Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers

Date: May 18, 2001

Re: Market Analysis Report for March/April 2001

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

This report summarizes key market conditions, developments, and trends for March and April 2001.

EXECUTIVE SUMMARY

Real time electricity and ancillary service prices remained high in March and April despite decreased load in California. There were a number of factors contributing to higher prices including: high spot natural gas prices, tight supply conditions caused by unit outages, lack of imports, and exercise of market power by sellers. In addition, there is continued financial uncertainty surrounding payment for sellers of energy such as Qualifying Facilities in the California market. On average, the price of real time electricity in March decreased 14% to $313/MWh from the February average of $363/MWh. However, prices rose again in April as the average price of real time electricity increased by 18% over March prices to $370/MWh. Loads continue to decline and there appears to be visible conservation efforts with total load in March down 8.2% from February and down 5.97% from last March. Total load in April decreased 3.47% from March and 5.34% from April of last year. Pursuant to its December 15, 2000 Order, the FERC issued orders for potential refunds totaling approximately $125 million for hours with Stage 3 emergencies during January, February, and March. DMA estimates that real time supply costs from sales by non investor-owned suppliers for the three months excess of levels that might be deemed just and reasonable under current market conditions of just over $1 billion. About $302 million of these sales were directly from FERC jurisdictional sellers. No order has been issued as of this date regarding purchases in December 2000 at prices above the $250/MWh soft price cap.

The California Energy Resources Scheduling division of the California Department of Water Resources (CERS) continues to purchase the net short position of the California investor-owned utility loads. In March and April there was an increase in purchases of energy by the CDWR to cover the IOU's "net short" position. Forward energy purchases by CDWR have reduced the underscheduling of loads from an average of 10 percent in February to an average of 6 percent in March and April.

Regional spot electricity prices continued to be high in March and April, with hydro conditions in the Northwest at about 50% of normal, tight supply conditions caused by planned and unplanned outages for Western region resources, and continued high natural gas prices.. Overall, regional prices reported in the Northwest were 24% lower than "effective real time energy prices" in NP15, while regional prices reported in the Southwest were 21% lower than "effective average real time energy prices" in SP15. Since the trading volume at the reported regional spot prices is unknown, it is difficult to make direct comparison to

California volume and spot prices. There is concern that low Northwest hydro conditions will affect California prices this summer as available imports from the Northwest are expected to be significantly below recent years' levels during the summer peak.

California average spot natural gas prices decreased from $15/MMBtu in February to $12/MMBtu in March due to milder weather conditions leading to less heating demand. Average natural gas prices increased in April to $13/MMBtu primarily due to high demand from gas fired generators. Again, it is difficult to determine the volumes transacted at these high spot natural gas prices. The price for NOx emissions credits continued to declined in March and April due in large part to actions taken by the SCAQMD that effectively limits the price of credits to electric generators to $7.50/RTC. This should provide some relief to the California electricity market going forward as credit prices last summer ranged from $30/RTC to $60/RTC. The March 8, 2001 Cantor Fitzgerald Market Price Index decreased to $33.42/RTC from the last reported index price of $42.69/RTC released in December. The weighted average price of recent trades reported by Cantor Fitzgerald on May 4, 2001 was down further to $18.00/RTC. New rules recently placed in effect in the SCAQMD region have drastically changed the RECLAIM trading credit costs to electric generators over 50MW retroactively to January 11, 2001. The new rules result in generators in the SCAQMD region being charged a fixed mitigation fee of $7.50/lb of NOx emissions that are emitted in excess of their current RTC holdings.

Other key market activities include the following:

- **Lower Ancillary Service Prices.** In March prices were generally lower when compared to February. Total ancillary service costs were $179 million in March, down from the February total of $186 million, representing a decrease from $11.27 to $10.04 per MWh of load served. Ancillary service prices in April were comparable to those in March. Total April ancillary service costs were $172 million in April, down from the March total of $179 million, representing a decrease from $10.04 to $10.00 per MWh of load served.

- **Lower Congestion Cost.** Congestion in March was primarily limited to exports to the Northwest on COI and NOB and south to north congestion on Path 15. Total congestion costs for March were $14.2 million. Congestion was reduced in April but still present on exports to the Northwest on COI and NOB and south to north on Path 26 and Path 15. Total congestion costs for April were $10.5 million.

KEY MARKET CONDITIONS FOR MARCH AND APRIL 2001

I. California Wholesale Energy Markets

- **Loads.** The results of conservation efforts by California consumers were seen in lower monthly system energy loads for March totaling 17.9 GWh , a 6% decrease from March 2000 and a 2.3% decrease in daily averages from February 2001 due to milder temperatures. The peak load for the month reached 29,567 MW, an 8.6% decrease from March 2000 levels, occurring at HE 19 on March 5. Daily peak loads averaged 28,225 MW, a 7.1% decrease from March 2000.

  April energy loads decreased from March due to continued mild temperatures. Monthly system energy loads totaled 17.2 GWh in April, a 5.34% decrease from April 2000 and a 3.47% decrease from March 2001. The peak load for April reached 31,430 MW, a 4.8% decrease from April 2000 levels, occurring at HE 15 on April 25. Daily peak loads averaged 27,596 MW, a 6.35% decrease from April 2000.

