CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Board Assistants; ISO Officers

Date: June 15, 2001

Re: Market Analysis Report for May 2001

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

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

EXECUTIVE SUMMARY

Real time electricity and ancillary service prices decreased in May compared to April due to increased hydro flows in the Northwest and lower natural gas prices. However, prices remained high due to a number of factors including: continued higher than normal spot natural gas prices, tight supply conditions caused by increased cooling demand, generation outages, and exercise of market power by sellers. In addition, many QFs remain off-line due to continued financial uncertainty surrounding payments from utilities. On average, the price of real time electricity in May decreased 26% to $275/MWh from the April average of $370/MWh. Although loads increased in May compared to April as warmer temperatures increased cooling demand, loads declined from May 2000 levels showing visible conservation efforts. Total load in May was down 1.7% from May of last year. When normalizing for weather conditions, the California Energy Commission estimate savings from conservation resulted in an 11% reduction in energy usage and a 10 percent reduction in peak demand on a weather normalized basis.[1]

The California Energy Resources Scheduling division of the California Department of Water Resources (CERS) purchases the net short portion of the California investor-owned utility loads. In May, the forward energy purchases by CERS limited the underscheduling of loads to an average of 7.1 percent in May.

Regional spot electricity prices decreased significantly in May from April, however, prices continued to be high due to a number of factors. While increased hydro flows in May from spring runoff and lower natural gas prices put downward pressure on prices, prices remained high due to low hydro storage levels in the Northwest, tight supply conditions caused by planned and unplanned outages for Western region resources, and continued higher than normal natural gas prices. Overall, regional prices reported in the Northwest were 0.7% lower than “effective real time energy prices” in NP15, while regional prices reported in the Southwest were 3% lower than “effective 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.

[1] See June 4, 2001 Governor Gray Davis Press Release.

California average spot natural gas prices decreased from $13/MMBtu in April to $9/MMBtu in May due to warmer weather conditions leading to less heating demand combined with increased hydro generation reducing demand for gas fueled generation.[2] NOx emission costs also decreased significantly in May. Recent actions taken by the South Coast Air Quality Management District (SCAQMD) effectively removed generators located within the SCAQMD region from the emissions trading market (RECLAIM). These actions result in NOx emission costs of no greater than $7.50/lb for generators located within the region once they have exhausted their annual allocation of free credits. Therefore, the current SCAQMD NOx emission credit market prices no longer have any relation to emission costs incurred by generators. The new SCAQMD rules are similar to the emission limitation rules in effect in other air management districts in the state.

Other key market activities include the following:

- **Lower Ancillary Service Costs.** In May, ancillary service prices decreased compared to April and total costs decreased by 9%. Total ancillary service costs were $162 million in May, down from the April total of $178 million, representing a decrease from $10.33 to $8.23 per MWh of load served.

- **Higher Congestion Costs.** Congestion in May was primarily limited to Path 26 in the south to north direction, exports to the Northwest on COI and NOB, and imports from Palo Verde. Total congestion costs for May were approximately $7.0 million, down from $10.5 million in April.

[2] California average natural gas prices are the average of PG&E Citygate and Southern California Border prices. It is difficult to determine the volume traded at these prices.

KEY MARKET CONDITIONS FOR MAY 2001

I. California Wholesale Energy Markets

- **Loads.** The results of conservation efforts by California consumers were seen in lower monthly system energy loads for May totaling 19,651 GWh, a 1.7% decrease from May 2000. The peak load for the month reached 37,633 MW, a 4.8% decrease from the May 2000 of 39,521 MW. Daily peak loads averaged 26,412 MW, a 1.7% decrease from May 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 cost justified as determined by FERC. 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 (1), the as-bid price and volume for bids accepted over the price cap (2), and the Out-of-market purchases in real-time (4). The combination of these components yields the total "effective real time price" (5). OOM costs include CERS purchases on behalf of the IOU's in real-time (4). The averages for each of these different segments of total real time purchases for peak, off-peak, and all hours are reported below in the columns specified by ( ):

Table 1: Real Time Energy Price Summary for May 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)	Average System Loads and Percent Under-scheduling
Peak	$83.21 (26 GWh)	$391.50 (16 GWh)	$113.20 (43 GWh)	$311.59 (1,320 GWh)	$289.51 (1,363 GWh)	28,747 MW 8.6%
Off-peak	$43.55 (-12 GWh)	$248.81 (13 GWh)	$80.35 (1 GWh)	$258.27 (518 GWh)	$237.93 (518 GWh)	21,742 MW 3.2%
All Hours	$72.34 (14 GWh)	$329.64 (29 GWh)	$103.56 (43 GWh)	$296.27 (1,837 GWh)	$274.66 (1,881 GWh)	26,412 MW 7.1%

* The values in this table represent the average prices of all transactions and should not be used to value total transactions which occur at separate INC and DEC prices.

