California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers

Date: March 23, 2001

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 February 2001.

EXECUTIVE SUMMARY

Despite lower system loads, real time electricity and ancillary service prices remained high in February due to a number of factors including: higher spot natural gas prices, tight supply conditions caused by unit outages, lack of imports, and market power by sellers. There continued to be 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 February increased 25% to $363 from the January average of $290. Pursuant to the conditions placed on purchases made above the $150/MWh soft price cap, in early March the FERC issued refund orders for January and February electricity sales totaling approximately $125 million. No order has been issued regarding purchases in December at prices above the $250/MWh soft price cap.

February was also marked by the closure of the PX Day Ahead market. In January the average volumes in the PX Day Ahead market declined as investor-owned utilities (IOU) shifted to self-scheduling their own generation. The financial uncertainty linked to the IOUs led to a decline in generation offered forward of the real time market and consequently increased the imbalance volume required to clear in the real time market. As a result, the California Department of Water Resources (CDWR) started purchasing electricity on behalf of the IOU customers. February realized an increase in purchases of energy by the CDWR to cover the IOU's "net short" position.

Regional spot electricity markets have seen higher prices in January and February, reaching as high as $500/MWh, as hydro conditions in the Northwest remain at about 50% of normal, natural gas prices remain high, and high electricity prices persist in the California market. The amount of volume transacted at the regional spot prices is unknown making it difficult to make direct comparison to California volume and spot prices. There is concern that low hydro conditions will affect California prices this summer as available imports from the Northwest decline during the summer peak. California border spot natural gas prices increased from $24/MMBTU in January to $30/MMBTU in February due primarily to transportation and storage constraints in the south. Again, it is difficult to determine the volumes transacted at these high spot prices. As milder weather arrives, these prices are expected to moderate this spring. The price for NOx emissions credits declined 22% in February 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 relief to the California electricity market compared with credit prices last summer ranging from $30/RTC to $60/RTC.

Below is a brief summary of market activity.

- **California Loads and Energy Prices**. Total load in February was down 13.7% from January and down 7.3% from last February. However, real time energy prices increased 25% compared with January, from an average of $290/MW to $363/MW.

- **Ancillary service** prices were mixed compared with January. Total ancillary costs were $186 million, down from the January total of $243 million, representing a decrease from $20.31 to $11.27 per MWh of load served.

- **Congestion** in February was primarily limited to south to north congestion on Path 15 and export congestion on NOB. Total congestion costs for February were $20.8 million.

- **Western peak power prices** remained high ($200/MWh to $500/MWh) due to tight supply conditions, a disconcerting water picture in the Pacific Northwest, and uncertainty in the market (particularly over financial matters involving the debt circumstances of PG&E and SCE). Overall, regional prices reported in the Northwest were 55% lower than "effective real time energy prices" in NP15, while regional prices reported in the Southwest were 65% lower than "effective average real time energy prices" in SP15.

- **NOx emission prices** in the South Coast Air Quality District fell on average since December but have been extremely volatile ranging in price from $14/RTC in January to $62/RTC in late February. The Governor's State of Emergency on January 17, 2001, changed the RECLAIM credit costs to generators over 50MW retroactively to January 11, 2001. The changes will result in generators being charged a fixed mitigation fee of $7.50/lb of NOx emissions that are emitted in excess of their current RTC holdings.

- **California spot natural gas markets** continue to be extremely volatile and show major departures from overall market trends. Strong heating and power generation demand combined with stringent balancing requirements on Southern California Gas' system caused spot prices at the burner tip to spike to nearly $40/MMBtu in mid-February. Prices spiked again to more than $29/MMBtu in early March, and have since softened to around $10/MMBtu. It is difficult to estimate the volumes transacted at these high spot prices.

KEY MARKET CONDITIONS FOR FEBRUARY 2001

I. California Wholesale Energy Markets

- **Loads.** February loads decreased from January due to milder temperatures. Monthly system energy loads totaled 16.5 million MWh, a 7.32% decrease from February 2000 and a 13.7% decrease from January 2001. The peak load for the month reached 30,273 MW, a 4.2% increase over February 2000 levels, occurring at HE 19 on February 7. Daily peak loads averaged 28,798 MW, a 5.4% decrease over February 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 California Department of Water Resources purchases on behalf of the UDC's and, during February, comprised between 80 percent and 90 percent of out-of-market purchases. Averages for these different segments of total real time purchases for peak, off-peak, and all hours are reported below:

Table 1 : Energy Price Summary for February 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	$150 (101 GWh)	$434 (572 GWh)	$392 (673 GWh)	$360 (1,308 GWh)	$371 (1,980 GWh)	11,885 GWh 13%
Off-peak	$146 (30 GWh)	$398 (152 GWh)	$357 (182 GWh)	$335 (467 GWh)	$341 (648 GWh)	4,615 GWh 5%
All Hours	$148 (131 GWh)	$427 (724 GWh)	$384 (855 GWh)	$353 (1,774 GWh)	$363 (2,629 GWh)	16,500 GWh 10%

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

- Average real time prices increased in February 25% compared to January. Although total loads in February declined from January, average hourly underscheduling as a percent of load remained steady at 10%. Also contributing to the increase in real time prices was an increase in average spot price for natural gas which was roughly $30 in February compared with $24 in January.

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, a $150/MW soft price cap has been 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. The ISO can minimize the cost of ancillary service purchases by shifting purchases from the day ahead market to the hour ahead market as well as by 'downward' substitution of services where the price differential makes it beneficial to do so (i.e. substituting Spinning Reserve for Non-spinning Reserve where the price of the former is less than the marginal price of the latter). The use of Replacement Reserve for electricity in real time increased late last year, influencing a change in the payment of Replacement Reserve Capacity. Beginning December 31, 2000, capacity payments for Replacement Reserve are refunded to the ISO where the reserves were dispatched in real time. The resulting savings has ranged from $10 million - $20 million per month.