- **Wholesale Energy Prices.** On December 31, the soft cap was decreased from $250/MWh to $150/MWh, allowing as- bid payments above $150 with these payments being subject to scrutiny and refund if not justified on a cost-basis. The as-bid structure and continued reliance on out-of-market purchases has created several prices and volumes related to the real time market. The BEEP market now consists of the market clearing price (MCP) and quantity for bids under the price cap, as well as the as-bid price and volume for bids accepted over the price cap. Out-of-market purchases are added to the MCP and as-bid prices to yield the total "effective real time price." OOM costs include CERS purchases on behalf of the IOU's, which comprised approximately 95 percent of out-of-market purchases between February and April. Averages for these different segments of total real time purchases for peak, off-peak, and all hours are reported below:

Table 1a: Real Time Energy Price Summary for March 2001

	Market Clearing Avg. Price and Total Volume (1)	As-bid Avg. Price and Total Volume (2)	Total BEEP* Avg. Price and Total Volume (3)	Out-of-market Avg. Price and Total Volume (4)	"Effective Real Time Avg. Price" and Total Volume (5)	Total System Loads and Percent Under-scheduling
Peak	$121.82 (81 GWh)	$447.41 (140 GWh)	$327.81 (221 GWh)	$319.69 (1,622 GWh)	$320.66 (1,843 GWh)	12,889 GWh 8%
Off-peak	$67.94 (-3 GWh)	$395.22 (110 GWh)	$387.86 (108 GWh)	$280.14 (636 GWh)	$295.71 (744 GWh)	4,968 GWh 4%
All Hours	$120.19 (79 GWh)	$424.43 (250 GWh)	$347.46 (329 GWh)	$308.55 (2,259 GWh)	$313.49 (2,587 GWh)	17,857 GWh 6%

Includes quantities purchase at MCP and as-bid purchases above $150.

Table 1b: Real Time Energy Price Summary for April 2001

	Market Clearing Avg. Price and Total Volume (1)	As-bid Avg. Price and Total Volume (2)	Total BEEP* Avg. Price and Total Volume (3)	Out-of-market Avg. Price and Total Volume (4)	"Effective Real Time Avg. Price" and Total Volume (5)	Total System Loads and Percent Under-scheduling
Peak	$33.61 (-64 GWh)	$321.25 (48 GWh)	$156.58 (-16 GWh)	$385.93 (1,342 GWh)	$383.18 (1,326 GWh)	12,390 GWh 7%
Off-peak	$12.82 (-33 GWh)	$260.37 (28 GWh)	$124.97 (-6 GWh)	$338.39 (522 GWh)	$336.08 (516 GWh)	4,867 GWh 2%
All Hours	$26.52 (-97 GWh)	$299.06 (75 GWh)	$148.38 (-22 GWh)	$372.62 (1,864 GWh)	$369.98 (1,842 GWh)	17,257 GWh 6%

* Includes quantities purchase at MCP and as-bid purchases above $150.

- Average real time prices decreased in March 14% compared to February; however, prices increased again in April by 18% compared to March. Although total loads in March increased from February, average hourly underscheduling decreased as a percent of load from 10% to 6%. April total loads were slightly lower than March loads and average hourly underscheduling remained constant at 6%. Contributing to the monthly prices differences in real time prices was a decrease in the average spot price for natural gas from $14.73/MMBtu in February to $11.63/MMBtu in March followed by an increase to $12.85/Mmbtu in April.

II. Ancillary Service Markets

Ancillary Service Prices

- The five ancillary services are procured through a day-ahead and an hour-ahead market to meet reserve requirements. Effective December 31, 2000 through the end of May 2001, a $150/MW soft price cap is in effect for capacity payments for the ancillary services. Reserve requirements that are not met at prices at or below the soft cap are purchased at the bid price and are subject to just and reasonable cost review. There was a change in the payment of Replacement Reserve Capacity which distinguished between reserve service and energy being provided beginning December 31, 2000.Capacity payments for Replacement Reserve are refunded to the ISO if the reserves are dispatched in real- time. The resulting savings have ranged from $10 million to $20 million per month.

- The California investor-owned utilities continued to self provide a portion of their A/S requirements. The volume reported in Table 2 includes the IOU's self provision of A/S.

- Average prices for ancillary services were mixed in March, on average, compared with February 2001. Regulation Up prices decreased by more than 8% while Regulation Down prices increased by 8%. Prices for both Spinning Reserve and Non-spinning Reserve increased by 35% and 30% respectively while Replacement Reserve prices decreased by 12%. Between 70% and 92% of requirements were purchased in the day-ahead market. Table 2a below summarizes the weighted average prices and quantity procured for March 2001 in both the day-ahead and hour-ahead markets.

April ancillary service prices increased on average compared to March 2001. Although Regulation Up prices decreased by 33%, Regulation Down, Spinning Reserve, Non-spinning Reserve, and Replacement Reserve prices all increased by 32%, 88%, 14%, and 10% respectively. Between 78% and 94% of requirements were purchased in the day-ahead market. Table 2b below summarizes the weighted average prices and quantity procured for April 2001 in both the day-ahead and hour-ahead markets.

- Tables 3a and 3b compare the 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) for March and April 2001.

