California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: April 17, 2000

Re: Market Analysis Report - Summary of Key Market Conditions, Developments, and Trends for March 2000

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

MARCH HIGHLIGHTS

Prices in the PX and real time markets tracked closely during both peak and off-peak hours during March, but dropped 4% and 2%, respectively, from February 2000 levels. Average PX energy prices for March were 53% higher than a year ago while the ISO real-time energy market prices were about 43% above March 1999 levels. Loads were 4.3% greater than March 1999 loads. The higher energy prices may be attributable to a combination of higher loads, less generation from hydro and other sources of regulatory must-run generation, and higher natural gas prices.

Market participants significantly under-scheduled their loads in the hour-ahead market which placed a large amount of load into the ISO real time energy market. The average amount of under-scheduling for March for all hours was 1,539 MW compared to 470 MW in March 1999. The under-scheduling of loads occurred during 90% of all hours in March 2000, compared to a 74% rate in March 1999 and an 84% rate in February 2000.

Ancillary service prices were moderate throughout the month. Ancillary service costs as a percentage of total energy costs were 2.0% in March, similar to February, which is down substantially from a year ago. There were only two hours in the day-ahead market and only five hours in the hour-ahead market where prices exceeded $50/MW.

The major trend in the congestion markets was a significant shift of congestion away from the Northwest paths to the Southwest paths when compared to March 1999. Day-ahead congestion on both COI and NOB were almost non-existent for the month while Palo Verde experienced a congestion rate for 24% of all hours in March 2000. The day-ahead congestion for Path 26 was 16%, predominantly in the N-S direction, while the congestion rate on Path 15 was 11%, predominantly in the S-N direction. There were no transactions in the secondary FTR market in March. More FTR's have been assigned to scheduling coordinators and more are being submitted with transmission schedules.

KEY MARKET CONDITIONS FOR MARCH 2000

I. In the California Wholesale Energy Markets

- **Loads -** March 2000 system energy loads totaled 18,989 GWh (or 25,523 MWh average hourly which is 18,989 ÷31*24), a 4.3% increase over March 1999 loads. Daily peak loads averaged 30,373 MW, 4.7% higher than average daily March 1999 peak loads. The peak load for the month was 32,340 MW at hour ending at 1900 on March 7.

- **Wholesale Energy Prices** – The differences between peak and non-peak average energy prices widened in March compared to February 2000 (see Table 1 below). However, for constrained PX energy prices this difference (35%) is still in a more narrow range when compared to March 1999 (50%). Perhaps the most significant change in the energy markets is the higher PX constrained prices in zone SP15, reversing the pattern from previous months where NP15 constrained prices exceeded SP15 levels. The PX day-ahead market was split zonally due to congestion on Path 15/Path 26 during 27% of the hours resulting in constrained PX prices in SP15 being about 3% higher than NP15 prices.

  For the ISO real time energy market, average prices were nearly the same between the two zones, with NP15 average real-time energy prices about 1% higher than SP15. Only 3% of the hours in March experienced a zonal split in the real-time market. The lower zonal split rate in the real time market is due to differences in the usage of day-ahead capacity and real-time capacity on existing transmission contracts and success in clearing congestion prior to real-time.

Table 1: Energy Price Summary for March 2000

	System Average	NP15	SP15	Pct. Hours of Zonal Pricing
Real Time Price				
Peak	$ 31.93	$ 31.90	$ 31.96	1%
Off-Peak	$ 22.31	$ 22.65	$ 21.97	6%
Total	$ 28.72	$ 28.81	$ 28.63	3%
PX Constrained				
Peak	$ 31.10	$ 30.65	$ 32.21	29%
Off-Peak	$ 22.89	$ 23.44	$ 22.65	23%
Total	$ 28.37	$ 28.25	$ 29.02	27%

- **Generation Sources** - PX unconstrained energy prices for March 2000 were about 53% higher than in March 1999 while the average ISO real-time price was about 43% higher than the same month last year. Most of these differences are due to changes in generation sources as well as increases in natural gas prices. Table 2 shows the average scheduled generation (measured based on Final Hour-Ahead Schedules) in March 2000 was less than March 1999 values by about 1%. However, the actual generation was 24,840 MWh and 25,815 MWh for March 1999 and 2000, respectively, resulting in a 4% increase in 2000 compared to 1999. Total generation scheduled from hydro decreased by a total of about 604 MW, a 17% reduction from March 1999, or a decrease of about 2% for total average Hour-Ahead Schedules.