- Average prices for ancillary services increased, on average, compared with January 2001. Although Regulation Up prices decreased by 9% and Regulation Down prices were virtually unchanged, prices for Spinning Reserve, Non-spinning Reserve, and Replacement Reserve increased 38%, 26%, and 10%. Between 62% and 99% of requirements were purchased in the day ahead market. Table 2 below summarizes weighted average prices and quantity procured for February 2001 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 – February 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	$122	$ 101	$ 118	521	52	91%
Regulation Down	$ 48	$ 84	$ 52	640	58	92%
Spin	$ 50	$ 112	$ 57	785	478	62%
Non-Spin	$ 42	$ 78	$ 47	775	125	86%
Replacement	$ 126	$ 120	$ 125	854	4	99%

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

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$ 88	$ 142	$ 143	$ 140	0%
Regulation Down	$ 46	$ 56	$ 47	$ 90	0%
Spin	$ 56	$ 13	$ 72	$ 13	0%
Non-Spin	$ 41	$ 19	$ 109	$ 19	0%
Replacement	$ 134		$ 146		0%

Ancillary Service Costs

- A/S costs in February were $186 million compared to the January total of $243 million. February A/S costs were about 4.6% 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	4.9%
February	**$ 6.650**	**$ 11.27**	**4.6%**

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

III. Out of Market Calls (OOM)

February out-of-market calls remained high largely due to purchases by California Department of Water Resources being recorded as OOM. CDWR purchases accounted for between 80% and 90% of all OOM purchases in February. The average out-of-market costs for February were $382/MWh, up $42/MWh compared with the January average of $340/MWh. On an hourly average basis, 2,638 MW were purchased out of market in February, with 90% of the OOM electricity coming from imports. The total cost of out -of-market purchases in February were $632 million.

Figure 1. Quantities of Out-of-market Purchases
Average Hourly for June 2000 - February 2001

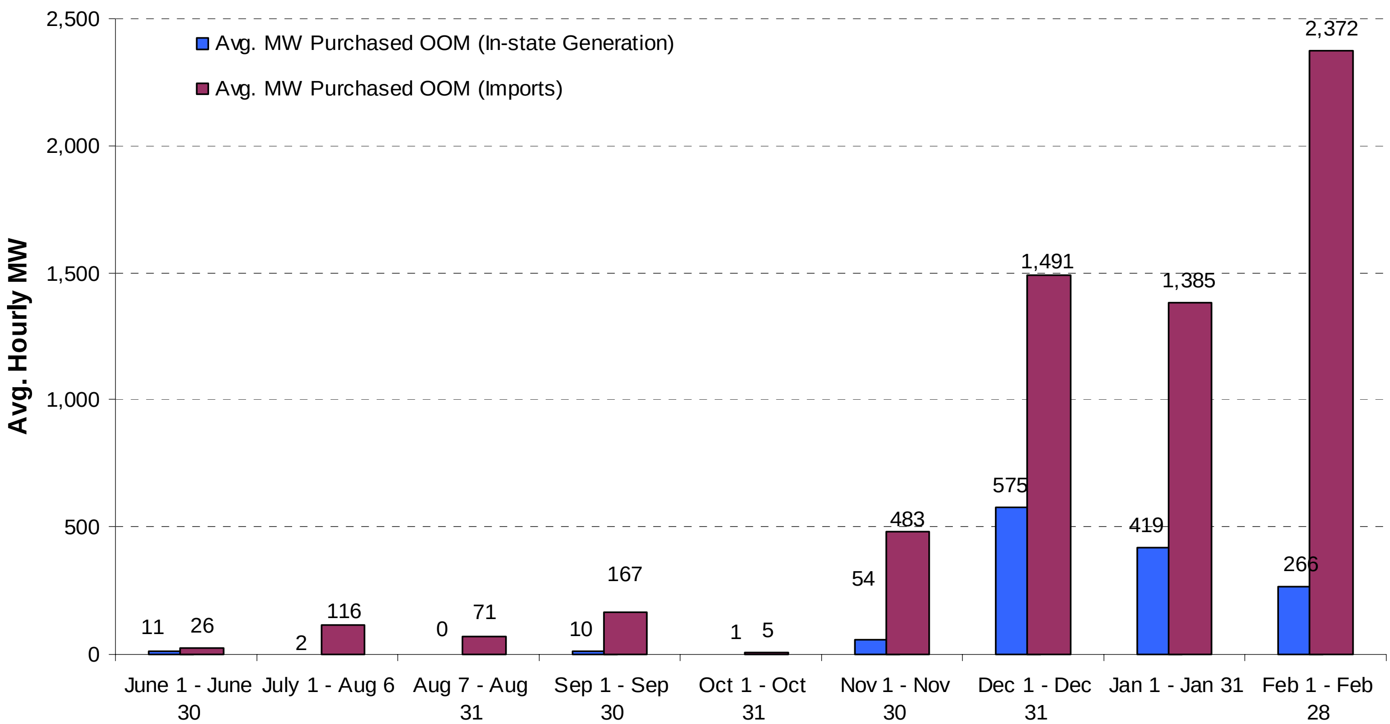


Figure 2. Comparison of Average Costs for Out-of-market and Real Time MCP
June 2000 - February 2001

