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: May 12, 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 April 2000.

APRIL HIGHLIGHTS

Two major events created significant volatility in the ISO markets in April: very low amounts of thermal generation on-line in SP15 and implementation of the new target price methodology in the real time energy market on April 5.

Of the over 11,000 MW of thermal capacity owned by non-utilities in SP15, nearly two-thirds was off-line in April: about 11% was out for maintenance, while another 54% of non-utility thermal capacity was kept off-line during April. In addition, a number of out-of-control area generating units supplying SP15 were also off-line for maintenance in most of April, including Mojave #1 and Palo Verde #3. Current limitations on the scheduling and dispatch of import supplemental energy bids (which must be dispatched at least 20 minutes before the hour) in the real time market also contributed to these supply problems.

Average prices in the real-time and PX markets tracked closely during off-peak hours, but prices in the ISO real time market during peak hours were about 20% higher than average constrained PX price in SP15, and about 7% higher than PX prices in NP15 during peak hours. Price differentials between peak and off-peak periods widened in both markets, due, in part, to a combination of more hydroelectric generation and, for the real time market, the new target price methodology. The price cap of $750/MWh was reached in the real time market for the first time ever in zone SP15 on April 26.

A new target price methodology was implemented to deter gaming opportunities occurring under the previous methodology. This resulted in significantly more price volatility in the real-time market, with about 22% of the hours having prices at $0/MWh or less. The frequency of very low real time prices appears to have impacted capacity prices in the regulationup market, which increased significantly following implementation of the new target price methodology. At the end of April, there was evidence that the real-time market was adjusting to the new target price methodology, so that both uninstructed generation and the frequency of zero prices has begun to decline.

Ancillary service prices experienced increased volatility in zone SP15, particularly in the regulation up market. Ancillary service costs as a percentage of total energy costs rose to 3.4% in April from 2% in March, but were still down substantially from 8.5% last April.

The major trend in the congestion markets continued to be significant N-S congestion on Path15/Path26 with a substantial lessening of congestion on the Southwestern paths. Path 26 remained congestion during 16% of hours, but both Palo Verde and Eldorado did not experience any day-ahead congestion.

KEY MARKET CONDITIONS FOR APRIL 2000

I. In the California Wholesale Energy Markets

- **Loads -** April 2000 system energy loads totaled 18,212 GWh (or 25,330 average hourly MW), a 4.8% increase over April 1999 loads. Daily peak loads averaged 29,468 MW, 5.3% higher than average daily April 1999 peak loads. The peak load for the month was 33,013 MW for hour ending 15 on April 26.

- **Wholesale Energy Prices** – The differences between peak and non-peak average energy prices continued to widen for both real time prices and constrained PX prices for April compared to a year ago (see Table 1 below). The most significant event in the energy markets was implementation of the new target price methodology in the ISO real time market. This change has produced the following results:

  - Price volatility of the real time market increased significantly, roughly double that of previous months.

  - There were a large number of hours, both peak and off-peak, where the real time price equal was at or below $0/MWh. Since the April 5 implementation date, there have been 141 hours (23%) in NP15 and 133 hours (22%) in SP15 where the real time price was $0/MWh or less.

  - Regulation up capacity prices on NP15 have increased about 50%, which is likely due in large part to the high number of zero priced hours in the real time market. However, there has not been decrease in regulation down capacity prices.

  - Recent trends in the real time market indicate that price volatility may be decreasing along with significant reductions in the number of hours where prices are zero or less.

  - Uninstructed generation appears to have decreased recently as continued under-scheduling of load is being met predominantly through real time instructed generation.

- Another significant trend in the energy markets was the large amount of thermal generation in SP15 that was off-line in April, exacerbating some of the recent supply shortages in both the real time and ancillary service markets. Of over 11,000 MW of thermal capacity owned by non-utilities in SP15, about 11% was out for maintenance, while another 54% of thermal capacity was off-line during April. In addition, a number of other out-of-control area generating units supplying SP15 were off-line for maintenance in most of April, including Mojave #1 and Palo Verde #3.

- One of the problems that has contributed to the price spikes in the real- time market are the scheduling constraints associated with supplemental energy import bids. Since all supplemental energy bids over the interties are dispatched no later than 20 minutes before a given hour, it is often difficult to dispatch the optimum amount of supplemental energy to minimize real- time energy costs. Therefore, additional imports of supplemental energy cannot be called during the hour due to the scheduling protocols. This constraint often results in the situation where many supplemental energy import bids, with prices lower than the ex-post price, will go unused having not been dispatched prior to the hour. With the implementation of 10 minute settlements in August, this will allow dispatch of supplemental energy imports for 10 minute intervals.

