999 compared to October, 1998 can be attributed to a number of factors, including: (1) higher loads; (2) less energy from relatively low-cost hydro and nuclear sources in California; (3) increased reliance on higher-cost thermal units; (4) the need to procure energy zonally during many hours due to congestion on Path 15; and (5) an increase in the ISO's real-time energy price cap from $250 to $750.

- As shown in the table below, the average total Final Hour-Ahead Schedules in October, 1999 exceeded those in October, 1998 by about 12%. At the same time, total generation scheduled from hydro and nuclear sources decreased by a total of about 1,558 MW, or about 5% of total average Hour-Ahead Schedules. These two trends required an increased in generation scheduled from thermal units of about 58% compared to October, 1998.

Generation Source – October 1998 and 1999

	Average Hourly MW*		Difference	
Generation Source	**Oct-98**	**Oct-99**	**MW**	**Percent**
Hydro	2,676	2,246	-430	-16%
Nuclear	4,375	3,247	-1,128	-26%
Coal	1,348	1,276	-72	-5%
Other Reg. Must-Take/Must Run	5,194	5,139	-55	-1%
Other Thermal	5,933	9,389	3,456	+58%
Imports	6,492	7,773	1,281	+20%
Exports	-1,586	-1,658	-73	+5%
	26,018	29,069	3,051	+12%

* Based on final Hour-Ahead schedules Oct. 1-27 during 1998 and 1999.

- Although prices in the real-time market or PX never hit the new $750 price cap taking effect in October, prices exceeded the previous $250 limit during 14 hours in the real-time market, while constrained PX Day-Ahead prices exceeded $250 during 9 hours in October.

In the Ancillary Service Markets

Ancillary Service Prices

- The ISO continued to procure the bulk of A/S in the Day-Ahead market, with an average of about 75% to 83% of A/S being procured in the Day-Ahead market. The following table summarized weighted average prices in October, 1999 in both the Day-Ahead and Hour-Ahead markets.

	Day Ahead Market	Hour Ahead Market	Quantity Weighted Price	Percent Purchased in Day Ahead
Regulation Up	$ 27.70	$ 26.15	$ 27.39	75%
Regulation Down	$ 21.64	$ 23.29	$ 22.05	80%
Spin	$ 10.52	$ 20.89	$ 12.54	81%
Non-Spin	$ 4.29	$ 17.53	$ 6.51	83%
Replacement	$ 23.73	$ 14.60	$ 21.90	80%

- The ISO's Ancillary Service markets were split zonally during many hours in October due to south-to-north congestion on Path 15. As a result, prices in zone NP15 were higher than in SP15. The following table compares weighted average A/S prices in the Day-Ahead market during peak and off-peak periods, along with the percentage of hours during which ancillary service were procured zonally in the Day-Ahead market.

	NP15		SP15		Percent of Hours with
	Peak	Off Peak	Peak	Off Peak	Zonal Procurement
Regulation Up	$ 46.36	$ 52.35	$ 14.24	$ 13.42	69%
Regulation Down	$ 23.20	$ 39.94	$ 16.50	$ 30.41	3%
Spin	$ 14.00	$ 4.46	$ 12.84	$ 3.46	30%
Non-Spin	$ 6.64	$ .02	$ 5.59	$ .02	18%
Replacement	$ 42.27	---	$ 12.38	--	19%

- The new $750 price cap taking effect in October was hit only one time during the month, with this occurring in the Hour-Ahead market for Regulation Up. However, A/S prices exceeded the previous $250 cap on numerous occasions in both the Day Ahead and Hour Ahead markets, as summarized in the table below:

Hours With MCP Greater than $250

	Day Ahead Market	Hour Ahead Market
Regulation Down	1	5
Regulation Up	11	9
Spin	1	7
Non-Spin	3	8
Replacement	5	3

Ancillary Service Costs

- Despite relatively high A/S prices resulting from zonal procurement during many hours and numerous prices in excess of $250, overall A/S prices remained below 5% of total energy costs.

Month	Avg. Daily A/S Cost* (Millions)	Avg A/S Cost per MWh of System Load ($/MWh)	A/S % of Energy Costs**
August	$ 1.289	$2.59	5.3%
September	$ 1.017	$1.85	4.3%
October	**$ 1.467**	**$2.28**	**4.6%**

* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)
** Energy cost = actual hourly loads multiplied by the PX Day-ahead Unconstrained MCP.

Cost Savings From A/S Re-Design Changes

The following table summarizes estimated savings from two key components of the A/S Redesign measures: the Rational Buyer protocols, and separate pricing for Upward and Downward Regulation. As shown below, these two measures have resulted in estimated savings of about $26 million since being implemented on August 17, representing savings of about 26% of total A/S costs during this time period. Our expectation is that our ability to calculate savings from Rational Buyer will diminish over time as more rational bidding behavior is exhibited in the market. This does not, however, mean savings have vanished but rather that they will be imbedded in bids. The savings from separate pricing of regulation should continue since the ISO was paying a single price for upward and downward regulation due to initial software constraints. These savings will, however, drop as the ISO procures less regulation service.

	Rational Buyer		Separate Pricing of Reg Up/Down	
	Savings	Pct. of Total A/S Costs	Savings	Pct. of Total A/S Costs
August *	$5,837,000	21%	$4,387,000	16%
September	$2,100,000	7%	$6,142,000	20%
October	$1,200,000	3%	$6,462,000	14%
Total	$9,137,000	9%	$16,991,000	17%

* Savings after implementation on August 17, 1999.

In the Congestion Management Markets

- Path 15 experienced significant congestion during peak hours and off-peak hours (south to north) with congestion occurring in 75% of peak hours and 68% of off-peak hours. Day Ahead prices on Path 15 ranged from $.01/MW to $698/MW and averaged $21.56/MW, down from September's average of $113/MW.