Table 2: Generation Schedules by Source – March 1999 and 2000

Generation Source	Average Hourly MWh Mar-1999	Average Hourly MWh Mar-2000	Difference MW	Difference Percent
Hydro	3,585	2,981	-604	-17%
Nuclear/Coal	4,802	5.607	805	17%
Other Reg. Must-Take/Must Run	4,972	4,368	-604	-12%
Other Thermal	4,322	5,440	1,118	26%
Imports	8,053	7,304	-749	-9%
Exports	-1,364	-1,424	60	4%
Totals	24,370	24,276	-94	-1%

- **Price Volatility -** Energy price volatility in both the ISO real-time and PX energy markets was moderate. The real-time market had sixteen hours where prices exceeded $50/MWh, with a maximum price of $160.83/MWh occurring at HE 14 on March 14. Constrained PX energy prices exceeded $50/MWh for only three hours during the month, all three prices occurring for zone SP15 only. The maximum unconstrained PX energy price of $48.11/MWh occurred at HE 19 on March 19.

- **Natural Gas Prices** – The average daily natural gas spot price (at PG&E's Citygate) for March 2000 was $2.99/MMBtu, an increase of 15% from last month and a 56% increase over the March 1999 average spot price. Monthly contract prices in March were about 47% higher than a year ago. Higher spot market gas prices contributed to the higher energy prices in the PX and ISO markets compared to last March.

II. In the Ancillary Service Markets

Ancillary Service Prices

- The ISO continued to procure the bulk of A/S in the day-ahead market, with between 65% to 94% of A/S MW quantities being procured in the day-ahead market. The following table summarizes weighted average prices and procurements for March 2000 in both the day-ahead and hour-ahead markets.

	Day-Ahead Market	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$11.64	$11.26	$11.61	555	48	92%
Regulation Down	$ 9.71	$ 9.84	$ 9.72	555	36	94%
Spin	$ 2.87	$ 1.47	$ 2.72	611	71	90%
Non-Spin	$ .54	$ .57	$ .54	631	71	90%
Replacement	$ 1.40	$ .41	$ 1.05	239	128	65%

- The ISO's Ancillary Service markets had substantially fewer hours of zonal procurement in March compared to February, due mostly to lower congestion rates on Path 15/Path 26. This led to relatively small differences in average prices between zone NP15 and SP15. However, given that the predominant day-ahead congestion was N-S on Path 26, prices in zone SP15 were generally higher than prices in zone NP15. 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 (day-ahead and hour-ahead combined).

Summary of Weighted Day-Ahead A/S Prices by Zone and Period – March 2000

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$10.23	$12.10	$11.90	$14.46	8%
Regulation Down	$ 9.10	$11.68	$ 8.98	$12.42	1%
Spin	$ 3.73	$ 1.05	$ 3.89	$ 1.05	0%
Non-Spin	$ .53	$ .05	$ .97	$ .08	0%
Replacement	$ 1.05		$ 1.96		2%

- The $750 price cap was not reached in any of the A/S markets during the month. The maximum price in any of the A/S markets was a $249/MW regulation up price in the hour-ahead market. In the day-ahead market, the maximum price was $198.98/MW in the replacement reserve market. There were only two hours in the day-ahead A/S markets where prices exceeded $50/MW while the hour-ahead market experienced five hours with prices above that level.

Ancillary Service Costs

- A/S costs in March continued to be well below those experienced twelve months ago. Overall A/S costs were $11,433,021 or 2.0% 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**
January	$ .382	$ .62	2.0%
February	$ .359	$ .58	1.9%
March	**$ .369**	**$ .60**	**2.0%**

* 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 Ancillary Services Redesign measures: the Rational Buyer protocols and the separate pricing for Upward and Downward Regulation. These two measures have resulted in estimated savings of about $45.3 million since their implementation on August 17, 1999. This represents a saving of about 28% of total A/S costs during this time period. 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 decrease as the ISO procures less regulation service.

A/S Redesign Savings

	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%	$ 3,893,000	14%
September	$1,285,000	4%	$ 5,936,000	19%
October	$2,048,000	4%	$ 7,643,000	17%
November	$ 678,000	3%	$ 6,612,000	31%
December	$ 589,000	5%	$ 3,056,000	29%
January	$1,317,000	11%	$ 2,571,000	22%
February	$ 295,000	3%	$ 1,239,000	12%
March	$ 685,000	6%	$ 1,465,000	13%
Total	$12,897,000	8%	$32,415,000	19%

* Savings after implementation on August 17, 1999.