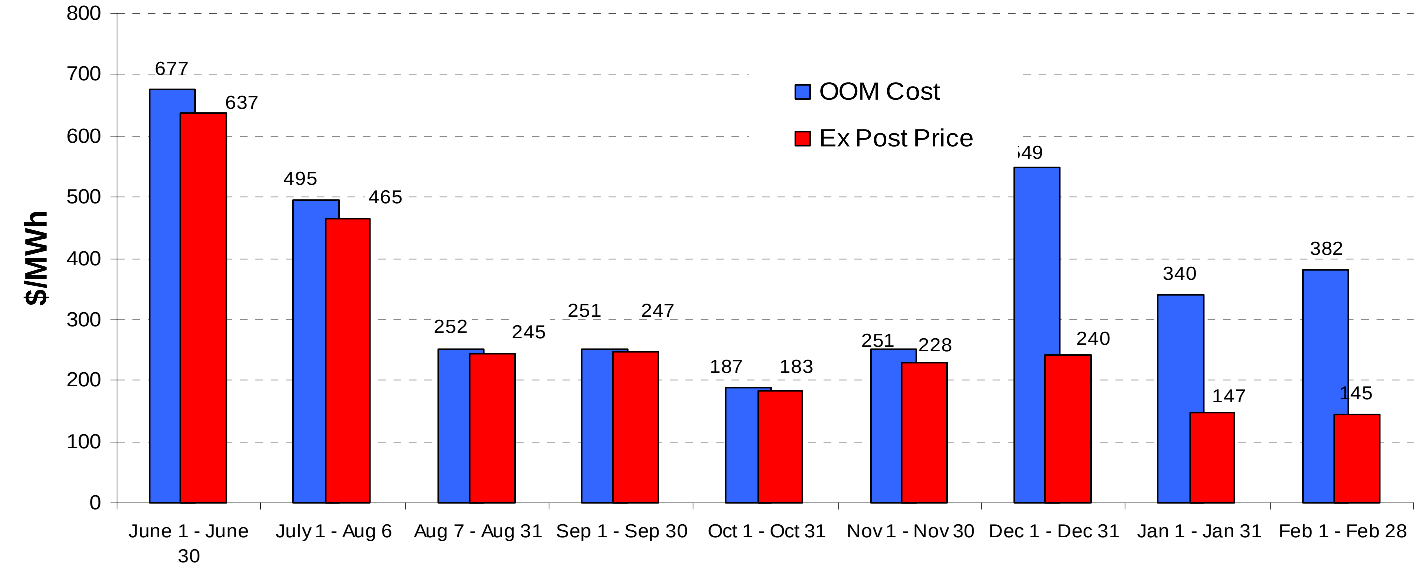
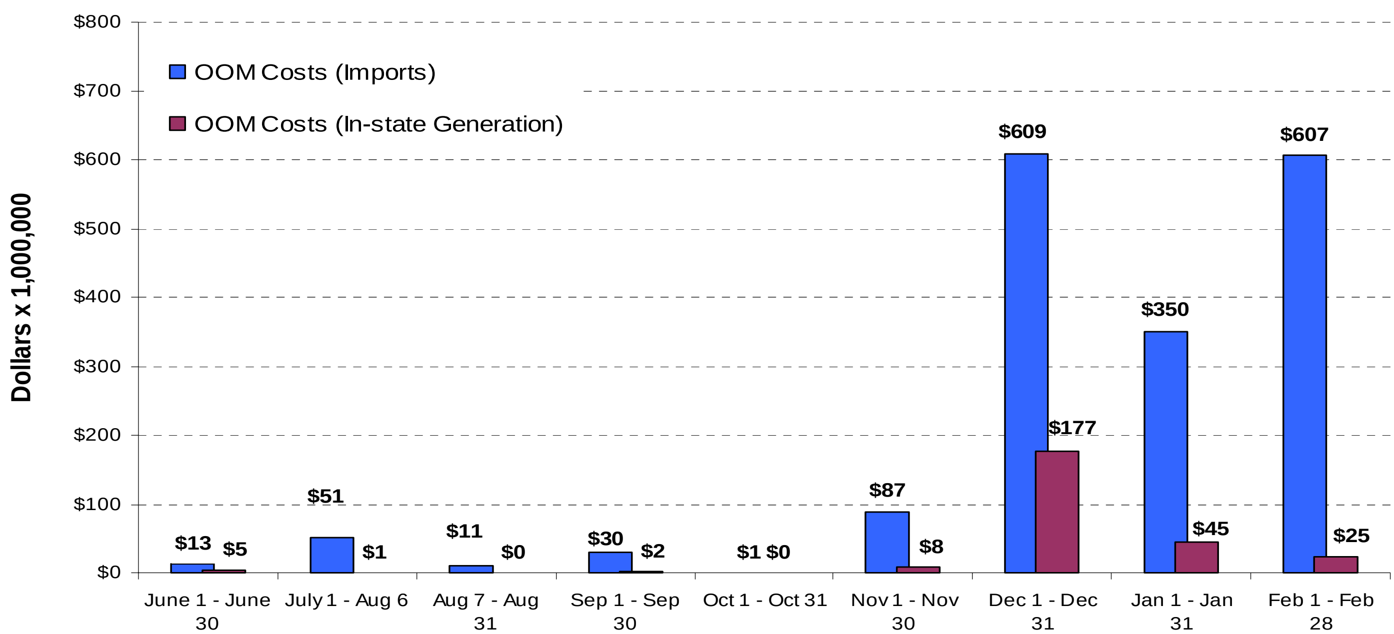


Figure 3.Total Out of Market Costs (in millions of $)



IV. Inter-zonal Congestion Management Markets

Congestion in February 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 January and December. Path 15 experienced reduced congestion in the south to north direction. The following table summarizes congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for February 2001

	Percentage Congestion by Period			**Average Congestion Charges ($/MW)**		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
NOB (Export)	24%	47%	32%	$4.6	$4.42	$4.51
Path 15 (S-N)	46%	42%	45%	$46.92	$49.96	$47.87

- Total congestion costs for February were about $20.8 million, a substantial decrease over the January and December costs. Path 15 and NOB incurred the largest congestion costs with a totals of about $19.7 million and $0.4 million.

