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: December 9, 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 November. Our attached Weekly Market Reports provide more detailed information.

NOVEMBER HIGHLIGHTS

The market events of November 1999 were highlighted by low ancillary service costs and prices moderating throughout the ISO's markets compared to the prior month. Ancillary service costs as a percentage of total energy costs amounted to only 3% in November, the lowest percentage since start-up. In the ISO real-time energy market, prices continued their downward trend of recent months. In addition, there was only one hour-ahead market which hit the $750 price cap. The ISO real-time energy prices closely tracked PX energy prices.

KEY MARKET CONDITIONS FOR NOVEMBER 1999

<u>In the California Energy Markets</u>

- November 1999 system energy loads totaled 18,104 GWh - a 10% decrease from October 1999, and a 7% increase over November 1998 loads. Daily peak loads averaged 30,507 MW, roughly 7.5% higher than November 1998 peak loads. The peak load for the month occurred at 6:00 PM on November 16, reaching 32,599 MW.

- Prices in both the ISO's Real-Time energy market and PX Day-Ahead market continued to be marked by 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 about 50% higher in NP15 than SP15, while constrained PX energy prices were about 28% higher in NP15 than SP15. The PX Day-Ahead market was split zonally due to congestion on Path 15 during 63% of the hours in the month, while the ISO's Real-Time market was split zonally during about 35% of hours in November.

Energy Price Summary for November 1999

	System Average	NP15	SP15	Pct. Hours of Zonal Pricing
Real-time Price				
Peak	$ 46.74	$ 54.42	$ 39.05	32%
Off-Peak	$ 26.61	$ 35.36	$ 17.86	40%
Total	$ 40.03	$ 48.07	$ 31.99	35%
PX Constrained				
Peak	$ 38.71	$ 42.70	$ 34.71	55%
Off-Peak	$ 23.89	$ 28.28	$ 19.49	80%
Total	$ 33.77	$ 37.90	$ 29.64	63%

- 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 $31.99/MWh compared to an average constrained PX price of $29.64/MWh. In NP15, real-time prices averaged $48.07/MWh compared to an average constrained price in the PX of $37.90/MWh.

- Prices in the both the PX Day-Ahead and ISO Real-Time energy markets were substantially higher in November compared to the same month last year. Real-time prices exceeded average prices during November of last year by about 46%, while PX unconstrained prices rose by about 43% compared to November 1998.

- The increase in PX and real-time energy prices in November 1999 compared to November 1998 can be attributed to a number of factors, including: (1) higher loads; (2) less energy from hydro, nuclear, and other regulatory must-take/must-run sources in California; (3) increased reliance on higher-cost thermal units; and (4) the need to procure energy zonally during many hours due to congestion on Path 15.

- As shown in the table below, the average total final hour-ahead schedules in November 1999 exceeded those in November 1998 by about 8%. At the same time, total generation scheduled from hydro and nuclear sources decreased by a total of about 1,750 MW, or about 7% of total average hour-ahead schedules. These two trends required increases of about 40% in generation scheduled from thermal units compared to November 1998.

Generation Source – November 1998 and 1999

	Average Hourly MW*		Difference	
Generation Source	**Nov-98**	**Nov-99**	**MW**	**Percent**
Hydro	2, 876	1,406	-1,470	-51%
Nuclear/Coal	5,675	5,387	-288	-5%
Other Reg. Must-Take/Must Run	5,064	4,700	-364	-7%
Other Thermal	5,103	7,189	2,086	41%
Imports	6,607	8,438	1,831	28%
Exports	-1,579	-1,389	189	-2%
Totals	23,746	25,730	1,984	8%

- There were three instances of negative real-time prices in SP15, each occurring with a zonal split of the BEEP stack. The first two instances occurred at HE 7 on November 14 and HE 1 on November 15 with negative prices of -$223/MWh and -$250/MWh, respectively. In both cases, system conditions required the ISO to exhaust all available decremental energy bids from the BEEP stack. The third incident occurred at HE 1 on November 20 with a price of -$428/MWh. This SP15 price was set by a large negative incremental bid. This can happen when market participants submit negative incremental bids to ensure being selected in the Real-Time Market with the expectation that a higher-priced bid will set the market price. In this instance, the negative price was accepted when additional incremental generation was not required.

