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 20, 2000

Re: Market Analysis Report

This is a status report only. No Board action is required.

This report summarizes key market conditions, developments, and trends for November 2000.

NOVEMBER HIGHLIGHTS

- Energy costs rose sharply in November due to a combination of factors, including (1) soaring high natural gas prices, (2) a high level of planned and forced outages, (3) high emissions costs and annual emissions constraints on many thermal generating units, (4) low hydro generation within California and (5) a drop in available imports from the Northwest.

- Temperature conditions were comparable to 1999, with a cold spell in the third week of November driving loads up. The monthly peak reached 33,180 MW, up 1.8% from November 1999, while total energy increased by 3%. Average daily peaks reached 30,900 MW, up from 30,700 MW in October.

- The estimated total energy and A/S cost for November was $3.2 billion, or about $172/MWh of load served, compared to about $1.9 billion ($100 per MWh of load served) in October.

- The average constrained PX price for the month was $143, up 325% from $34/MW in November 1999 and up 58% from the $91/MWh average in October. Real time prices (SP15 & NP15) averaged $164/MWh, up 55% from the October value of $106/MWh and up 310% from November 1999.

- October prices (weighted by volume purchased) in the ancillary service markets increased sharply compared to October. Regulation up, regulation down, spinning reserve, and non-spinning reserve prices all increased from 25% to 100% compared with October. Replacement reserve prices increased by 435%.

- Ancillary service costs increased to $6.13 per MWh of load compared to the October value of $2.95/MWh and the November 1999 value of $1.19/MWh. Total A/S costs were about $114 million in November 2000, which is about 4% of total wholesale energy costs in November, compared to the October rate of 3%.

- Natural gas prices increased sharply in November, from approximately $5.50MMBTU at the beginning of the month to $18/MMBTU by the end of the month, averaging roughly $10.65/MMBTU.

- Import congestion rates increased from the Northwest in November compared to October, while import congestion on the on from the Southwest was varied compared with last month.

- Path 15 experienced significantly higher congestion in the South to North direction, which contributed to higher prices in the North for the month. Congestion on Path 15 was due primarily to a heavy demand for transmission the south-to-north direction, but was also exacerbated by a de-rates in available transmission capacity in the south-to-north direction on path 15 due to maintenance outages. Total congestion costs for November were about $72.4 million, a substantial increase over the October costs of about $28.7 million as well as the November 1999 cost of $10.7 million. Path 15 and Palo Verde incurred the largest congestion costs with a totals of about $30 million each.

KEY MARKET CONDITIONS FOR OCTOBER 2000

I. <u>California Wholesale Energy Markets</u>

- **Loads –** November loads declined somewhat from October due to moderate temperatures. Monthly system energy loads totaled 18,656 GWh, a 3% increase from November 1999. The peak load for the month reached 33,180 MW, a 1.8% increase over November 1999 levels, occurring at HE 18 on November 27. Daily peak loads averaged 30,921 MW, a 1.4% increase over November 1999.

- **Wholesale Energy Prices** – Energy prices in November increases sharply from those observed in October, due in part to significantly higher natural gas prices and unusually high outages across the system. System real time prices averaged $164.15/MWh while constrained PX prices averaged about $143.76MWh, roughly 310% and 324% increases, respectively, from November 1999 levels. Real time peak prices increased to $175.19/MW, up 52% from October and 275% from November 1999. Real time off-peak prices averaged $142.08/MW, up 63% from October and 434% from November 1999. Off-peak PX prices remained constant from last month.

  Under-scheduling in the day ahead market increased sharply in November compared to what was observed in October. On average, the ISO required nearly 2,000 MW of incremental generation during peak hours and nearly 750 MW during off-peak hours.

  Significant real time congestion persisted on Path 15 in the S-N direction, occurring during 74% of all hours. This resulted in a large difference between the average NP15 real time price of $199/MW and the average SP15 real time price of $128/MW.

  Natural gas prices increased sharply in November, from approximately $5.50MMBTU at the beginning of the month to $18/MMBTU by the end of the month, averaging roughly $10.65/MMBTU. This is a 260% increase compared with November 1999. High natural gas prices contributed to high PX and ISO energy prices in November.

- Both peak and off-peak period prices in the PX and ISO energy markets were slightly higher in NP15 than SP15. The ISO real time market experienced much higher prices in zone NP15 due in part to the significant real time congestion on Path 15 in the S-N direction and cool Fall temperatures in the North. Energy prices by zone and period are listed in Table I.