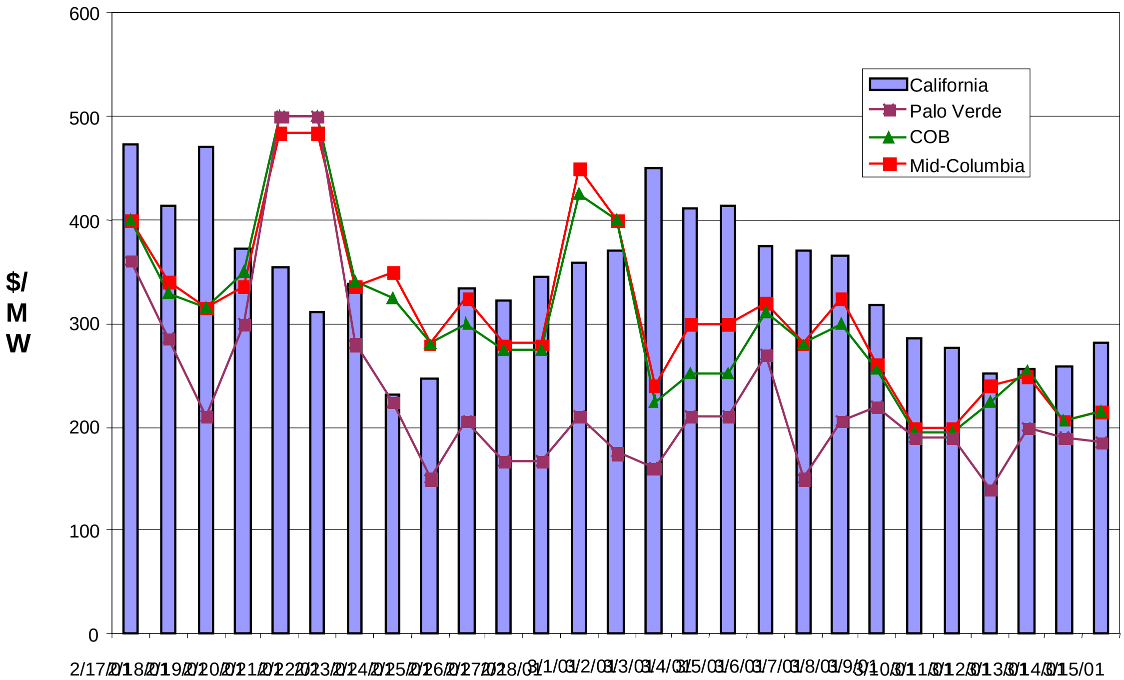
V. Western Regional Market Prices

Western Regional Market Prices

Western peak power prices remained high during the mid-February to mid-March 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. In the Southwest, generation outages continued to strain regional power supplies. Peak spot firm prices in both the North and the South reached as high as $500/MWh on February 22 and 23 due to a forecasted cold snap expected to affect most of the WSCC. The volumes transacted at the regional spot prices is not known and may not be comparable to the volumes in the California markets. Spot prices retreated to $300/MWh and $200/MWh in the Northwest and Southwest respectively by the end of February as milder weather prevailed before Northwestern and California prices again topped the $400/MWh level in early March due to rising spot natural gas prices (see natural gas market update below). As milder weather has spread across the West resulting in lower demand, peak prices in both the Northwest and the Southwest have shown a downward trend to the $200/MWh level by mid-March.

In summary the story remains the same -- tight supply conditions, a disconcerting water picture in the Pacific Northwest, and uncertainty in the market (particularly over financial matters involving the debt circumstances of PG&E and SCE) has led to sustained lofty spot energy prices throughout the WSCC. In comparing regional spot prices it is important to note that large volumes may not be transacting at these high prices.