Note: Dollar figures are $/MWh and % represents percent underscheduling. The above dollar values are the average prices per MWh transacted in real-time and do not represent the average cost of electricity. For reference, the average cost of electricity for the entire system (including UDC generation at cost, bilateral transactions at hub prices, and real time costs) for the month of May was $164/MWh.

- Average real time prices decreased 26% in May compared to April. Total loads in May increased from April as did average hourly underscheduling which increased as a percent of load from 6% to 7.1%. Contributing to the monthly price differences in real time prices was a decrease in the average spot price for natural gas from $12.85/MMBtu in April to $9.23/MMBtu in May.[3]

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. Beginning December 31, 2000, capacity payments for Replacement Reserve are refunded 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 May, on average, compared with April 2001. Regulation Up prices increased by 15% while Regulation Down prices increased by 2%. Prices for Spinning Reserve increased by 4% while prices for Non-Spinning Reserve fell 26%. Replacement Reserve prices decreased by 6%. Between 76% and 100% of requirements were purchased in the day-ahead market. Table 2 below summarizes the weighted average prices and quantity procured for May 2001 in both the day-ahead and hour-ahead markets.

- Table 3 compares 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 May 2001.

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – May 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	$ 123	$131	$ 125	243	78	76%
Regulation Down	$ 58	$ 53	$ 57	581	156	79%
Spin	$ 83	$ 42	$ 80	757	57	93%
Non-Spin	$ 54	$ 20	$ 52	704	65	92%
Replacement	$ 122	$ 17	$ 114	479	-41	109%

[3] Average spot price for natural gas is equal to the average of PG&E Citygate and Southern California Border prices.

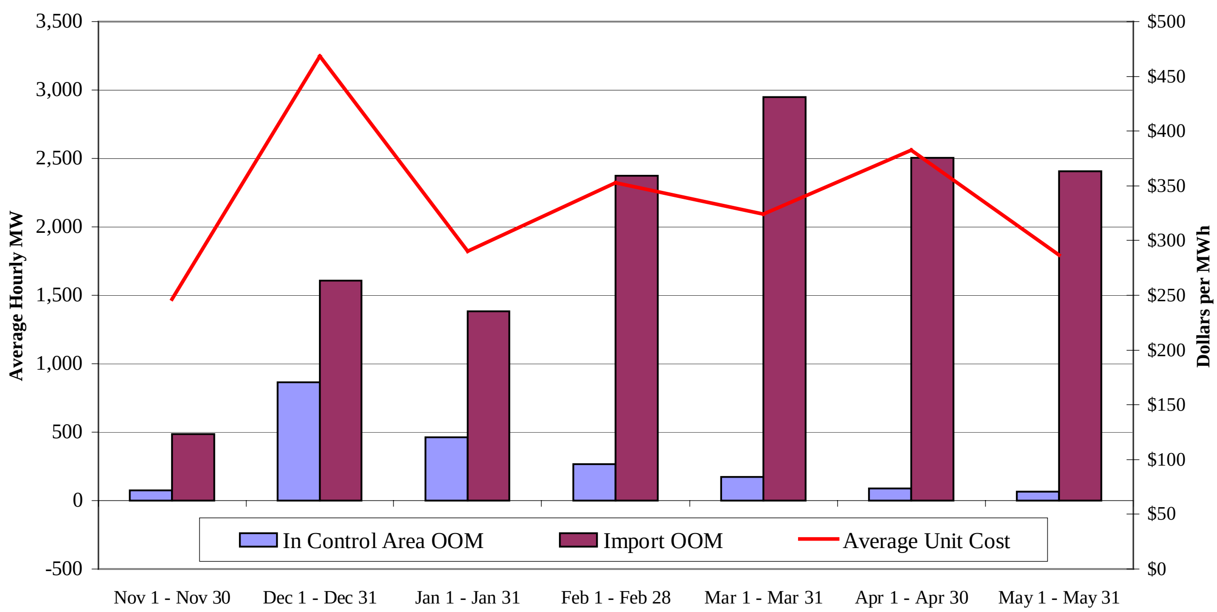
Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – May 2001