III. Inter-zonal Congestion Management Markets

- The congestion markets in March were characterized by lower import flows from the Northwest and higher import flows from the Southwest relative to March 1999. The significantly larger allocation of FTRs on the major southwest paths (Eldorado and Palo Verde) relative to the FTR allocations on COI and NOB may be one of the reasons for the relative shift of power flows into California.

Day-Ahead Market – Congestion Summary for March 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Import)	3%	1%	2%	$21.54	$27.50	$22.24
Palo Verde (Import)	24%	24%	24%	$13.88	$6.65	$11.43
Eldorado (Import)	2%	2%	2%	$1.27	$1.23	$1.26
Path 15 (S-N)	6%	20%	11%	$4.67	$4.29	$4.43
Path 26 (N-S)	23%	3%	16%	$7.76	$2.59	$7.46
Mead (Import)	8%	0%	6%	$5.28		$5.28

- Path 26 experienced both S-N and N-S congestion, however congestion was predominantly N-S at a congestion rate of 16%. Day-ahead congestion charges ranged from $.01/MW to $92/MW and averaged $7.46/MW.

- Path 15 congestion was slightly lower in March than in February 2000. Congestion (S-N) occurred for 6% of peak hours and 20% of off-peak hours compared to February's congestion rates of 11% and 16%, respectively. Day-ahead congestion charges on Path 15 ranged from $.01/MW to $13.52/MW and averaged $4.43/MW, up from the February level of $2.54/MW.

- Overall day-ahead congestion on the northwest paths decreased in March compared to February. On COI, day-ahead congestion occurred for the import direction during 3% of peak hours and 1% of off-peak hours, compared to the February congestion rates of 34% and 6%, respectively. A major portion of COI's congestion for the month occurred on March 18 due to planned maintenance. Congestion rates on NOB averaged 1% for peak and 0% for off-peak hours, respectively, compared to February 2000 rates of 9% and 0%, respectively. Average congestion charges on COI increased from $2.77/MW in February to $22.24/MW in March.

- March congestion on the southwest paths was mixed compared to February. Palo Verde was congested in the import direction for 24% of all hours in March, up from the February rate of 18%. Eldorado's congestion rate (import) decreased to 2% compared to February's 15%. March's average congestion prices for the Palo Verde and Eldorado were $11.43/MW and $1.26/MW, respectively, compared to February's average prices of $4.22/MW and $10.07/MW, respectively.

- Total congestion costs for March were $5,640,000 compared to March 1999 total costs of $6,230,000 and February 2000 costs of $3,286,000. The Palo Verde branch group accounted for about 50% of these costs in March 2000 while Path 26 accounted for another 35%.

IV. Performance of the FTR Market in March 2000

This report summarizes the performance of the FTR and Adjustment Bid markets in March 2000.

Secondary Market Activity

There were no secondary FTR market transactions reported in March 2000.

FTR Concentration

The following table summarizes FTR ownership and control concentration as of the end of March 2000. This table shows high ownership concentration on several important interfaces. The table also shows that a relatively small percentage (45%) of the FTRs have been assigned Scheduling Coordinators. The percentage is higher than February (28%) since the PX is now participating in FTR scheduling.

The FTR ownership and control (scheduling) concentration on some paths is high enough to deserve close scrutiny of scheduling behavior to ensure FTR ownership/control is commensurate with scheduling needs. The DMA is also monitoring the scheduling activities of entities with FTRs in the directions inconsistent with the location of their resources within the ISO control area, or in amounts exceeding their historical scheduling needs.

FTR Concentration

Branch Group	CFE IMP	COI IMP	ELD IMP	IID-SCE IMP	MEAD IMP	NOB IMP	PV IMP	P26 S-N	Silvpk IMP	VictVl IMP
FTR MW Auctioned	408	422	694	600	366	347	1,650	127	10	386
Max Single Ownership Concentration	47%	27%	59%	77%	64%	68%	37%	61%	90%	68%
FTR MW with SC Assignment	217	407	604	485	45	110	1,263	127	9	125
% FTR with SC Assignment	53%	96%	87%	81%	12%	32%	77%	100%	90%	32%
Max Single SC Concentration	25%	34%	59% (PX)	77% (PX)	7%	11%	36% (PX)	61%	90% (PX)	26%

Branch Group	CFE EXP	COI EXP	ELD EXP	IID-SCE EXP	MEAD EXP	NOB EXP	PV EXP	P26 N-S	Silvpk EXP	VictVl EXP	Total
FTR MW Auctioned	408	33	615	-	380	442	852	1,621	10	182	9,553
Max Single Ownership Concentration	43%	76%	49%	-	67%	43%	51%	62%	100%	50%	29%
FTR MW with SC Assignment	150	8	50	-	25	100	100	328	10	116	4,279
% FTR with SC Assignment	37%	24%	8%	-	7%	23%	12%	20%	100%	64%	45%
Max Single SC Concentration	25%	24%	8%	-	7%	11%	6%	19%	100%	50%	-

FTR Scheduling

The use of FTRs for scheduling priority increased in March compared to February. However, on most paths the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges. The frequency of schedule with FTR priority is indicated in the following table.

