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: January 13, 2000

Re: Market Analysis Report

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

This report summarizes key market conditions, developments, and trends for the month of December. **Attachment A** is a year-end summary of market performance in 1999 compared to the ISO's first year of operation. Weekly market reports for December are also attached to provide more detailed information on market performance in December.

DECEMBER HIGHLIGHTS

The market events of December 1999 were highlighted by very low ancillary service costs and energy prices, a considerable moderation from patterns of recent months. Significant lessening of congestion on Path 15 allowed both PX and ISO real-time energy prices to converge for zones SP15 and NP15. Average PX energy prices were approximately the same as December 1998, while the ISO real-time energy market prices were about 16% above December 1998 levels. The highest energy prices experienced were $220/MWh in the ISO real-time market and $55.51/MWh in the PX energy market. Ancillary service costs as a percentage of total energy costs amounted to only 1.8% in December, the lowest percentage since start-up. Apart from a $190/MW price in the day-ahead Regulation Up market, ancillary service prices averaged $12.50/MW for Regulation Down to $0.58/MW for Replacement Reserves.

KEY MARKET CONDITIONS FOR DECEMBER 1999

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

- December 1999 system energy loads totaled 19,284 GWh, a 6.5% increase over November 1999 and a 5% increase over December 1998 loads. Daily peak loads averaged 31,734 MW, roughly 5% higher than December 1998 peak loads. The peak load for the month occurred at HE 18 on December 13, reaching 34,319 MW.

- Prices in both the ISO's real-time energy market and PX day-ahead market moderated considerably compared to recent months. Constrained PX prices were about 17% lower in December compared to November, while ISO real-time prices were about 28% less than November levels. Significant decreases in Path 15 congestion narrowed the recent differences between constrained prices in zones NP15 and SP15. As shown in the table below, average real-time energy prices were only about 2% higher in NP15 than SP15, while constrained PX energy prices were only 5% higher in NP15 than SP15. The PX day-ahead market was split zonally due to congestion on Path 15 during 42% of the hours in the month, while the ISO's real-time market was split zonally for only 2% of the hours in December.

Energy Price Summary for December 1999

	System Average	NP15	SP15	Pct. Hours of Zonal Pricing
Real Time Price				
Peak	$ 34.46	$ 34.81	$ 34.11	3.0%
Off-Peak	$ 27.97	$ 28.12	$ 27.81	.1%
Total	$ 32.30	$ 32.58	$ 32.01	2.4%
PX Constrained				
Peak	$ 31.53	$ 31.90	$ 31.16	29%
Off-Peak	$ 23.79	$ 25.31	$ 22.27	69%
Total	$ 28.95	$ 29.70	$ 28.19	42%

- Prices in the ISO's real-time energy markets were about 12% higher than the PX day-ahead energy market prices for December. As shown in the preceding table, ISO real-time prices in SP15 averaged $32.01/MWh compared to an average constrained PX price of $28.19/MWh. In NP15, ISO real-time prices averaged $32.58/MWh compared to an average constrained price in the PX of $29.70/MWh. The higher prices in the ISO real-time market may be due, in part, to the systematic demand for incremental generation by the ISO for the month of December. In December, the ISO called upon net incremental generation during 85% of the hours at an average of 806 MW incremented.

- PX unconstrained energy prices for December 1999 were about 1.3% higher compared to December 1998 while the average ISO real-time price was about 16% higher than the same month last year.

- Energy prices in both the real-time market and PX markets were very moderate compared to recent months. The real-time market experienced only four hours where prices exceeded $70/MWh, with a maximum price of $220/MWh occurring at HE 21 on December 2. Constrained PX energy prices exceeded $50/MWh for only three hours during the month. The maximum unconstrained PX energy price of $55.51/MWh occurred at HE 18 on December 27.

<u>In the Ancillary Service Markets</u>

Ancillary Service Prices

- The ISO continued to procure the bulk of A/S in the day-ahead market, with an average of about 83% to 90% of A/S being procured in the day-ahead market. The following table summarized weighted average prices in December 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	$ 7.50	$ 7.18	$ 7.45	86%
Regulation Down	$ 12.67	$ 11.53	$ 12.51	86%
Spin	$ 1.54	$ 1.40	$ 1.52	87%
Non-Spin	$ .54	$ .47	$ .54	90%
Replacement	$ .68	$ .09	$ .58	83%

- The ISO's Ancillary Service markets experienced substantially less hours of zonal procurement (due to less congestion on Path 15) in December relative to preceding months. As a result, differences in the average prices between zone NP15 and SP15 narrowed considerably compared to recent months. 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.