Western Firm Peak Spot Prices



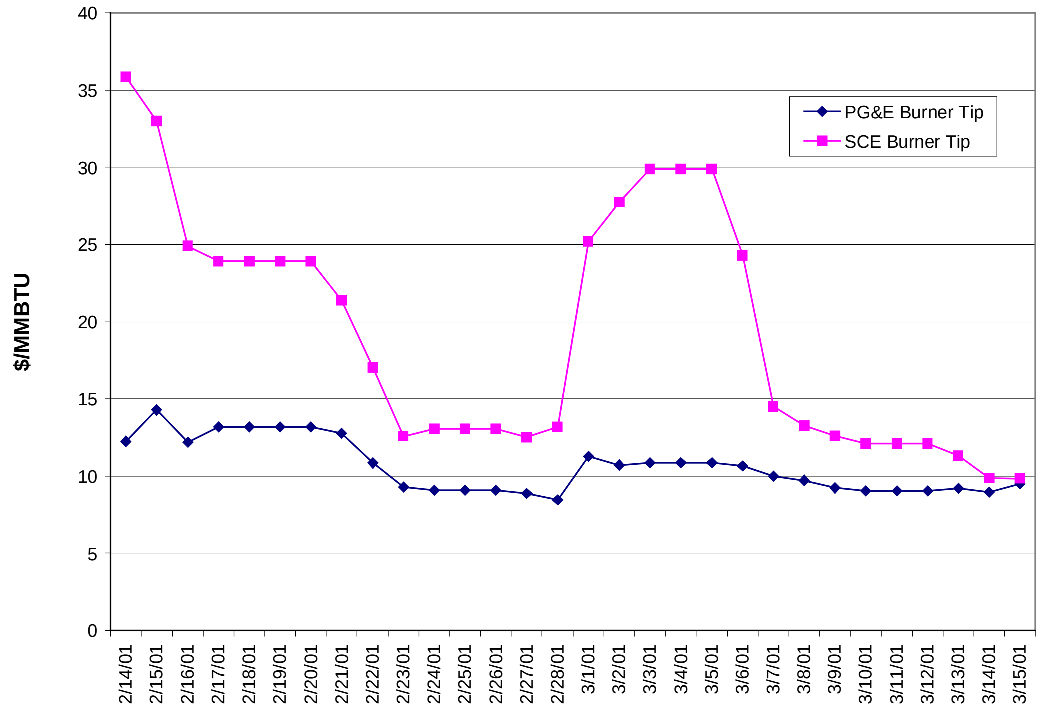
Natural Gas Prices

California spot natural gas markets were extremely volatile during the period mid-February to mid-March and continued to show major departures from overall national market trends. Southern California border spot natural gas prices soared in mid-February to nearly $40/MMBtu. It is important to note that the volumes transacted at these high spot prices is not known. A few factors causing the high spot prices were strong heating and power generation demand and stringent balancing requirements on Southern California Gas' (SoCal) system due to low storage levels. SoCal announced that starting February 15 non-core customers would be required to deliver 90 percent of their daily burn rate or face stiff penalties of 150 percent of the daily reported spot price index. SoCal's storage levels are in a precarious position leaving the utility with limited flexibility in balancing its pipeline. PG&E Citygate prices did not react similarly to the Southern California Border price spikes due to long standing capacity constraints (to Topock) which causes gas to get trapped in PG&E's system. Therefore, these gas supplies are unable to reach the Southern California Border markets to mitigate the price spikes.

By February 15, spot prices at the Southern California border fell back to $20/MMBtu as the winter storm that entered the State earlier in the week moved eastward and the initial shock of SoCalGas' 90 percent balancing requirement seemed to subside.

Southern California Border prices dropped significantly to the $12/MMBtu range in late February as demand decreased due to milder weather. However, California natural gas prices soared again in early March largely due to expectations of a large portion of El Paso supply getting taken off the market. The El Paso Pipeline had planned to take Keystone Station in the Permian Basin out of service for maintenance starting March 2 reducing capacity by 400 MMcf/d. Due to a low-linepack, El Paso postponed the work until the weekend, however, the postponement announcement occurred too late to affect the Southern California Border spot prices. California border prices continued to climb to an average of more than $29/MMBtu due to speculations regarding continuing field capacity restrictions, high demand as another storm hit the area, a new Stage One Electrical Emergency issued by the ISO, and concerns of SoCal Gas storage running low.

California Natural Gas Spot Prices



By mid-March, Southern California Border prices softened considerably back to around $10/MMBtu as demand continued to drop and it became known that SoCal Gas' 90 percent daily balancing rule will be lifted at the end of the month. Non-core customers will return to 90 percent monthly balancing on April 1 which is normal for this time of year. SoCal Gas has also recently started posting net injections into storage. Given these conditions, prices are expected to stabilize.

El Paso Natural Pipeline Capacity Auction

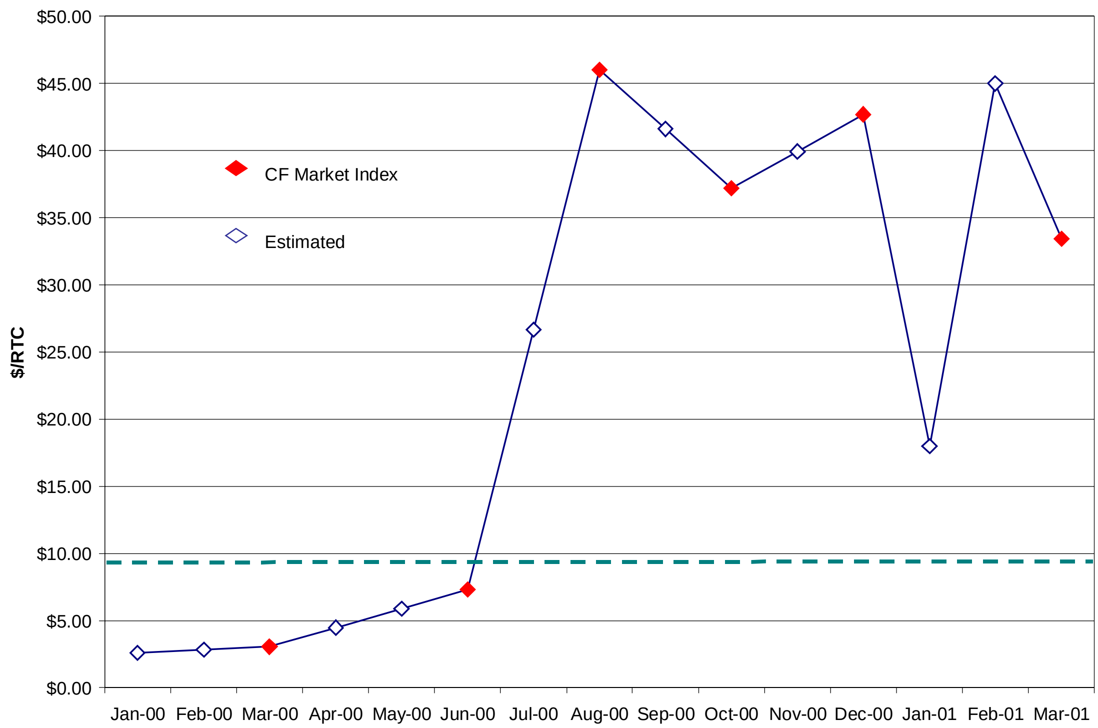
In El Paso's latest capacity auction held in mid-February, affiliates of El Paso Energy, Enron, Duke Energy and PG&E picked up the largest shares of the 1.2 Bcf/d of available space on El Paso Natural Gas lines to Southern California points. Although the posted bids may not reflect the final allocation, it does not appear that the current holder of the capacity, El Paso Merchant Energy, whose contract runs out May 31, will exercise its right of first refusal. The bids posted totaled 1,243,072 MMBtu/d and the major purchasers were: El Paso Merchant Energy with 276,932, Enron Energy Services 254,056, Duke Energy affiliates 211,697, PG&E affiliates 151,300, Texaco Natural Gas 58,407, and Dynegy affiliates 56,418. Although the bid prices have not been disclosed, it is expected that the winning bidders were all close to the FERC price cap for firm transportation service.