- The ISO real time market experienced 209 hours where the $250/MWh price cap was reached in either SP15 or NP15, a significant increase from 20 hours in October. There were 463 hours and 179 hours of prices at or above the $248/MWh level in NP15 and SP15, respectively. Forty three percent of the hours where prices were at or above $248/MW occurred during peak hours.

Table 1: Energy Price Summary for November 2000

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$175.19	$206.41	$143.97	$148.29	65%
Off-Peak	$142.08	$186.29	$97.86	$104.17	72%
Total	$164.15	$199.70	$128.60	$133.59	68%
PX Constrained					
Peak	$159.48	$181.40	$148.52	$148.52	57%
Off-Peak	$112.32	$153.12	$91.91	$91.91	96%
Total	$143.76	$171.97	$129.65	$129.65	70%

II. Ancillary Service Markets

Ancillary Service Prices

- The ancillary service prices hit the price cap 25 hours in the day ahead markets during November, with 19 of those hours in the Replacement Reserve market with a $100/MW price cap. The hour ahead market had a total of 77 price cap hits, with 50 hits occurring in the Replacement Reserve market.

- The ISO procured most of its A/S requirements in the day-ahead market, with between 81% and 85% of A/S MW quantities being procured in the day-ahead market (48% for Replacement Reserve). Table 2 below summarizes weighted average prices and quantity procurements for September 2000 in both the day-ahead and hour-ahead markets.

- Table 3 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 (day-ahead and hour-ahead combined).

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – October 2000

	Day-Ahead Market (all hours)	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$68.97	$67.14	$68.66	515	104	83%
Regulation Down	$ 54.62	$ 43.37	$ 52.49	494	115	81%
Spin	$ 35.02	$ 36.56	$ 35.26	693	129	84%
Non-Spin	$ 17.77	$ 40.11	$ 21.49	692	138	83%
Replacement	$ 48.72	$ 69.79	$ 59.63	305	327	48%

Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – November 2000

	NP15		SP15		Percent of Hours with
	Peak	Off Peak	Peak	Off Peak	Zonal Procurement
Regulation Up	$ 57.99	$ 90.86	$ 68.02	$ 79.77	11%
Regulation Down	$ 43.30	$ 64.12	$ 54.08	$ 94.50	5%
Spin	$ 33.16	$ 20.60	$ 52.29	$ 24.91	3%
Non-Spin	$ 16.82	$ 13.33	$ 27.71	$ 4.92	3%
Replacement	$ 47.96		$ 51.61		3%

Ancillary Service Costs

- A/S costs in November were $114 million compared to the October total of $57 million. November A/S costs were about 3.9% of total energy costs. Day ahead A/S prices in November were considerably higher than October, with regulation up prices increasing by 27%, regulation down increasing by 46%, spin/non-spin experiencing a 109% increase, and replacement increasing by 435% from October prices.

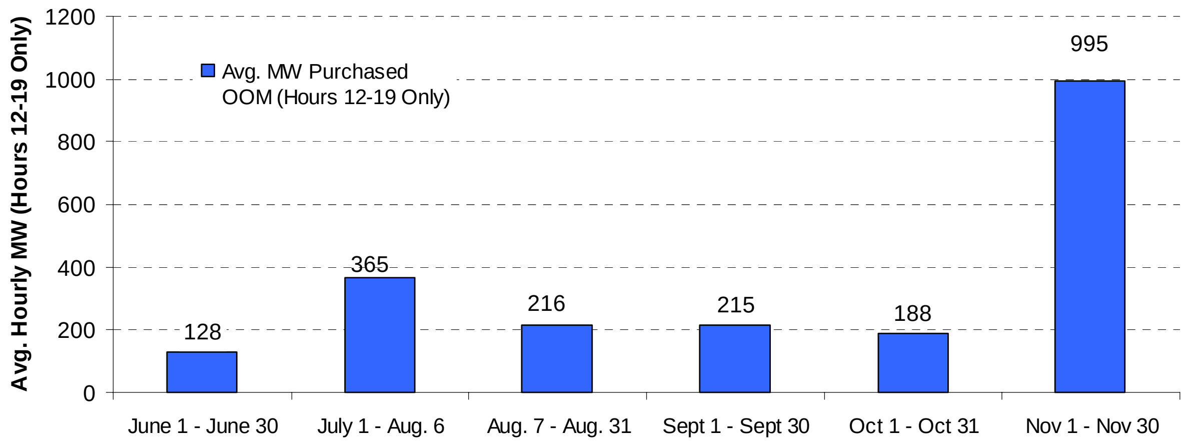
Month	Avg. Daily A/S Cost* (Millions)	Avg A/S Cost per MWh of System Load ($/MWh)	A/S % of Energy Costs
June	$14.533	$20.19	14.3%
July	$ 4.014	$ 5.71	5.1%
August	$ 9.097	$12.18	7.3%
September	$ 5.077	$ 7.38	6.0%
October	$ 1.845	$ 2.95	3.0%
November	**$ 3.815**	**$ 6.13**	**3.9%**