Table 2a. Summary of Weighted Day-Ahead A/S Prices by Market – March 2001

	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	$ 138	$252	$ 162	301	132	70%
Regulation Down	$ 42	$ 45	$ 43	607	79	89%
Spin	$ 40	$ 57	$ 41	755	70	92%
Non-Spin	$ 61	$ 66	$ 62	672	114	85%
Replacement	$ 112	$ 83	$ 110	284	47	86%

Table 2b. Summary of Weighted Day-Ahead A/S Prices by Market – April 2001

	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	$ 99	$134	$ 109	345	96	78%
Regulation Down	$ 57	$ 46	$ 56	681	79	90%
Spin	$ 77	$ 75	$ 77	1043	64	94%
Non-Spin	$ 74	$ 47	$ 70	826	94	90%
Replacement	$ 129	$ 78	$ 121	487	33	94%

Table 3a. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – March 2001

	NP15		SP15		Percent of Hours with
	Peak	Off Peak	Peak	Off Peak	Zonal Procurement
Regulation Up	$ 79	$ 115	$ 233	$ 243	0%
Regulation Down	$ 29	$ 75	$ 29	$ 81	0%
Spin	$ 52	$ 12	$ 53	$ 16	0%
Non-Spin	$ 73	$ 15	$ 127	$ 57	0%
Replacement	$ 120	$ 34	$ 153	$ 113	0%

Table 3b. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – April 2001

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$ 71	$ 80	$ 147	$ 155	0%
Regulation Down	$ 49	$ 80	$ 43	$ 105	0%
Spin	$ 97	$ 47	$ 91	$ 48	0%
Non-Spin	$ 86	$ 24	$ 105	$ 49	0%
Replacement	$ 131	$ 73	$ 142	$ 102	0%

Ancillary Service Costs

- A/S costs in March were $179 million compared to the February total of $186 million. March A/S costs were about 4.2% of total energy costs. In April, A/S costs decreased to $172 million. April A/S costs were also about 4.2% of total energy costs.

TABLE 4. Summary of Average Ancillary Service Cost by Month

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%
December	$ 14.161	$ 22.65	7.5%
January	$ 7.845	$ 12.96	5.9%
February	$ 6.650	$ 11.27	4.5%
March	**$ 5.783**	**$ 10.04**	**4.2%**
April	**$ 5.746**	**$ 10.00**	**4.2%**

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

III. Out of Market Calls (OOM)

March and April out-of-market calls remained high largely due to purchases by CERS in real-time being recorded as OOM. CERS purchases accounted for approximately 95% of all OOM purchases between February and April. The average out-of-market costs for April were $397/MWh, up $59/MWh compared with the March average of $338/MWh. On an hourly average basis, 3,035 MW were purchased out of market in March and 2,588 MWh were purchased out of market in April, with 70% of the OOM electricity coming from imports in each month. The total cost of out -of-market purchases in March and April were $738 million and $722 million.

Figure 1. Quantities of Out-of-market Purchases Average Hourly for August 2000 - April 2001

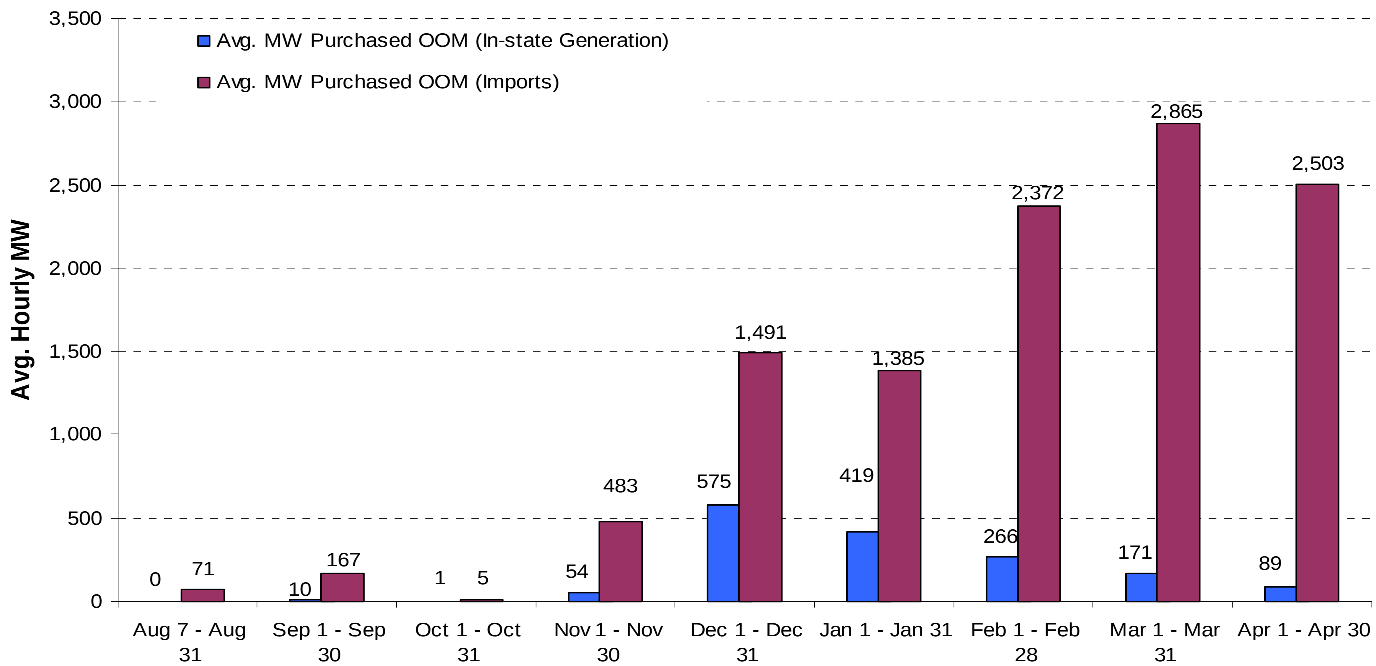


Figure 2. Comparison of Average Costs for Out-of-market and Real Time MCP August 2000 - April 2001