- Prices in both the real-time and zonal PX energy markets were significantly higher in SP15 than NP15. This is due to congestion patterns in both the day ahead and real time markets where there was north to south congestion on Path 15/Path 26 throughout the month. The PX day-ahead market was split during 29% of the hours in April 2000 resulting in constrained PX prices in SP15 being about 16% higher than NP15 prices. The real time market was split in 7% of the hours with April prices in SP15 averaging about 32% higher than prices in NP15.
- Overall, the year to year change in average prices in both energy markets in April 2000 (compared to April 1999) were smaller than the price changes experienced earlier this year. April 2000 real time price levels were 10% higher in NP15 and 44% higher in SP15 compared to April 1999. Constrained PX prices were 9% higher in NP15 and 26% higher in SP15 compared to the levels experienced in April 1999. This compares to January 2000 real time prices being up 69% and 61%, respectively, for zones NP15 and SP15 relative to January 1999. January 2000 constrained PX prices were up 44% and 42% for zones NP15 and SP15, respectively, compared to January 1999 levels.

Table 1: Energy Price Summary for April 2000

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$ 39.86	$ 33.18	$ 46.54	$ 33.18	10%
Off-Peak	$ 17.21	$ 17.21	$ 17.21	$ 17.21	0%
Total	$ 32.33	$ 27.87	$ 36.79	$ 27.87	7%
PX Constrained					
Peak	$ 34.50	$ 30.98	$ 37.37	$ 35.15	37%
Off-Peak	$ 17.28	$ 17.45	$ 17.20	$ 17.19	13%
Total	$ 28.78	$ 26.48	$ 30.67	$ 29.18	29%

- **Price Volatility -** Energy price volatility in the PX energy markets remained the same as previous months whereas volatility in the real time energy prices roughly doubled due to the change in the target price methodology.
- The ISO real time market experienced a $750/MW price cap hit in zone SP15 at hour ending 14 on April 26. Constrained PX energy prices did not exceed $50/MWh in zone NP15 while there were 38 hours in zone SP15 where the price exceeded $50/MWh, reaching a maximum of $250/MWh at hours ending 20 & 21 on April 30.
- **Energy Price Levels** - Average PX unconstrained and ISO real time market prices are up 11% and 27%, respectively from April 1999 levels. This represents a narrowing of the large year-to-year differences experienced over the last several months. Contributing to these differences are: (1) Hydro generation in April 2000 was about 75% of April 1999 levels, and (2) average daily natural gas spot prices are up 38% over a year ago.

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 68% to 96% of A/S MW quantities being procured in the day-ahead market. The following table summarizes weighted average prices and procurements for April 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	$ 22.10	$ 21.28	$ 22.04	554	46	92%
Regulation Down	$ 12.25	$ 8.55	$ 12.11	554	22	96%
Spin	$ 4.65	$ 7.55	$ 5.01	558	80	87%
Non-Spin	$ .12	$ 5.49	$ .62	657	67	91%
Replacement	$ 1.17	$ .46	$ .94	154	74	68%

- The ISO's Ancillary Service markets had more hours of zonal procurement in April compared to March, due primarily to N-S congestion on Path 26 and Path 15 to a lesser extent. This congestion led to significantly higher regulation up prices in SP15 than 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).

- Regulation up capacity prices are up 50% in April compared to March. Part of this increase is due to the large number of units off-line in SP15. In addition, since regulation up energy dispatch is paid the ex-post price, bidders appear to have raised regulation up capacity prices to compensate for the numerous hours during real time when energy prices were at or below $0/MWh. This is evidenced by zone NP15 regulation up capacity prices increasing by 50% in April over March, given that all zonal procurement of regulation up took place with N-S congestion on Path 15/Path 26. There was no corresponding decrease in regulation down capacity prices based on the events in the real time energy market.