- Although prices in the Real-Time Market or PX never hit the $750 price cap, prices exceeded the $250/MWh level during 6 hours in the Real-Time Market, while constrained PX Day-ahead prices did not exceed $125/MWh during any hour in November. The maximum real-time price of $492/MWh occurred at HE 11 on November 1 for zone NP15.

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 72% to 89% of A/S being procured in the Day-Ahead market. The following table summarizes weighted average prices in November 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 Down	$ 11.69	$ 17.99	$13.24	72%
Regulation Up	$ 22.68	$ 29.08	$ 24.49	76%
Spin	$ 3.70	$ 3.38	$ 3.65	86%
Non-Spin	$ 1.79	$ 1.56	$ 1.77	89%
Replacement	$ 1.65	$ .57	$ 1.47	83%

- The ISO's Ancillary Service markets experienced substantially less hours of zonal procurement in November relative to October due to congestion on Path 15 south to north. Prices in zone NP15 were higher than in SP15 though the differences narrowed compared to October. 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 services were procured zonally in the Day-Ahead market.

	NP15		SP15		Percent of Hours with Zonal Procurement
	Peak	Off Peak	Peak	Off Peak	
Regulation Up	$ 11.08	$ 12.49	$ 10.44	$15.19	8.6%
Regulation Down	$ 23.07	$ 36.67	$ 16.78	$ 31.14	0.0%
Spin	$ 4.24	$ 1.40	$ 5.44	$ 1.54	0.3%
Non-Spin	$ 2.28	$ .06	$ 2.69	$ .19	0.3%
Replacement	$ 2.38	---	$ 1.51	--	4.4%

- The $750 price cap was hit only one time during the month, occurring in the Hour-Ahead market for Regulation Down. However, other than this $750/MW price, A/S prices did not exceed $125/MW in either the Day-ahead and Hour-ahead markets.

Ancillary Service Costs

- A/S costs in November were considerably lower than in previous months, due, in part, to substantially less zonal procurement. Overall A/S costs reached an all-time monthly low of $21,603,659 or 3.1% 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****
September	$ 1.017	$1.85	4.3%
October	$ 1.467	$2.28	4.6%
November	**$.720**	**$1.19**	**3.1%**

* 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 $31.2 million since their implementation on August 17, representing savings of about 24% of total A/S costs during this time period. Our expectation is that savings from Rational Buyer will diminish over time as more rational bidding behavior is exhibited in the market. 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 also 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 *	$6,000,000	20%	$ 3,213,000	11%
September	$1,350,000	4%	$ 5,460,000	18%
October	$1,790,000	4%	$ 6,176,000	14%
November	$600,000	3%	$ 6,612,000	31%
Total	$9,740,000	8%	$ 21,461,000	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 53% of peak hours and 80% of off-peak hours. Day-Ahead charges on Path 15 ranged from $.01/MW to $68.21/MW and averaged $13.07/MW, down from October's average of $21.56/MW.

- Day-Ahead congestion patterns on the northwest paths increased in November compared to October. On COI, Day-Ahead congestion occurred for the import direction during 64% of peak hours and 38% of off-peak hours, up from the October congestion rates of 23% and 11%, respectively. Average congestion charges on COI fell from $37/MW in

October to an average of $5.74/MW in November. On NOB, the Day-Ahead congestion rate for all hours was 2%, which compares to the 4% congestion rate congestion rate experienced in October.

- November congestion patterns on the southwest paths were mixed compared to October levels. Palo Verde experienced increased congestion, to 17% of all hours in November compared to the October rate of 7%, while Eldorado's congestion rate in November decreased to 4% compared to the October rate of 10%. November congestion prices remained relatively unchanged for Palo Verde and Eldorado when compared to the previous month.