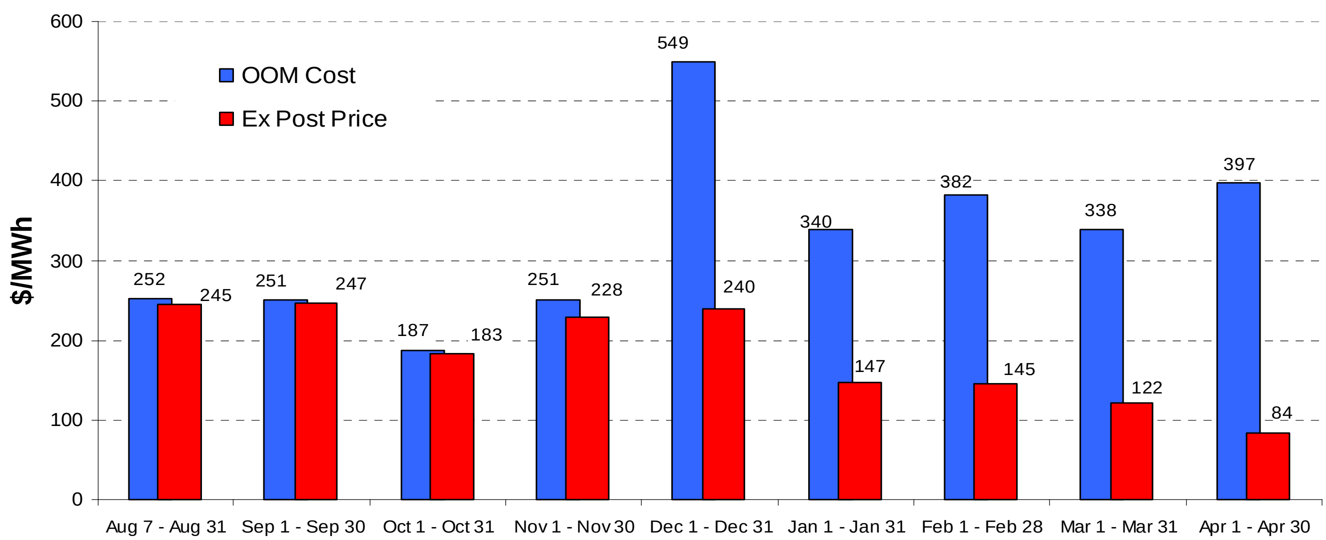
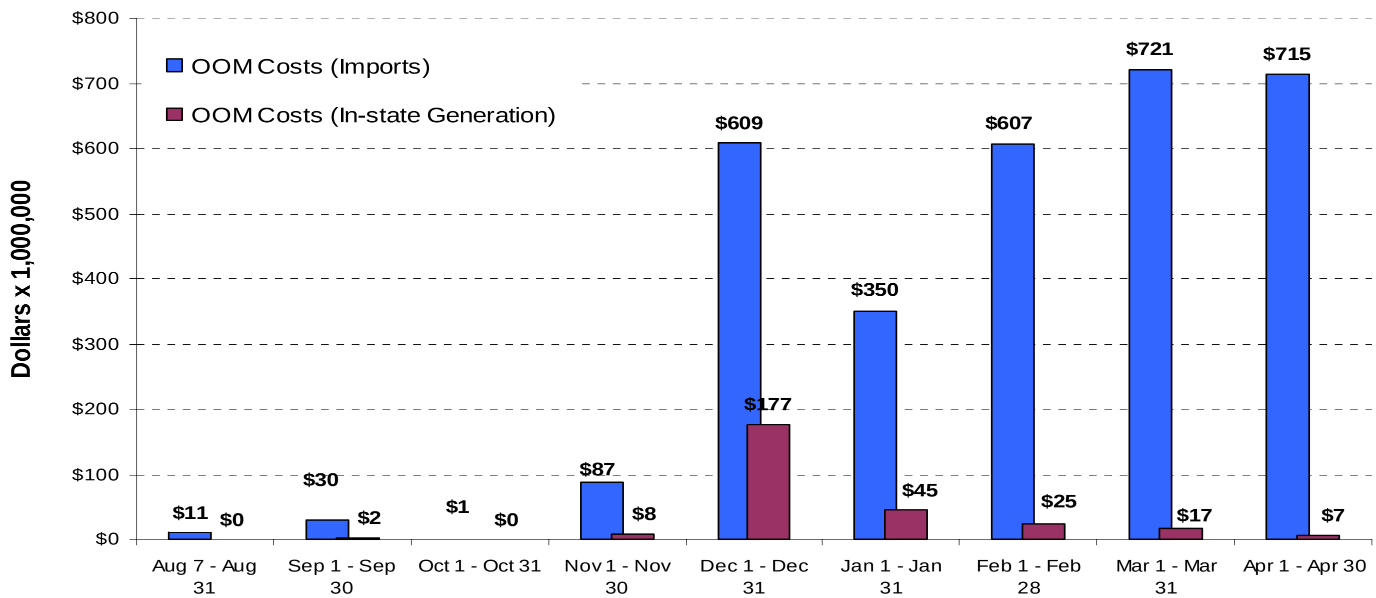


Figure 3.Total Out of Market Costs (in millions of $)
August 2000 - April 2001



IV. Inter-zonal Congestion Management Markets

- Congestion in March was limited to exports to the Northwest and south to north congestion on Path 15. Export congestion to the Northwest increased considerably on NOB compared with February. Path 15 experienced significantly reduced congestion in the south to north direction. Congestion decreased in April but was still present on exports to the Northwest on COI and NOB and south to north on Path 26 and Path 15. Total congestion costs for April were $10.5 million.