El Paso's open season for the 1.2 Bcf/D of firm transportation attracted bids for 14.4 Bcf/d of capacity. Due to this overwhelming response for the capacity, El Paso has announced an open season to test market interest in a mainline expansion and to satisfy regulatory concerns that something needs to be done to relieve the apparent capacity constraint at the California border. El Paso has been under significant pressure from regulators and shippers to expand because of enormous demand and extremely high prices in California. The open season will end March 23.

NOx Emissions Prices

A series of recent events have changed the RECLAIM market retroactively to January 11, 2001. First, pursuant to an SCAQMD White Paper on Stabilization of NOx RTC prices, the District issued a proposed

NOx Emmission Costs



rule that would bifurcate the RECLAIM market between electric generators and non-utility facilities. Generators would be charged a mitigation fee of $7.50/lb of NOx emissions that are emitted in excess of their current RTC holdings. Although the rule is not expected to be adopted by the SCAQMD until May 11, 2001, a Governor's Executive Order (#01-03) issued on February 20, 2001 places the provisions of the proposed rule in affect retroactive to January 11, 2001. Therefore, generator NOx emission costs in SCAQMD are no greater than $7.50/lb and the remaining RTC market prices will be determined by non-utility facilities.

NOx emission prices in California have fallen on average since December, yet have also been extremely volatile as vintage 2000 credits traded for $14/RTC in January and $62/RTC in late February. The March 8, 2001 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) fell by 22 percent ($33.42/RTC), giving back much of the increase that occurred in December 2000. The change is a reversal from the December 2000 MPI in which the MPI rose between 10% and 104% for all vintages. The decline can be attributed, in part, to actions taken by the South Coast Air Qualify Management District (SCAQMD). Reacting to prices that exceeded the $15,000/ton backstop threshold by six times, the SCAQMD sent to proposed rulemaking a variety of program adjustments (see below). These proposals, combined with the SCAQMD's open invitation for sources to enter into settlement agreements and abatement orders, initially resulted in prices plunging from $43/RTC (traded 1/3/01) to $14/RTC (traded 1/20/01). Seeing a buying opportunity and recognizing that the existing program rules are still in force, a number of buyers bought vintage 2000 NOx RTCs causing prices to increase. Prices increased past $20/RTC on 1/25/01, then past $30/RTC on 2/2/01, past $45/RTC on 2/2/01, before finally peaking out at $62/RTC on 2/26/01. As the reconciliation period for the fourth quarter of 2000 drew to a close, vintage 2000 RTC prices fell back to $30/RTC on 2/27/01 and finally to $18/RTC by March 1.

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

FTR Concentration

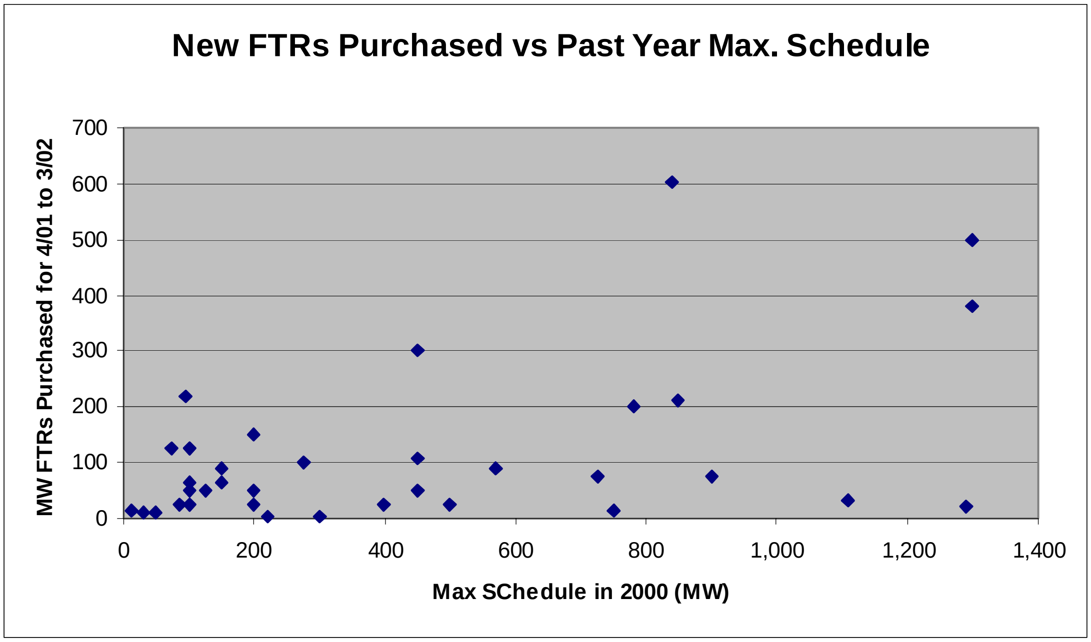
The FTRs released in the first FTR auction (November 1999) expire on March 31, 2001. There were no ownership changes for these FTRs in February 2001. There were minor scheduling coordinator reassignments for FTRs on Eldorado, NOB, and Palo Verde with no significant impact on SC control concentration.

The FTRs released in the second FTR auction (January 2001) have an effective date beginning April 1, 2001 through March 31, 2002. There were no secondary market trades on these new FTRs. Only 176 MW of the new FTRs (on Palo Verde) were assigned Scheduling Coordinators in February 2001. The following Table summarizes the ownership concentration on various paths in descending order for entities owning more than 25% share of the FTRs on the path.