	NP15 Peak	Off Peak	SP15 Peak	Off Peak	Percent of Hours with Zonal Procurement
Regulation Up	$ 6.60	$ 6.80	$ 8.78	$ 10.38	9.4%
Regulation Down	$ 10.82	$ 17.67	$ 10.71	$ 16.59	3.2%
Spin	$ 1.41	$ .67	$ 4.18	$ 1.65	7.8%
Non-Spin	$ .55	$ .12	$ .88	$ .17	7.3%
Replacement	$ .61	---	$ .78	--	4.3%

- There were no hours where the $750 price cap was reached in any of the A/S markets during the month. The maximum price experienced in any of the A/S markets was $190/MW in the day-ahead spinning reserve market for zone SP15. Beyond this price, A/S prices did not exceed $80/MW in either the day-ahead or hour-ahead markets.

Ancillary Service Costs

- A/S costs in December 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 $10,570,000 or 1.8% 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**
October	$ 1.467	$2.28	4.6%
November	$ .720	$1.19	3.1%
December	**$.341**	**$.55**	**1.8%**

* 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 Redesign Changes

The following table summarizes estimated savings from two key 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 $34.8 million since their implementation on August 17, representing savings of about 26% 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. However, as shown in the table below, significant direct savings continue to be realized from the application of the Rational Buyer protocols to bids submitted to the ISO by market participants. 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. However, 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%
December	$577,000	5%	$3,056,000	29%
Total	$10,317,000	8%	$ 24,518,000	18%

* Savings after implementation on August 17, 1999.

Inter-zonal Congestion Management Markets

- Path 15 experienced lower congestion (S-N) compared to November with peak hours and off-peak hours congestion rates (south to north) of 28% for peak hours and 69% for off-peak hours which compares to November's congestion rates of 53% and 80%, respectively. Day-ahead congestion charges on Path 15 ranged from $.01/MW to $20.22/MW and averaged $3.60/MW, down from November's average of $13.07/MW.

- Day-ahead congestion on the northwest paths was generally lower in December compared to November. On COI, day-ahead congestion occurred for the import direction during 56% of peak hours and 40% of off-peak hours, compared to the November congestion rates of 64% and 38%, respectively. Average congestion charges on COI fell from $5.74/MW in November to an average of $2.54/MW in December. On NOB, the day-ahead congestion rate for all hours was 4%, which compares to the 2% congestion rate congestion rate experienced in November.

- December congestion on the southwest paths increased compared to November levels. Palo Verde experienced an increased congestion rate of 31% for all hours in December compared to the November rate of 17% while Eldorado's congestion rate in December increased to 13% compared to the November rate of 4%. Average congestion prices fell for both Palo Verde and Eldorado, averaging $5.66/MW and $6.89/M, respectively, in December compared to November's average prices of $12.05/MW and $14.91/MW, respectively.

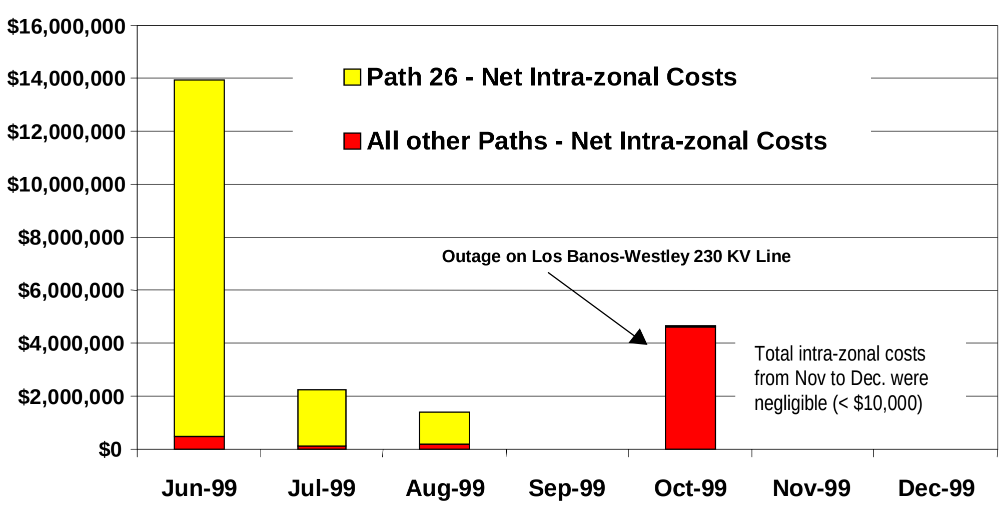
Day-Ahead Market – Congestion Summary for December 1999

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	Total	Peak	Off peak	Total
Path 15 (S-N)	29%	69%	42%	$2.60	$4.43	$3.60
COI (Import)	56%	40%	51%	$2.87	$1.62	$2.54
Palo Verde (Import)	33%	27%	31%	$5.06	$7.12	$5.66
NOB (Import)	6%	0%	4%	$.03	$.00	$.03
Eldorado (Import)	15%	9%	13%	$7.60	$4.67	$6.89
IID-SCE (Import)	0%	1%	1%	$30.00	$30.00	$30.00

Within Zone or Intra-zonal Congestion Costs

The following chart shows the net monthly cost of intra-zonal congestion from June to December 1999. These costs are grouped into two categories: 1) intra-zonal costs for Path 26; and 2) intra-zonal costs for all other paths. Net monthly costs are calculated based on the total or "gross" cost of energy dispatched for intra-zonal congestion minus the value of this energy in the real-time market.