The following tables summarize congestion rates and average congestion charges by branch group for the day-ahead market for March and April.

Day-Ahead Market – Congestion Summary for March 2001

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Export)	23%	72%	39%	$95.94	$42.86	$63.36
NOB (Export)	65%	90%	73%	$38.09	$28.99	$34.38
Path 26 (S-N)	1%	8%	3%	$93.99	$108.74	$105.79
Path 15 (S-N)	5%	6%	5%	$19.21	$16.01	$18.01

Day-Ahead Market – Congestion Summary for April 2001

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
COI (Export)	9%	6%	8%	$118.54	$146.01	$125.53
NOB (Export)	43%	54%	47%	$32.68	$103.20	$59.68
Path 26 (S-N)	4%	43%	17%	$32.61	$53.55	$50.43
Path 15 (S-N)	4%	6%	5%	$4.35	$10.68	$6.99

- Total congestion costs for March were about $14.2 million, a substantial decrease over the February costs. NOB incurred the largest congestion costs in March with a total of about $8.3 million. Total congestion costs for April were about $10.5 million, another substantial decrease from March costs. Path 26 incurred the largest congestion costs in April with a total of nearly $5.4 million. (Note: NOB was offline for the first half of April)

V. Western Regional Market Prices

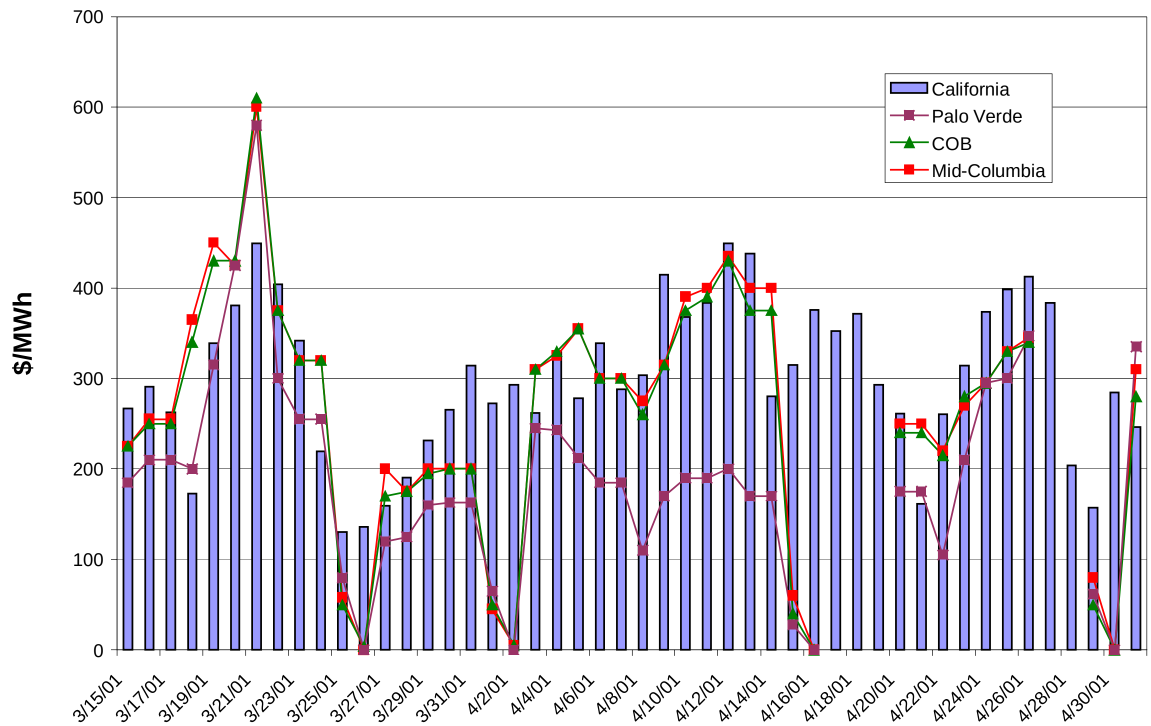
Western Regional Spot Market Prices

Western peak power prices remained high during the mid-March to May period. Prices have remained high due a significant number of generation outages and continued hydro concerns in the northwest and Canada. It is expected that the Columbia River Basin could see its lowest flow volume since 1977 which is likely setting the stage for a very volatile and unprecedented Western energy market for the remainder of 2001.