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

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$ 15.58	$ 16.81	$ 36.40	$ 24.98	15%
Regulation Down	$ 10.16	$ 17.98	$ 10.79	$ 17.46	2%
Spin	$ 4.56	$ 1.15	$ 10.61	$ 1.52	3%
Non-Spin	$ .22	$ .02	$ .16	$ .03	2%
Replacement	$ .98		$ 1.80		5%

- The $750 price cap was not reached in any of the A/S markets during the month. The non-spin market experienced the highest prices during the month with a $478/MW price in the hour ahead market. In the day-ahead market, the maximum price was $175/MW in the regulation up market in zone SP15. In total, there were sixteen hours in the regulation up market where the price exceeded $150/MW in zone SP15.

Ancillary Service Costs

- A/S costs in April were roughly half of the levels experienced twelve months ago, however costs were up almost 70% compared to levels in previous months. The main reason for the increase were the very high ancillary service prices in zone SP15, particularly in the regulation up and spin markets, during periods of zonal procurement in both the day ahead and hour ahead markets. Most of these costs were incurred over the last few days of the month. Ancillary costs may have increased, in part, due to the new target price methodology, Overall A/S costs for April totaled $17,292,474 or 3.4% 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%
April	**$ .576**	**$ .95**	**3.4%**

* 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 $50.3 million since their implementation on August 17, 1999. This represents a saving of about 27% of total A/S costs during this time period. Significant 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. During April 2000 there were a significant number of hours where SP15 experienced very high regulation up prices combined with low regulation down prices. The differences in these two prices produced the usually high regulation savings estimate for April.

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%
April	$ 854,000	5%	$ 4,242,000	24%
Total	$13,751,000	7%	$36,658,000	20%

* Savings after implementation on August 17, 1999.

III. Inter-zonal Congestion Management Markets

- The congestion markets in April showed continued N-S congestion patterns on Path 15/Path 26 and a marked decrease in congestion across Southwest paths. The following table summarized congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for April 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Import)	6%	4%	5%	$11.64	$2.07	$9.31
Path 15 (N-S)	13%	9%	0%	$32.52	$0	$32.52
Path 26 (N-S)	24%	0%	16%	$9.41	$4.09	$9.36
Path 15 (S-N)	1%	13%	5%	$3.02	$2.08	$2.19
Summit (Import)	1%	3%	2%	$1.34	$3.28	$2.31
Mead (Import)	19%	3%	14%	$6.07	$.65	$5.69

- Path 26 experienced both S-N and N-S congestion, however almost all congestion was in the N-S direction. The overall congestion rate remained at 16%, unchanged from March 2000. Day-ahead congestion charges ranged from $.02/MW to $92.70/MW and averaged $9.41/MW, a moderate increase from last month.

- Path 15 congestion was down in April compared to March 2000. Congestion (S-N) occurred for 1% of peak hours and 13% of off-peak hours compared to March's congestion rates of 6% and 20%, respectively. Day-ahead congestion charges on Path 15 ranged from $.81/MW to $212.36/MW and averaged $32.52/MW, up significantly from the March level of $9.46/MW.

- Overall day-ahead congestion on the northwest paths increased in April compared to the very low levels in March. On COI, day-ahead congestion occurred for the import direction during 6% of peak hours and 4% of off-peak hours, compared to the February congestion rates of 3% and 1%, respectively. Congestion rates on NOB averaged 20% for peak and 0% for off-peak hours, respectively, compared to March 2000 rates of 1% and 0%, respectively. Average congestion charges on COI decreased from $22.24/MW in March to $9.31/MW in April.

- April congestion on the southwest paths was down significantly compared to March. Palo Verde did not experience any day ahead congestion during the month, probably due, in part, to Palo Verde Unit #3 being off-line for refueling starting April 1. In addition, higher loads in the southwest may led to reduced imports into California. Similarly, there was no congestion on the Eldorado branch group as well, compared to the March congestion rate (import) of 2%. Mead was the only major southwest path that experienced congestion, with a congestion rate of 14%, compared to the March level of 6%. Average congestion prices for Mead in the peak and off-peak periods were $6.07/MW and $.65/MW, respectively, compared to average prices in March of $5.28/MW and $0/MW, respectively.

- Total congestion costs for April were $6,300,000 up from the $5,640,000 last month and April 1999 total costs of $2,430,000. Path 26 costs totaled $2,430,000 while Path 15 costs for April were about $1,480,000 million, up from last year's costs of $28,000.

IV. Performance of the FTR Market in April 2000

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

FTR Concentration

The following table summarizes FTR ownership and control concentration as of the end of April 2000. This table shows high ownership concentration on several important interfaces. The table also shows that a relatively small percentage (41%) of the FTRs have been assigned Scheduling Coordinators.