- Day-Ahead congestion patterns on the northwest paths moderated in October compared to September. On COI, Day-Ahead congestion occurred for the import direction during 23% of peak hours and 11% of off-peak hours, down from congestion rates of 53% and 34%, respectively, in September. Average congestion charges on COI fell from $71/MW in September to an average of $37/MW in October. On NOB, Day-Ahead congestion occurred in 13% of off-peak hours, predominantly in the export direction, similar to levels experienced in September.

- October congestion patterns on the southwest paths were also lower than September levels. Palo Verde experienced congestion for 7% of all hours in October, compared to the September rate of 18%, while

Eldorado had an October congestion rate of 10% compared to a September value of 28%. Congestion charges were generally lower in October as well with the average for Eldorado falling from $37/MW in September to $13/MW in October.

Day Ahead Market – Congestion Summary for October 1999

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**Total**	**Peak**	**Off peak**	**Total**
Path 15	76%	69%	74%	$26.38	$11.06	$21.56
COI	23%	11%	19%	$43.98	$9.01	$37.88
Palo Verde	1%	18%	7%	$1.23	$11.61	$10.57
NOB	0%	13%	4%	$306.87	$163.51	$206.27
Eldorado	1%	27%	10%	$12.31	$12.61	$12.59
Sylmar-AC	2%	0%	2%	$34.59		$34.59

Issues Under Investigation

1. ***Intra-zonal Congestion Management Reform.*** The existing Intra-zonal Congestion Management (AZCM) procedure provides gaming opportunities that have not been adequately addressed in the past. It is also based on the unrealistic assumption that a competitive market exists to mitigate intra-zonal congestion. Except for Path 26 (which will become an inter-zonal interface as of February 1, 2000), the ISO has thus far not encountered workably competitive markets for AZCM when confronted with congested intra-zonal interfaces. A gaming potential exists in the AZCM decremental bid market regardless of the existence of workable competition.

   Lack of workable competition in the real-time AZCM market 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 in the rejection of the Board's New Generation Interconnection Policy (NGIP) by the FERC, and its resolution was the main line of defense the ISO used in its request for rehearing on NGIP. Addressing both the lack of workable competition in AZCM, and the flaw in the design of the AZCM decremental bid market (even under competitive market conditions) are essential prerequisites for Portfolio Bidding, a project on the Board's approved list of the Market Redesign 2000 projects. Portfolio Bidding may require resolution of AZCM in the forward market with an entirely new approach.

   As directed by the Board at the October 28 Board meeting, a stakeholder process has been organized to clarify how Out-Of-Market protocols would be used in the context of non-competitive real-time AZCM.

2. ***Support Market Redesign 2000 (MR 2000).*** DMA continues its active participation in the MR 2000 stakeholder process, with particular emphasis on market power, gaming, and market efficiency issues. The main MR 2000 projects under continued DMA review are:

   - Mitigation of Large Uninstructed Deviations
   - Intra-zonal Congestion Management Reform
   - Portfolio Bidding and Inter-SC Trades Adjustment Bids
   - A/S CONG Integration
   - Non-firm Transmission

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.

3. ***Studies Ordered by FERC.*** The DMA has the lead on evaluating the efficiency of ancillary services procurement based on capacity bids only (single-part bid) or capacity and energy bids (referred to as the two-part bid). This study is one of three studies ordered by FERC in the October 1997 Order. The other two, led by Market Operations, involve analysis of the Congestion Zone Criteria (the 5% intra-zonal congestion cost criterion for creation of a new congestion zone), and Transmission Loss Allocation. DMA is reviewing all three studies for consistency. The studies are due at the end of November, and will be presented to the Board under separate cover for discussion at the November Board meeting.

4. ***FTR Market Design and Monitoring.*** DMA is reviewing various alternatives to facilitate entry of future converted ETC capacity into the FTR market, compatible with the FTR market design. DMA is also implementing components of its FTR Market Monitoring System (MMS) which will facilitate tracking of FTR concentration by affiliate groups, as well as by Owner and SC, along with other FTR market indices.

5. ***Analysis of Market Power in the San Diego Basin.*** In its September 29 order accepting DMA's Annual Report, FERC directed the DMA to submit, by December 31, 1999, a report addressing an evaluation of the market in the San Diego Basin. FERC based this directive on the Commission's October 30, 1997 Order, in which the Commission accepted SDG&E's market power mitigation proposal as adequate to mitigate market power in the transition period, but directed both the ISO and the PX "to monitor for market power in the San Diego Basin and to present information in their annual reports that could assist in the evaluation of this issue." (81 FERC P 61,122 at 61,546)

6. ***Investigation of Potential Implications of Negative Adjustment Bids.*** Stakeholders have expressed a desire to change the current floor for Adjustment Bids ($0) to a level similar to that of Imbalance Energy bids (-750 $/MWh). This would provide better consistency among the forward and real-time markets since the unused Adjustment Bids in the forward market are used in the real-time market along with Imbalance Energy bids for real-time Intra-zonal Congestion Management (AZCM). However, some Stakeholders have expressed concern that the Tariff treats the unused Adjustment Bids (sometimes submitted 30 hours before the operating hour) as binding bids through the operating hour; they would like to have Adjustment Bids expire after the forward market in which they were submitted. In that case, the issue of inconsistency of the Adjustment Bids and Imbalance Energy Bids would not prevail. DMA is investigating possible implications of negative Adjustment Bids with special attention to the existing gaming potential in the Intra-zonal Congestion Management (AZCM) decremental bid market, the FTR markets, and consistency with forward energy markets.