Prices spiked to near $600/MWh in the western regional markets in the third week of March when California found itself short of power supplies causing two Stage Three power emergencies. A combination of factors led California to the Stage Three emergencies on March 19 and 20 that resulted in rolling blackouts. In California, roughly 12,000 MW of generation was off-line. About 5,000 of the megawatts were down for planned maintenance, and the remaining 7,000 MW for forced outages. An additional 2,000 to 2,900 MW of Qualifying Facilities were non-operational for financial and/or other reasons. Other factors contributing to the shortage and associated regional price increases included the emergence of cooling demand in the Southwest. By the end of that week, returning generation and cooler temperatures in California combined to reduce Western electricity prices from their recent high levels.

Prices started increasing again from the end of March through mid-April as California's tight supply picture was further complicated on April 1 when a severe wind storm toppled six towers along the DC Intertie, curtailing about 3,000 MW of transmission capacity between the Northwest and Southern California. This, in addition to colder than normal weather in California and the Northwest led to the regional price increases. Prices again hit upward pressure in late April as above normal temperatures in the Southwest increased cooling load. Prices dropped significantly throughout the WSCC by the first of May due in large part to rain in the Northwest and cooler than expected temperatures in the coastal Southwest.

Western Firm Peak Prices

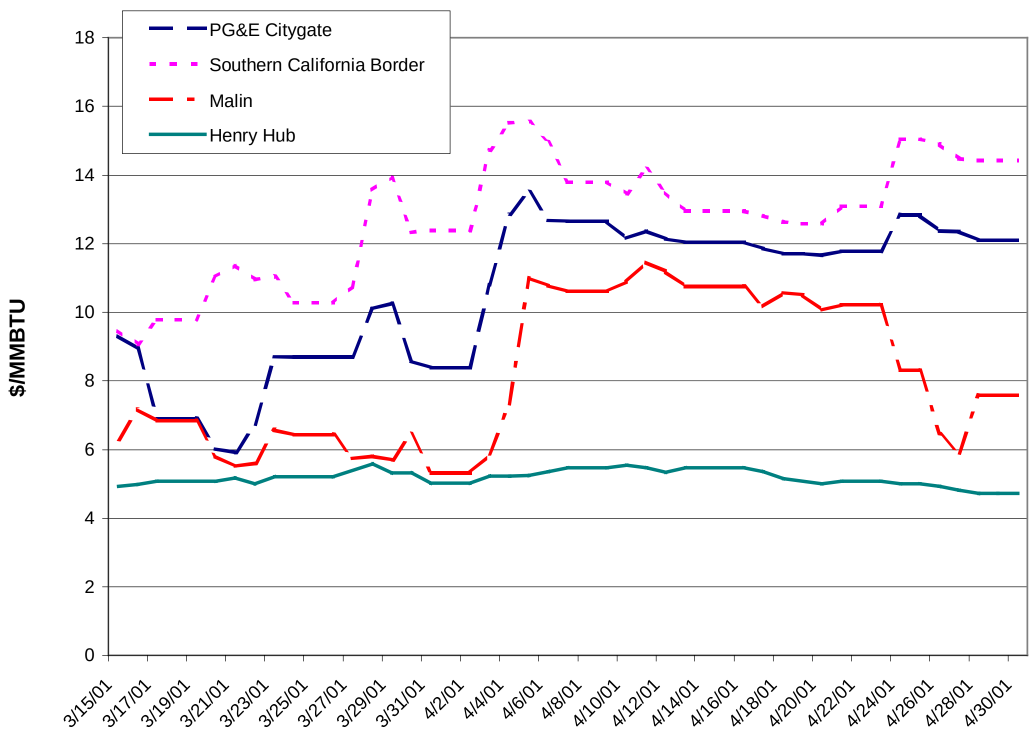


In summary the story remains the same -- tight supply conditions, a low hydro picture in the Pacific Northwest, and uncertainty in the market has led to sustained and highly volatile regional energy prices throughout the WSCC.

Natural Gas Prices

California natural gas markets continued to be volatile during the period mid-March to May with a continued major departures from national Henry Hub market trends, although showing less volatility than in prior periods. By the third week in March there was a large divergence of prices between Malin and PG& E City Gate. Marketers have found the difference hard to explain given that demand levels were not present to support the high PG&E Citygate prices. Beginning in April, prices at the California border again diverged drastically from the national average. Southern California Border prices increased to more than $14/MMBtu in early April while PG&E Citygate prices moved up to the $11/MMBtu range due in part to strong utility buying.