Branch Group	COI IMP	ELD IMP	IID-SCE	MEAD IMP	NOB IMP	PV IMP	Sil-Pk IMP	Total
MW FTR Auctioned	422	694	600	366	347	1,650	10	9,553
Avg. MW FTR Scheduled	44	294	279	6	1	741	8	1,373
% FTR Scheduled	10%	42%	46%	2%	-	45%	84%	14%
Max MW FTR Scheduled	165	455	328	10	25	875	9	-
Max Single SC FTR Schedule	100	405	328	10	25	600	9	-

As the peak summer season approaches the use of FTRs for their scheduling priority may increase.

Adjustment Bid Markets

The following table summarizes the performance of the Adjustment Bid market based on simulation runs for the period March 1-31, 2000.

Adjustment Bid Market Performance (March 1-31, 2000)

Path /Direction		MCR (MW)		ABSI (%)		Non-FTR Firm Schedule (MW)	
		Avg.	Min	Avg.	Min	Avg.	Max
COI	Import	183	56	278%	131%	0	0
ELDORADO	Import	1,179	907	1946%	838%	1	22
MEAD	Import	671	545	515%	235%	0	0
NOB	Import	1,697	1,623	2572%	2141%	0	0
PALOVRDE	Import	691	191	396%	21%	253	1,006
PATH15	S-N	1,484	917	419%	184%	469	890
PATH26	S-N	403	403	1065%	1065%	0	0
PATH26	N-S	2,117	1,036	896%	204%	51	668

Explanation of Table Entries:

MCR = Manageable Congestion Range is the depth of the Adjustment Bid market (in MW) with economic adjustment bids on both sides of the path, taking into account market separation constraints.

ABSI(%) = Adjustment Bid Sufficiency Index (expressed as %) is the ratio of MCR to the curtailed demand for transmission on the path

Non-FTR Firm Schedule = Schedules with no Adjustment Bids and not tied to ETCs or FTR scheduling priority

The value of 21% for minimum ABSI on Palo Verde is of concern. In general an ABSI of less than 100% will trigger investigation by DMA to determine if it is due to unexpected line outages, or phantom scheduling. The comfort zone from the DMA's perspective is a minimum monthly ABSI above 100% for all paths. We have investigated the specific hours where ABSI was less than 100% in March (hours 8 through 24 on March 13). The low ABSI values in these hours occurred on Palo Verde. The main reason for the low ABSI values was the high level of schedule curtailment due to the scheduled maintenance of the Palo Verde - North Gila line (scheduled from March 13 at 0600 through March 14 at 1500) to replace contacts on disconnects. Imports on the Palo Verde branch group were de-rated from 2,823 MW to 1,363 MW during this time.

We are developing a baseline for all of the above indices based on the historical levels for the period February 1, 1999 - January 31, 2000 (with no FTRs).

Conclusions

The observation of the FTR and Adjustment Bid markets in March 2000 indicate the following:

1. There has been no secondary FTR market activity.

2. With the PX starting its FTR scheduling process, more than 45% of the FTRs released in the primary auction have now been assigned Scheduling Coordinators.

3. The use of FTRs for their scheduling priority has been relatively small. Thus far FTRs have been used mostly to hedge against transmission price uncertainties.

4. FTR ownership and control concentration on some paths is quite high. These paths will be monitored closely for any unusual scheduling behavior during the high load periods.

5. The Adjustment Bid market for the majority of the paths does not seem to have been impacted by the FTR market so far. The depth of the Adjustment Bid market on some paths, however, is at a level that merits further analysis and scrutiny.

Issues Under Investigation

1. **Long-Term Price Cap Policy.** In the March Board discussion on Summer 2000 price caps, DMA informed the Board that an assessment of options on price caps was needed prior to the expiration of the ISO's current price cap authority on November 15, 2000. As we stated in our March report to the Board, a long-term price cap policy should be developed in conjunction with the market power mitigation element of congestion reform, rather than as a completely separate issue. Given the current timetable for the congestion reform process, we would anticipate implementation of the reforms early in 2001. We will evaluate options including one recommended by the Market Surveillance Committee to file for an extension of the ISO's current price cap authority until the long-term market power mitigation policy is in place. A recommendation for a long-term price cap policy will be brought to the Board in June along with the principles for congestion reform.