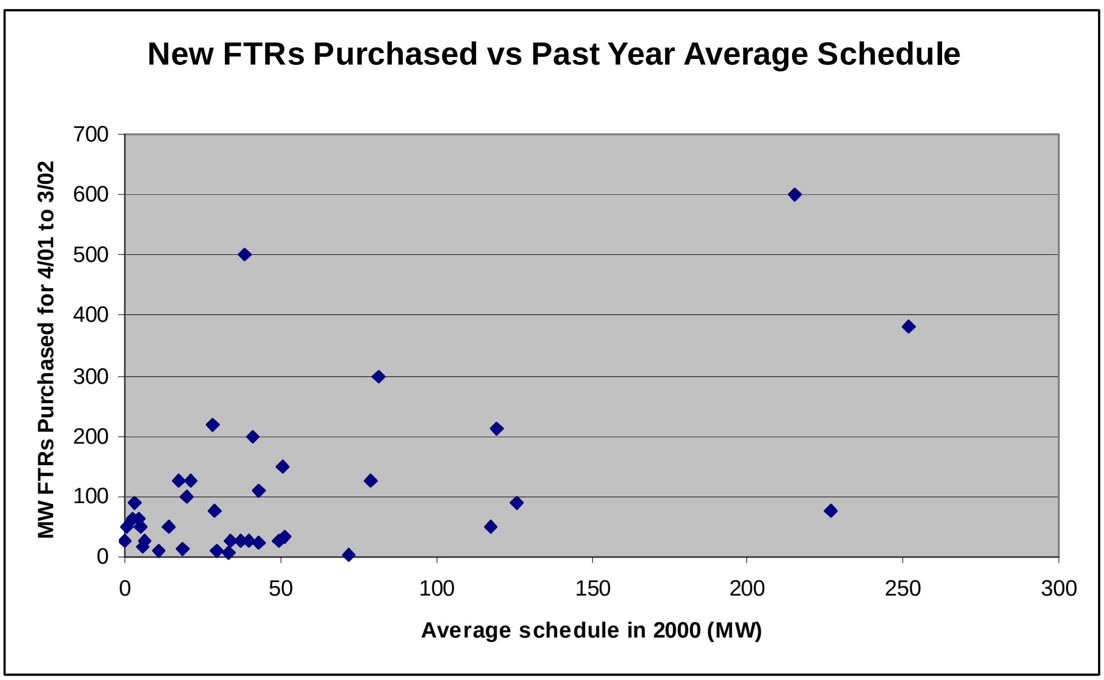
Branch Group	FTR Auction Winner	Total MW	Awarded MW	% Ownership
Silver Peak_BG (SP15-SR3)	Idaho Power Company	10	10	100%
Silver Peak_BG (SR3-SP15)	Southern California Edison Co	10	10	100%
NOB_BG (SP15-NW3)	Southern Company Energy Marketing	29	25	86%
Eldorado_BG (AZ2-SP15)	Southern California Edison Company	707	582	82%
IID-SCE_BG (II1-SP15)	Southern California Edison Company	600	460	77%
Victorville_BG (SP15-LA4)	Idaho Power Company	221	166	75%
Eldorado_BG (SP15-AZ2)	Idaho Power Company	626	401	64%
COI_BG (NP15-NW1)	Southern Company Energy Marketing	56	33	59%
NOB_BG (NW3-SP15)	Southern California Edison Company	430	250	58%
Path 26_BG (SP15-ZP26)	Southern Company Energy Marketing	199	100	50%
Mead_BG (SP15-LC1)	Idaho Power Company	430	213	50%
CFE_BG (SP15-MX)	PG&E National Energy Group	408	200	49%
Palo Verde_BG (SP15-AZ3)	Williams Marketing and Trading	796	381	48%
CFE_BG (MX-SP15)	Morgan Stanley Capital Group	408	171	42%
COI_BG (NP15-NW1)	Idaho Power Company	56	23	41%
Path 26_BG (SP15-ZP26)	New Energy Inc.	199	74	37%
COI_BG (NW1-NP15)	Idaho Power Company	600	219	37%
Victorville_BG (LA4-SP15)	Morgan Stanley Capital Group	938	316	34%
Victorville_BG (LA4-SP15)	Southern Company Energy Marketing	938	314	33%
Path 26_BG (ZP26-SP15)	Southern California Edison Company	1,727	575	33%
Palo Verde_BG (AZ3-SP15)	Southern California Edison Company	1,819	602	33%
Mead_BG (SP15-LC1)	Southern Company Energy Marketing	430	125	29%
Path 26_BG (ZP26-SP15)	PG&E National Energy Group	1,727	500	29%
Path 26_BG (ZP26-SP15)	Southern Company Energy Marketing	1,727	477	28%
Palo Verde_BG (AZ3-SP15)	Williams Marketing and Trading	1,819	500	27%
Mead_BG (LC1-SP15)	Southern Company Energy Marketing	461	125	27%
CFE_BG (SP15-MX)	Idaho Power Company	408	106	26%
Palo Verde_BG (SP15-AZ3)	Idaho Power Company	796	200	25%
CFE_BG (SP15-MX)	Morgan Stanley Capital Group	408	102	25%
CFE_BG (MX-SP15)	PG&E National Energy Group	408	100	25%

The following graph is a scatter diagram showing the FTRs purchased in the new FTR auction (April 2001 through March 2002) versus maximum hourly scheduled energy on the same path by the same owner/SC in the year 2000.