Comparison of Regional Natural Gas Spot Prices

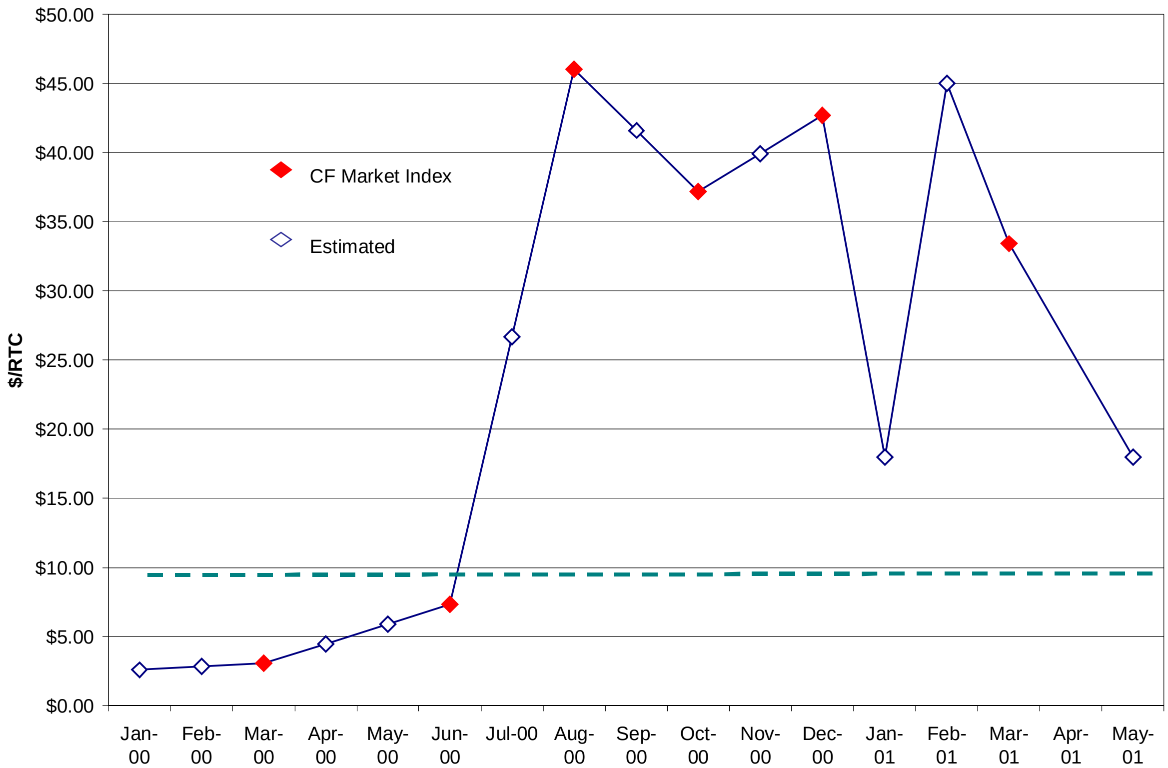


NOx Emissions Prices

NOx emission prices in California continued to fall in anticipation of the South Coast Air Qualify Management District's (SCAQMD) May 11, 2001. At that meeting the District adopted new rules that drastically change the NOx Reclaim market. The new rules[1] separate generators from the Reclaim market and charge generators who use more that their allotment of emission credits $7.50/lb for all NOx emissions in excess of their annual allotment. Although the proposed rules have been in place retroactively through January 11, 2001 through Executive Director Orders, the May 11 Order brings finality to the new rules. The latest available NOx Reclaim Trading Credit (RTC) Market Price Index (MPI) calculated periodically by Cantor Fitzgerald (an average of the best bid, best offer, and most recent trades) was $33.42/RTC as calculated on March 8, 2001. The weighted average price of recent NOx RTC trades calculated on May 4, 2001 was $18/RTC. Due to the new SCAQMD rules adopted on May 11, 2001, generator's RTC prices should be limited to $7.50/lb in the SCAQMD region.

[1] See March 23, 2001 DMA Directors Report for a detailed discussion of the proposed rules.

NOx Emmission Costs



VI. Performance of the Firm Transmission Rights Market in April 2001

FTR Concentration

The FTRs released in the first FTR auction (November 1999) expired on March 31, 2001. The FTRs released in the second FTR auction (January 2001) became effective starting April 1, 2001 (through March 31, 2002).

In addition to the FTRs auctioned in January (reported in the previous Director's Report), the city of Vernon received FTRs on the following paths and directions as a result of having converted their Existing Transmission Rights (ETCs) on these paths.

Branch Group	Direction	FTR MW
NOB	Import (NW3 => SP15)	93
NOB	Export (SP15 => NW3)	82
Mead	Import (LC1 => SP15)	26
Mead	Export (SP15 => LC1)	26
Victorville	Import (LA4 => SP15)	75
Victorville	Export (SP15 => LA4)	75

The assignment date, as registered with the ISO, was April 4, 2001. The effective dates of these FTRs are April 6, 2001 through March 31, 2002. With these assignments the city of Vernon controls the majority of FTRs on NOB in the Export direction. Only 29 MWs were released in the primary auction on this path (with 99.5% annual availability); that is far outweighed by the 82 MWs subsequently assigned to the City of Vernon. Also, the assignment of 75 MW to the City of Vernon on Victorville in the Export direction provides an ownership concentration of 25% on this path for Vernon.

There was only one minor secondary market trade in April, 2001, namely a sale of 25 MW on COI for the period April 27-28, 2001. Apart from the FTRs assigned to the City of Vernon, there was no change in the ownership concentration of FTR owners compared to those reported in the previous Director's 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 April 1-30, 2001 on all paths amounted to only 13% of the total available FTR volume, although on some paths the percentage was rather high (e.g., 96% on Silverpeak and 75% on Eldorado in the Import direction). The following table shows the paths on which FTRs were attached to schedules, along with related statistics for April 2001. Despite concerns about FTR ownership concentration mentioned in the preceding section, as this table shows, there was no noticeable FTR scheduling activity on the paths of concern in April 2001.