Day-ahead Market – Congestion Summary for November 1999

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**Total**	**Peak**	**Off peak**	**Total**
Path 15	64%	38%	55%	$14.64	$10.94	$13.07
COI	53%	80%	62%	$ 6.21	$ 4.13	$ 5.74
Palo Verde	14%	23%	17%	$13.15	$10.73	$12.05
NOB	3%	0%	2%	$ .03	$ .03	$ .03
Eldorado	5%	3%	4%	$17.53	$ 5.56	$14.91
Summit	16%	9%	13%	$ 6.75	$ 3.49	$ 6.05
Mead	2%	0%	12%	$23.41	$18.63	$22.97

ISSUES UNDER INVESTIGATION

1. **Intra-zonal Congestion Management Reform (AZCM).** The ISO has taken a two-step approach to correct the existing flaws in the AZCM market and mitigate AZCM market power resulting from lack of workable competition:

   a) The immediate target is to correct problems in the real-time AZCM. On November 10, 1999, the ISO filed with FERC Amendment 23 on Out-of-Market (OOM) calls and payments. If approved, this will allow the ISO to pay a combination of cost-based and market-based compensation, instead of bid prices, to mitigate AZCM in real-time where there is no competitive AZCM market. Different OOM payments would apply to the incremental and decremental dispatch for AZCM. Because of the continuing misuse of the flaw in the decremental AZCM, the DMA suggests a further correction to the Tariff for decremental AZCM dispatch (to block the perverse "dec" game) when no competitive market exists. This solution will be based on settling the decremental bids used out-of-sequence for AZCM at the *ex-post* price rather than as-bid.

   b) Next, the ISO plans to target AZCM in the forward market, and file Tariff language with FERC before summer of 2000. The mitigation measures would depend on whether or not portfolio bidding is implemented. The general direction contemplated is to price the decremental dispatch for AZCM at the corresponding zonal energy price (PX price or another energy price index). For AZCM incremental dispatch, a number of alternatives are under consideration, depending on whether or not a competitive market exists, and whether or not portfolio bidding is implemented. One possible approach considered in conjunction with portfolio bidding is to conduct AZCM in the Day-Ahead market for information only, and leave it to the market participants to mitigate AZCM through bilateral arrangements and Inter-SC trades and revise their schedules in the Hour-Ahead market accordingly.

2. **Support Market Redesign 2000 (MR 2000).** DMA continues to participate in the MR 2000 stakeholder process, with particular emphasis on evaluating design changes for their impact on market power, gaming, and market efficiency. The main MR 2000 projects under continued DMA review are:

- Mitigation of Large Uninstructed Deviations
- Intra-zonal Congestion Management Reform
- Inter-SC Trades Adjustment Bids
- Portfolio Bidding
- 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. **FTR Market Design and Monitoring.** The 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 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, along with other FTR market indices.

4. **GMC Unbundling Project Support.** Upon the request of the GMC Unbundling project team, DMA reviewed various alternatives developed for the GMC "buckets" and "billing determinants". DMA pointed out areas where some of the alternatives could lead to market inefficiencies (*e.g.* changes in scheduling behavior resulting from GMC allocation rules that would penalize those who participate in the organized energy and Ancillary Services markets), and suggested other alternatives where relevant (*e.g.,* allocation of a congestion management "bucket" based on net zonal schedules). DMA continues its collaboration with the GMC Unbundling project team as needed.

5. **Analysis of Market Power in the San Diego Basin.** DMA has completed a preliminary report to FERC on the subject of Market Power in the San Diego Basin. This report is included in a separate tab. In its September 29 letter order accepting DMA's Annual Report, FERC directed the ISO to submit, by December 31, 1999, a report evaluating the market in the San Diego Basin. FERC based this directive on the Commission's Oct. 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 have the current floor for Adjustment Bids ($0) changed to a level similar to that of the Imbalance Energy bids (-$750/MWh). This would provide better consistency among the forward and real-time markets since unused Adjustment Bids in the forward market are used in the real-time market along with the Imbalance Energy bids for real-time Intra-zonal Congestion Management (AZCM). Some have mentioned that negative Adjustment Bids are sometimes needed to reflect the reality of their contractual commitments. 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, the Inter-zonal Congestion management markets, and consistency with forward energy markets.