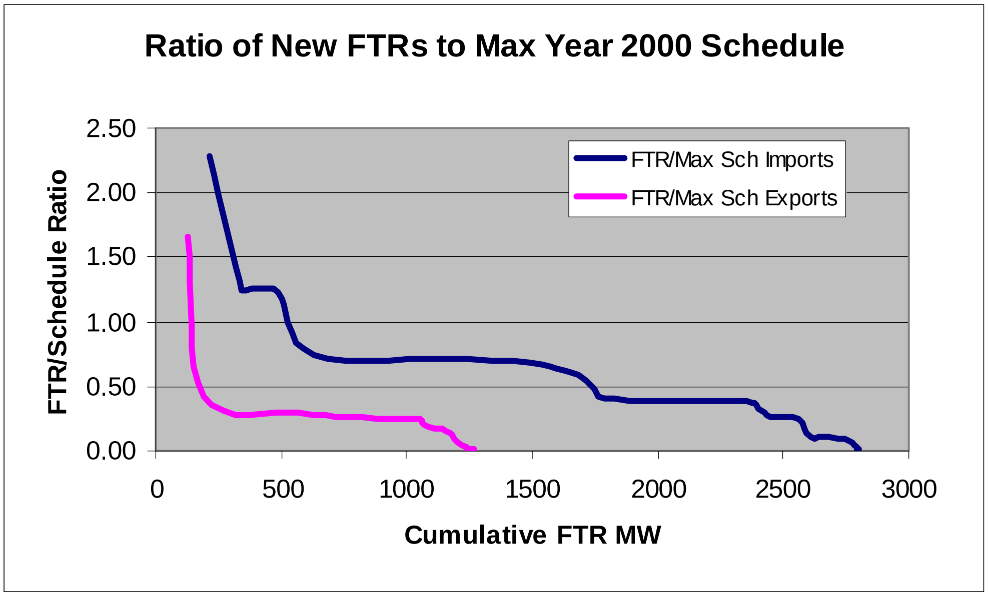
The following graph shows the same type of scatter diagram with respect to average hourly scheduled energy on



the same path by the same owner/SC in the year 2000.



These diagrams show little correlation between FTRs purchased going forward and the preceding year schedules of the same entities. The following graph shows the ratio of the new FTRs purchased to the year 2000 maximum hourly schedules of the same entities on the same paths, separately for import and export paths.



This diagram shows that some entities acquired FTR MWs more than their maximum MW schedule in any hour in the year 2000. Starting April 1, 2001 (the effective start date of these FTRs), the scheduling patterns of these FTR holders will be monitored to better understand their intention of acquiring high FTR volumes.

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 February 1-28, 2001 on all paths amounted to only 16% of the total available FTR volume. The following table shows the paths on which FTRs were attached to schedules, along with related statistics for February 2001.

Branch Group	ELD IMP	IID-SCE IMP	MEAD IMP	PV IMP	SilvPk IMP	MEAD EXP	NOB EXP	PV EXP
MW FTR Auctioned	707	600	461	1,814	10	430	442	852
Avg. MW FTR Scheduled	409	447	4	657	9	62	42	4
% FTR Scheduled	58%	71%	1%	36%	90%	15%	9%	1%
Max MW FTR Scheduled	460	447	18	1,031	9	200	50	100
Max Single SC FTR Schedule	410	444	16	600	9	200	50	50

VII. Issues Under Review and Analysis

1. **Market Stabilization Plan.** The DMA is actively collaborating with other ISO departments to develop a Market Stabilization Plan for implementation before summer 2001. The plan incorporates a simplified version of the Market Power Mitigation plan developed by DMA, taking into account the concerns and comments expressed by the ISO's Board of Governors, and subsequent discussions with EOB and CDWR. The plan also includes important short-term modifications in the operation of the ISO markets in view of the demise of Cal PX.

   The main elements of the Market Stabilization Plan are explained elsewhere in the Board material, and will not be repeated here. The main simplification in the Market Power Mitigation Plan is the elimination of a supplier-specific link between the level of forward contracting and mitigation of the supplier (unit-specific bid caps would include fuel and NOx adjusted variable cost plus 10% regardless of the level of forward contracting; start-up and no-load costs to be paid separately as uplift if the unit is committed because of ISO instruction and is unable to recover such cost through market revenues). Another important short-term simplification is to allow for RMR-type fixed option payment contracts (between ISO/CDWR and the suppliers) instead of imposing Available Capacity Reserve (ACR) obligations on the load serving entities.

   The Market Stabilization Plan has been discussed with the Board on March 15, 2001 and the ISO will be seeking Board approval of this plan on March 30, 2001.

2. **Analysis of Bids Above the Soft Cap.** The DMA continues to work toward the goal of ensuring that the FERC's review and refund authority for all bids over the "soft caps" that have been in place since December 8, 2000 is exercised in a way that results in just and reasonable rates. On March 1, the ISO and EOB filed a motion with FERC requesting that the Commission (1) open a hearing to review the information compiled by DMA concerning bids above the "soft caps" after December 8, 2000 and to determine the amount of refunds due, if any, (2) notify all sellers that sales over soft cap are under review, thereby extending the 60-day period for such notification established in the December 15 order, and (3) provide the ISO and EOB with cost data supplied to the Commission for sales over the soft cap. On March 9, the Commission issued an order notifying non-public sellers approximately $69 million of transactions in the ISO and PX markets over a $273 price during hours of Stage 3 emergencies in January may be subject to refund, and that sellers should provide further data in support of these sales. The $273 threshold for January was based on the Commissions estimates of the operating cost of a "proxy" peaking unit given average spot market gas prices and estimated NOx emission costs in January. On March 16, the Commission issued a second order covering the month of February, identifying another $55 million in transactions over a $430 threshold price during stage 3 emergencies are subject to the same refund and cost justification requirements. The $430 threshold for February was based on the same formula used in the March 9 order, updated with the commission's estimates of average spot market gas prices and estimated NOx emission costs in February. There is a 30-day period for filing for rehearing of these orders. As of the date this memo was prepared, the ISO is assessing options for filing for rehearing of these orders. None of the above mentioned FERC orders addressed the December period or other issues raised in the ISO's March 1 filing.

3. Market Power Impacts.

An update of the monthly estimate of market power impacts of wholesale energy prices (including historical Power Exchange prices and ISO Real-time market costs are provided in the Figure below.

Analysis of Impact of Market Power on Wholesale Energy Prices