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	VictVI 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	312	513	485	35	85	1,163	127	9	125
% FTR with SC Assignment	53%	74%	74%	81%	10%	24%	70%	100%	90%	32%
Max Single SC Concentration	25%	27%	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	VictVI 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	3,958
% FTR with SC Assignment	37%	24%	8%	-	7%	23%	12%	20%	100%	64%	41%
Max Single SC Concentration	25%	24%	8%	-	7%	11%	6%	19%	100%	50%	-

FTR Scheduling

The attachment of FTRs to schedules for scheduling priority decreased in April compared to March. 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 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	68	209	380	3	2	417	9	1,088
% FTR Scheduled	16%	30%	63%	1%	1%	25%	90%	11%
Max MW FTR Scheduled	150	250	444	10	37	520	9	-
Max Single SC FTR Schedule	100	200	444	10	37	400	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 February – March 1999 vs. 2000.

Adjustment Bid Market Performance (Feb – March, 1999 vs. 2000)

Path /Direction		1999				2000			
		MCR (MW)		ABSI (%)		MCR (MW)		ABSI (%)	
		Avg.	Min	Avg.	Min	Avg.	Min	Avg.	Min
COI	Import	814	244	545%	180%	1362	56	563%	60%
ELDORADO	Import	1003	663	773%	119%	1336	845	585%	194%
MEAD	Import	-	-	-	-	636	329	538%	235%
NOB	Import	1677	1032	1040%	89%	1226	344	584%	131%
PALOVRDE	Import	852	133	1116%	36%	894	44	502%	32%
PATH15	S-N	1638	1127	322%	225%	1595	78	495%	21%
PATH15	N-S	605	249	581%	164%	154	136	711%	371%
PATH26	S-N	-	-	-	-	410	384	912%	567%
PATH26	N-S	-	-	-	-	2082	426	902%	141%

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

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.

Conclusions

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

1. More than 41% of the FTRs released in the primary auction have now been assigned Scheduling Coordinators.
2. 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.
3. 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.
4. The depth of the Adjustment Bid market on some paths is at a level that merits further analysis and scrutiny. The comparison of Adjustment Bid Sufficiency in the two months (February and March) of 1999 and 2000 shows a small reduction of Adjustment Bid Sufficiency on the average.

Issues Under Investigation

1. **Investigation of Possible Physical and Economic Capacity Withholding.** Following FERC's order of April 12, 2000 rejecting ISO's OOM Rehearing Request, several cases of potential physical withholding (unit outages) and economic withholding (bids at or near the $750 price cap) have been observed which have had significant financial impacts. The DMA is investigating the situation and will use its authority in the MMIP provisions of the ISO tariff to recommend appropriate action.

2. **Availability Standards**. The DMA is formulating a framework for defining generating unit availability standards and tracking unit availability. 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 standards can be effective only if there are appropriate sanctions to support them. The DMA is involved in the current congestion reform stakeholder process discussing these possible mitigation measures as part of the overall market power mitigation element of congestion reform.

3. **Congestion Management Reform and Redesign.** Market power mitigation is a common requirement of all proposals. The DMA is developing market power mitigation measures that would facilitate locational price signals 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 (or local requirements) lead to non-competitive supply requirements. 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. The DMA will be evaluating alternative design proposals with respect to their ability to promote market efficiency, provide consistent market incentives, and adequately address market power concerns..

4. **Collaboration with the PX in Investigation of Potential Anti-market Behavior.** The DMA is collaborating with the PX under the terms of the Market Monitoring provisions of the ISO and PX Tariffs to help the PX in the investigation of two incidents that may be in violation of the code of conduct and could have had a material impact on the market.

5. **Target Price.** The DMA has adopted a three-pronged approach to addressing the issues raised by implementation of a new target price. As a short term option, DMA is recommending the development of the ability and criteria for mitigating strategic bids that are obvious attempts to manipulate the ISO's market price by screening these out from use in calculating the target price. This approach would allow use of the previous target price methodology, and could be implemented on a relatively short-term time frame. Longer-term options that could be implemented after 10-minute settlements is implemented in August are also being identified and assessed. Finally, DMA is monitoring impacts and market adjustments to the new target price methodology in order to assess the magnitude of the potential benefits and need for different short and longer-term alternatives being developed.