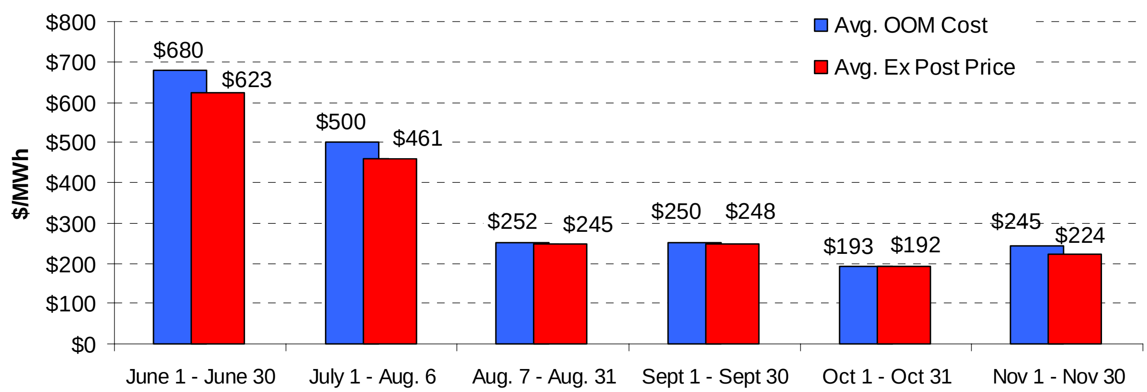
* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)

III. <u>Out of Market Calls</u>

After tapering off in October and the first two weeks of November, out-of-market purchases by the ISO due to general system shortages gradually increased the last two weeks of November. As gas prices rose, the ISO also faced the need to make some OOM purchases at prices above the $250 cap in late November. Although purchases above the $250 were minimal in November, OOM purchases above the $250 cap accelerated rapidly the first week of December. The rapid rise in volume of OOM purchases and the need to pay above the $250 level in December were key factors in the ISO's December 8 filing at FERC to implement the "soft cap" approach incorporated in FERC's November 1 order on an accelerate basis.

Average system condition out-of-market costs for November were $245/MWh, compared with the average ex-post price of $224/MWh at the time the calls were made. On average, 995 MW were purchased each peak hour in November (HE 12 - 19). There were a total of 390,591 MWh of energy purchased out-of-market in November at a total cost of $95.6 million. Some purchases were made at a price above the price cap, with the amount paid above the cap accounting for about 9.4% of total OOM costs in November. The charts on the following page summarize these trends in OOM purchases by the ISO in November and the first week of December.


1200
1000
800
600
400
200
0
Avg. Hourly MW (Hours 12-19 Only)
Avg. MW Purchased OOM (Hours 12-19 Only)
128
365
216
215
188
995
June 1 - June 30
July 1 - Aug. 6
Aug. 7 - Aug. 31
Sept 1 - Sept 30
Oct 1 - Oct 31
Nov 1 - Nov 30