Within Zone or Intra-zonal Congestion Costs (June-December 1999)



Over the seven-month period from June to December, the total net cost of intra-zonal congestion was $22 million. Net intra-zonal congestion on Path 26 accounted for about $17 million, or 75% of intra-zonal congestion costs. The sharp drop in intra-zonal congestion costs on Path 26 after June was due to the emergency filing and implementation of Amendment 18, which eliminated the gaming and exercise of market power responsible for the high Path 26 intra-zonal congestion costs in June. Amendment 18 allowed the ISO to use Adjustment Bids and Imbalance Energy Bids to alleviate intra-zonal congestion, and lifted the restriction to use the bids within the congestion zone before going outside the zone.

Intra-zonal congestion costs on other paths accounted for about $5.4 million during the last seven months of 1999. The high costs of intra-zonal congestion in October can be attributed almost entirely to one incident where a market participant engaged in anomalous behavior when line outages occurred on the Tesla-Los Banos and Tracy-Los Banos 500 KV lines on October 28. In a six-hour period on this day, the net cost of intra-zonal congestion was approximately $4.6 million.

It should be noted that this data does not include real-time RMR dispatches for intrazonal congestion. Intrazonal congestion can be due to a number of factors, including transmission maintenance, line outages, and scheduled or forced outages of other facilities, all of which are related to local reliability, versus market behavior, which is independent of local reliability requirements. Historical data on real-time RMR dispatches does not allow us to differentiate between RMR dispatched to ensure local reliability and cases in which RMR was dispatched solely to mitigate intra-zonal congestion unrelated to local reliability needs. In reviewing real-time RMR dispatch for intrazonal congestion, we found these costs to be minimal because often RMR variable costs were lower than the prevailing ex-post price at the time of intrazonal congestion.

ISSUES UNDER INVESTIGATION

1. **Analysis and Design of 10-minute Dispatch and Settlement.** The DMA has actively participated in the design and analysis of 10-minute Dispatch and Settlement along with the other ISO departments and stakeholders. The DMA provided advice on the major design elements of 10-minute Dispatch and Settlement implementation to ensure market efficiency, avoid differential treatment of suppliers within and outside the ISO Control Area, and discourage gaming.

2. **Analysis of Market Power in the San Diego Basin.** In its September 29 letter order accepting the DMA's Annual Report, FERC directed the ISO 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."

   The DMA completed and filed this report to FERC on December 30,1999. This report has been posted on the ISO website. The main finding of the report is that despite divestiture of SDG&E's generation assets to two owners, there remains a significant potential for generation owners in the San Diego basin to exercise market power. Any attempt to exercise this market power is, however, presently mitigated by the RMR contracts. Any major market design changes (such as modification of RMR contracts or creation of a new zone) should be preceded by more detailed analysis of how market power could be affected as a result, and what mitigation measures would be needed. The DMA also recommended that market power considerations be incorporated into analysis of different options for meeting new load growth in the San Diego Basin, including new transmission capacity, new generation, re-powering of existing generating units, and demand-side options.

3. **Intra-zonal Congestion Management Reform (AZCM).** The DMA investigated the existing flaws in the ISO's AZCM market design, and supported the ISO's effort in conjunction with Amendment 23, involving the use of out-of-market calls for AZCM on the non-competitive interfaces as a short-term solution. The FERC Order of January 7, 2000 rejected this element of the ISO's proposal and ordered an integrated redesign of the AZCM market. The DMA will be analyzing different options in response to FERC's direction.

4. **FTR Market Design and Monitoring.** The DMA continues its efforts to complete the FTR Market Monitoring System (MMS) which will track FTR scheduling, sales, and concentration by affiliate groups as well as by

Owner and SC, along with additional market indices that will assess the impact of FTRs on other ISO markets.

5. **Analysis of the Impact of Inter-zonal Congestion.** The DMA analyzed the economic impact of inter-zonal congestion on consumers in California. This was done at the request of the Transmission Access Charge project. The analysis will be expanded to quantify the impact of congestion on both load and generation.