FTR Scheduling Statistics in April 2001

Branch Group	ELD IMP	IID-SCE IMP	MEAD IMP	PV IMP	SilvPk IMP	VictVl IMP	COI EXP	MEAD EXP	NOB EXP	PV EXP
MW FTR Auctioned	707	600	461	1,814	10	938	56	430	442	852
Avg. MW FTR Scheduled	533	155	25	529	9.6	9	30	41	2.5	15
% FTR Scheduled	75%	26%	5%	29%	96%	1%	54%	9%	0.6%	2%
Max MW FTR Scheduled	707	167	125	828	10	29	48	171	29	175
Max Single SC FTR Schedule	582	165	75	400	10	7	25	171	25	25

VII. Issues Under Review and Analysis

Monitoring and Reporting of Anti-Competitive Bidding Practices

DMA is developing a variety of special market monitoring indices and reports pursuant the FERC's April 26 Order. The Order requires the ISO to submit weekly reports to the Commission of schedule, outage and bid data to keep the Commission informed on the current market performance, and directs the ISO to identify any concerns about possible inappropriate bidding behavior in the weekly reports. The FERC Order indicates that "the Commission is conditioning public utility sellers market-based rates to ensure that they do not engage in certain anti-competitive bidding behavior," and that "suppliers violating these conditions would have their rates subject to refund as well as [be subject to] the imposition of other conditions on their market-based rate authority." (p.17). The Order identifies two specific types of "anticompetitive bidding behavior": (1) Bid that vary in a way that is unrelated to the known performance characteristics of supply unit or portfolios, such as "hockey stick" bidding patterns where segments of supply is bid at "excessively high levels compared to the remainder of the portfolio, without any apparent performance or input cost basis"; and (2) bids that vary over time in a manner that appears unrelated to changes in supply costs , such as increase in bid prices correlated with increased demand or reduced reserve margins.

Response to FERC Staff Letter Order

DMA performed additional analysis of potential costs in excess of competitive levels in response to a March 31 letter order from FERC staff which requested a response to various questions relating to two reports that accompanied the comments filed by the ISO on March 22, 2001 on FERC Staff's *Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market*. In response to this request from FERC staff, DMA conducted a "bottom up" accounting and analysis of hourly market activity by sellers and determined the degree to which revenues for each transaction in the ISO markets and estimated revenues from energy scheduled with the ISO exceeded the system-level competitive baseline price developed as part of the previous analyses submitted to the Commission. The analysis presented in this report specifically identified the amount of these potential excess payments that may have been incurred each month in the PX and ISO markets, including the monthly amounts attributable to each individual seller and the amount of FERC jurisdictional and non-jurisdictional transactions in each of these markets. The results of this analysis indicates that approximately $4 billion of the $6.7 billion of potential costs in excess of competitive levels identified in this study can be tied directly to specific schedules and transactions in the PX and ISO markets, with the remaining $2.7 billion representing potential bilateral market activity. Actual PX data (including block forward activity) were not available for use in this analysis given the timeframe for a response requested by FERC. Thus, PX market activity had to be estimated based on scheduling data submitted to the ISO (inter-SC trades between the PX and other market participants and imports scheduled with the ISO through PX).

FERC Settlement Agreement with Williams/AES

An investigation of RMR unit outages at the Huntington Beach and Alamitos plants initiated by DMA in May 2000 culminated in an April 30 FERC Order accepting a settlement agreement between FERC staff and Williams/AES. The agreement calls for a refund of $8 million of payments made for out-of-sequence calls to other non-RMR units controlled by Williams/AES to meet local reliability requirements during the RMR unit outages. The case was referred to FERC after DMA's initial investigation indicated that the out-of-sequence payments resulted from potential gaming and abuse of RMR status.

State Senate Investigation of Market Power and Potential Price Manipulation

DMA has responded to a request from a Special State Senate Committee investigating Market Power and Potential price manipulation by providing information and testimony as part of the Committee's initial review of recent market events and previous analyses and investigations. During a special public session on April 17, DMA staff provided testimony and answered questions from the Committee covering material contained in recent FERC filings.

Review of Costs Above Soft Cap Pursuant to FERC Orders

DMA continues to review costs incurred for real time energy above the $150 "soft cap" pursuant to FERC's December 15, 2000 and March 9 Orders. The table below compares sales subject to further review and potential refund based on FERC's proxy price methodology, first outlined in its March 9 Order, which calls for potential refunds for sales over the $150 soft cap only during hours of stage 3 alerts. The very low amount of sales falling within FERC's proxy price methodology in March is attributable to the fact that Stage 3 alerts were declared during only 16 hours during that month. The ISO has filed a request for rehearing of the proxy price methodology outlined in the Commission's March 9 Order, on the grounds that (1) the approach in that order is inconsistent with the December 15 Order that established the "soft cap" market design, along with related guidelines for cost reporting, review and refunds of sales over the $150 soft cap threshold, and (2) it inadequately mitigates unjust and unreasonable market outcomes that previous orders by the Commission have acknowledged are occurring due to current demand and supply conditions in California.

Analysis of Potential Refunds Under FERC Soft Cap
(Millions of Dollars)

		ISO Analysis *		
	FERC Orders Proxy Price/Stage 3	Direct from FERC Jurisdictional Sellers	Other Sellers	Total
January	$69	$132	$170	$ 302
February	$55	$130	$250	$ 380
March	$ .6	$ 44	$312	$ 356
	$125	$306	$732	$1,038

* Estimate of potential charges in excess of just and reasonable levels, based on estimated costs and a benchmark of reasonable profit margin of 10% of operating costs or $25/MW (whichever is lower). For thermal unit within control area, costs estimated based on actual operating levels, heat rates, NOx emission rates, spot market gas and emissions costs. For imports, cost basis estimated based on 12,000 heat rate multiplied by daily spot market gas costs.