$800
$700
$600
$500
$400
$300
$200
$100
$0
$/MWh
Avg. OOM Cost
Avg. Ex Post Price
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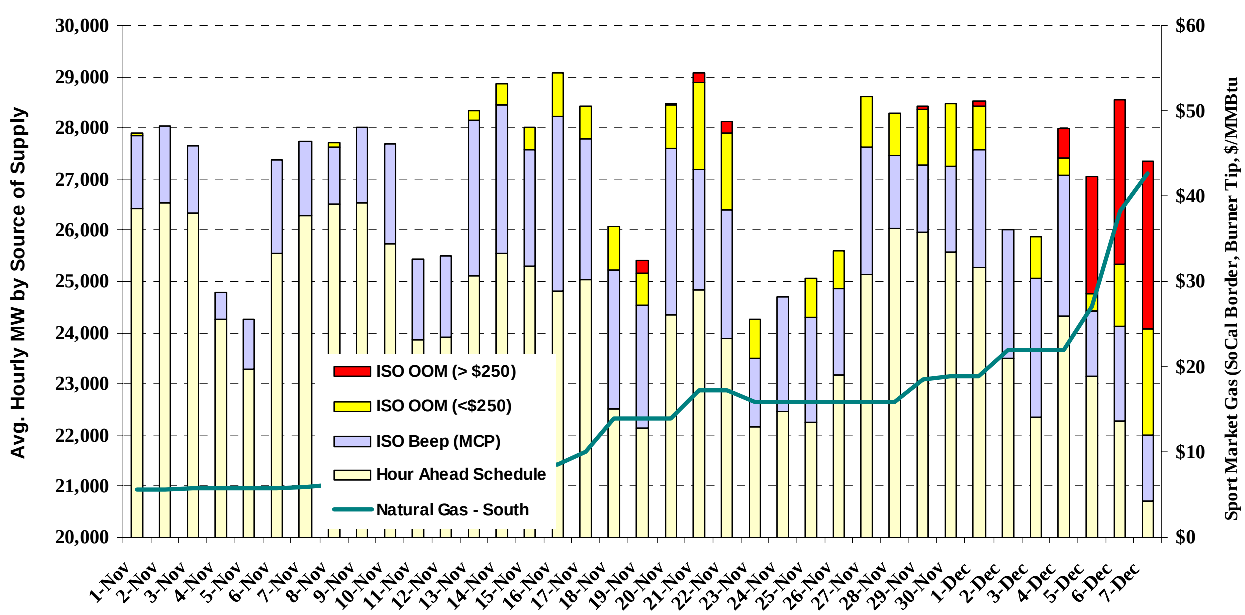
$623
$500
$461
$252
$245
$250
$248
$193
$192
$245
$224
June 1 - June 30
July 1 - Aug. 6
Aug. 7 - Aug. 31
Sept 1 - Sept 30
Oct 1 - Oct 31
Nov 1 - Nov 30


30,000
29,000
28,000
27,000
26,000
25,000
24,000
23,000
22,000
21,000
20,000
Avg. Hourly MW by Source of Supply
$60
$50
$40
$30
$20
$10
$0
Sport Market Gas (SoCal Border, Burner Tip, $/MMBtu
ISO OOM (> $250)
ISO OOM (<$250)
ISO Beep (MCP)
Hour Ahead Schedule
Natural Gas - South
1-Nov
2-Nov
3-Nov
4-Nov
5-Nov
6-Nov
7-Nov
8-Nov
9-Nov
10-Nov
11-Nov
12-Nov
13-Nov
14-Nov
15-Nov
16-Nov
17-Nov
18-Nov
19-Nov
20-Nov
21-Nov
22-Nov
23-Nov
24-Nov
25-Nov
26-Nov
27-Nov
28-Nov
29-Nov
30-Nov
1-Dec
2-Dec
3-Dec
4-Dec
5-Dec
6-Dec
7-Dec

IV. Inter-zonal Congestion Management Markets

Import congestion from the Northwest increased in November. Import congestion from the Southwest was varied compared with last month. Path 15 experienced significantly higher congestion in the South to North direction, which contributed to higher prices in the North for the month. The following table summarizes congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for November 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
Path 15 (S-N)	65%	93%	74%	$50.91	$66.17	$57.28
COI (Import)	15%	0%	10%	$1.43	$0	$1.43
Eldorado (Import)	9%	31%	17%	$26.67	$36.38	$32.79
NOB (Export)	20%	48%	29%	$67.33	$104.49	$87.50
Palo Verde (Import)	34%	33%	33%	$76.77	$41.59	$65.29

- Total Path 15 congestion increased to 74% in November, up from 68% in October. All of the congested hours were in the S-N direction. Of the congested hours, 42% were in the off-peak period. Day-ahead congestion charges on Path 15 averaged $57.28/MW, an increase from the October average of $23.65/MW.

- November import congestion on the southwest paths was mixed with October with Palo Verde and Eldorado experiencing congestion rates of 33% and 17%, compared with 17% and 29% in October. There were no other SW branch groups with any significant day ahead congestion. Average congestion prices for Palo Verde and Eldorado were $65.29/MW and $32.79/MW, respectively. Import congestion from the North increased compared to October with COI at 10%, up from 0%, and NOB at 29%, up from 22%. Average congestion charges on NOB increased from $22.40/MW to $87.50/MW.

- Total congestion costs for November were about $72.4 million, a substantial increase over the October costs of about $28.7 million as well as the November 1999 cost of $10.7 million. Path 15 and Palo Verde incurred the largest congestion costs with a totals of about $30 million each.