2. **Availability Standards**. The DMA is formulating a framework for defining generating unit availability standards and tracking unit availability. The FERC Order of 10/30/97 on California Restructuring contained directions for ISO and PX to set availability standard to mitigate market power by the IOUs. This requirement was issued in the context of PG&E, SCE, and SDG&E being the owners of extensive generating units in

California. Since then, these companies have divested themselves of significant numbers of their generating units. The DMA believes that generating unit availability standards remain an effective tool in market power monitoring and mitigation. The DMA is developing a conceptual framework for utilizing availability standards to monitor whether generating capacity is being purposefully withheld from the market, to encourage increased availability through appropriate market incentives, and to discourage capacity withholding through appropriate penalties. The DMA approach addresses both physical withholding and economic withholding. Availability standard can only be effective if there are appropriate sanctions to support them. The DMA anticipates a stakeholder process to discuss these possible mitigation measures as part of the overall market power mitigation element of congestion management reform.

3. **Congestion Management Reform and Redesign.** DMA developed the list of key questions on market design which need to be addressed in the stakeholder process and the criteria to evaluate alternative designs. The DMA will assist in the evaluation of the alternative designs. DMA is also developing market power mitigation measures to facilitate creation of new zones where workable competition may not prevail. The DMA approach is based on establishing unit-specific or area-specific bid caps that would be activated only for the hours (in the day-ahead, hour-ahead or real-time markets respectively) when congestion conditions lead to non-competitive congestion regions. The DMA is also investigating issues related to the integration of congestion management and ancillary services auction, as well as the integration of RMR dispatch in the forward market congestion management.

4. **PG&E Hydro Divestiture.** The DMA provided testimony to the California Public Utilities Commission on market power mitigation measures related to PG&E's proposed valuation of its hydroelectric generating resources. PG&E hydro assets serve as the largest supply of ancillary services and who owns them and how they can be used will have a significant impact on both energy and A/S market performance. The DMA identified market power mitigation measures that should be incorporated into the valuation of the hydro assets. We did not take a position on whether an auction, retention or some other method of market valuation is superior. The DMA continues its collaboration by providing responses to a number of questions in conjunction with its testimony.

5. **Path 26 Congestion.** At the request of the Board, DMA conducted an analysis of congestion on Path 26 as an inter-zonal interface (for February-March 2000), compared to similar periods in 1999 when Path 26 was an intra-zonal interface. The analysis included the comparison of congestion frequency, usage charge, as well as the usage charge per MWh of schedule curtailment (UCMC). The UCMC is used as an indicator to determine whether or not there has been a significant change in bidding strategy as a result of converting Path 26 to an inter-zonal interface. A relatively constant UCMC would indicate that any shift in demand for the use of Path 26 has been accompanied by a commensurate increase in price (usage charge). This would be the expected observation if there were little or no change in the demand curve for transmission before and after conversion of Path 26. A significant change in UCMC would however indicate a change in bidding strategy that would merit further analysis. Surrogate usage charges were worked out for Path 26 for February and March 1999 (when Path 26 was intra-zonal), as the difference between the maximum incremental dispatch bid price and the minimum decremental dispatch bid price.

   The analysis showed that Day-ahead congestion on Path 26 in February 2000 occurred with about the same frequency as did real-time congestion on Path 26 in February 1999. However, day-ahead congestion on Path 26 was more frequent in March 2000 versus real-time congestion in March 1999. The average usage charges were substantially higher in 1999 versus 2000. However, there was less difference in the average usage charge per MWh of curtailment (UCMC). This indicates an increased demand for the use of Path 26 without major change in bidding strategy, at least initially.

6. **RMR Designation Process for Year 2001**. The DMA collaborated with the ISO Transmission Planning staff to incorporate market considerations into the RMR designation process. These considerations include the amount of market generation that may be relied upon with a high level of certainty, and the ability to mitigate local market power, A methodology was developed and tested on a limited basis in a case study to demonstrate how the methodology may be applied and the potential impacts of incorporating this approach into the RMR selection process. Results of this effort were presented and discussed with stakeholders at the April 11 LARS meeting. A more detailed description of the general approach being proposed by DMA and case study results are presented under a separate tab in the Board material.