V. Performance of the FTR Market in November 2000

FTR Concentration

There were no secondary FTR market transactions and no new FTR SC assignments in November 2000. Thus there is no change in FTR ownership and control concentration to report.

FTR Scheduling

On most paths the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges. The relative volume of schedules with FTR priority attached for the period November 1-30, 2000 is indicated in the following table. Only paths on which FTRs were attached to schedules are listed.

Branch Group	COI EXP	NOB EXP	COI IMP	ELD IMP	IID-SCE	MEAD IMP	PV IMP	SilvPk IMP	Total
MW FTR Auctioned	33	442	422	694	600	366	1,650	10	9,553
Avg. MW FTR Scheduled	1	24	22	399	444	9	709	6	1,614
% FTR Scheduled	2%	5%	5%	58%	74%	3%	43%	60%	17%
Max MW FTR Scheduled	25	125	100	430	450	10	925	9	-
Max Single SC FTR Schedule	25	125	100	405	444	10	485	9	-

Secondary Market Activity

There were no secondary transactions during the month of November.

VI. Issues Under Review and Analysis

1. **Adjustment Bid Caps.** A couple of days after the implementation of the real-time soft cap in ISO's real-time market (Amendment 33 filed and approved on December 8, 2000), the PX constrained zonal prices started exhibiting logically unacceptable behavior. For example, with an unconstrained Market-Clearing Price (UMCP) of $1,000, the constrained prices were $250 in SP15 and $280 in NP15. This phenomenon could be explained as follows: The PX requires incremental (INC) Adjustment Bids (AB) to be greater than or equal to the UMCP, but the ISO does not accept INC ABs above $250. When the marginal PX DEC bid selected in SP15 is, for example, $250, since no PX INC bids can be submitted in NP15 without violating either the PX or the ISO rules, the congestion management system (CONG) uses the default usage charge, which is set at the higher of $30 or the difference (AB Cap minus the marginal DEC bid = $250-$250 =$0), i.e. a usage charge of $30. The PX zonal price calculator then sets the constrained price at $250 in SP15 (marginal DEC bid selected in CONG) and $30 higher ($280) in NP15. This is an illogical outcome since one would expect at least one of the constrained zonal prices to be at or above the unconstrained price

   The PX complained that this outcome was the result of softening the $250 cap in the real-time market and keeping the hard $250 cap in the Adjustment Bid market, and asked the AB Cap to be lifted according to forward market energy prices. The DMA had serious concerns about lifting AB Caps and indicate that the real problem was that the wrong commodity was being capped. The ISO DMA and the PX MMU worked together towards a solution that would cap the spread of the ABs (rather than the ABs themselves. An equivalent solution was worked out to have PX participants submit ABs in a ± $125 range around the PX UMCP. The PX would then subtract a bias ($875 in the above example with PX UMCP at $1,000) from all PX ABs before submitting them to the ISO. The ISO would thus always receive ABs in the $0 to $250 range. After congestion management the PX would compute its constrained zonal prices as usual and add back the bias.

2. **FERC Filings and Analysis of FERC Orders.** The DMA conducted an analysis of November 1, 2000 FERC Order, and contributed to the ISO response to this order as filed on November 22. The DMA also supported the emergency filing of December 8, 2000 (Amendment 33). Following the issuance of the final FERC Order on December 15, 2000, the DMA is investigation implementation and market power issues in the CMR context. The DMA will also be working with the FERC staff in developing longer-term market monitoring and mitigation to be developed by March 1, 2001.

3. **Modification of Market Monitoring and Analysis Systems in Response to Real Time Market Changes**. The ISO's December 8 filing allowing payment on an as bid basis for real time energy over the $250 price cap, combined with the high volume of out-of-market purchases prior to and after this filing, has created the need for DMA to design a variety of new processes for estimating and tracking total market costs and analyzing market trends. DMA is working closely with Market Operations staff and other parts of the ISO to develop and automate these new processes in order to facilitate DMA's ability to analyze, track and report on total market costs and market trends..

4. **Outage Reporting, Scheduling, and Availability Standards.** The DMA is collaborating with the Department Outage Co-ordination and other parts of the ISO in developing a white paper covering options for enhanced outage reporting, scheduling and availability standards and requirements.

5. **Status of External Investigations.** DMA continues to collaborate with investigations being performed by a variety of outside entities, including the FERC, CPUC, EOB and State Auditor.