	NP15		SP15		Percent of Hours with
	Peak	Off Peak	Peak	Off Peak	Zonal Procurement
Regulation Up	$ 87	$ 118	$ 139	$ 145	0%
Regulation Down	$ 30	$ 97	$ 47	$ 111	0%
Spin	$ 102	$ 40	$ 90	$ 41	0%
Non-Spin	$ 71	$ 11	$ 72	$ 13	0%
Replacement	$ 118	$ 38	$ 80	$ 32	0%

III. Out of Market Calls (OOM)

May out-of-market calls remained high largely due to purchases by CERS in real-time being recorded as OOM. The average out-of-market costs for May were $287/MWh, down $95/MWh compared with the April average of $382/MWh. On an hourly average basis, 2,470 MW were purchased out of market in May, with 97% of the OOM electricity coming from imports in each month. The total cost of out -of-market purchases in May was $527 million.

Figure 1. Quantities of Out-of-market Purchases (Average Hourly)
September 2000 - May 2001



IV. Summary of Market Costs

The total cost of energy and ancillary services in May was approximately $3.49 billion, increasing from $3.47 billion in April. The average cost of energy and A/S decreased from $201/MWh in April to $178/MWh in May. Energy and A/S costs continue to be significantly higher than those seen in the first two years of operation. Total energy and A/S costs for the first nine months of ISO operation in 1998 were approximately $5.55 billion resulting in an average cost of $33/MWh. Total costs in 1999 were comparable to 1998 with a total cost of approximately $7.03 billion and an average cost of energy and A/S remaining steady at $33/MWh. Costs increased substantially in 2000. Total costs for energy and A/S in 2000 were over $27 billion resulting in an average cost of $114/MWh. In 2001, through May, total energy and A/S costs are more than $18 billion with an average cost of $203/MWh of load served. First quarter costs in 2001 have increased significantly over the first quarter costs of 2000 increasing to over $11.3 billion from approximately $1.7 billion in 2000. The following table provides a summary of Energy and A/S costs.

Summary of Energy and Ancillary Services Costs

Cost Summary through December 2000:

	ISO Load (GWh)	Est PX Energy Costs (MM$)*	Bilateral Energy Costs (MM$)*	RT Energy Costs (MM$)**	AS Costs (MM$)***	Total Energy Costs (MM$)	Costs of AS+ Energy (MM$)	Avg Energy Cost ($/MWh)	A/S Cost ($/MWh Load)	A/S Costs as % of Energy Costs	Total Costs ($/MWh load)
1998 (9mo)	169,239	$ 4,148	$ 556	$ 209	$ 638	$ 4,913	**$ 5,551**				
Avg 1998	18,804	$ 461	$ 62	$ 23	$ 71	$ 546	$ 617	$ 29	$ 3.77	13.0%	$ 33
Total 1999	227,533	$ 5,866	$ 982	$ 180	$ 404	$ 7,028	**$ 7,432**				
Avg 1999	18,961	$ 489	$ 82	$ 15	$ 34	$ 586	$ 619	$ 31	$ 1.78	5.7%	$ 33
Jan-00	18,984	$ 495	$ 103	$ 3	$ 12	$ 601	$ 612	$ 32	$ 0.62	2.0%	$ 32
Feb-00	17,807	$ 419	$ 103	$ 20	$ 10	$ 542	$ 552	$ 30	$ 0.58	1.9%	$ 31
Mar-00	18,989	$ 432	$ 90	$ 39	$ 11	$ 561	$ 572	$ 30	$ 0.60	2.0%	$ 30
Apr-00	18,212	$ 429	$ 101	$ 31	$ 17	$ 561	$ 578	$ 31	$ 0.95	3.1%	$ 32
May-00	19,997	$ 828	$ 225	$ 108	$ 63	$ 1,161	$ 1,224	$ 58	$ 3.16	5.4%	$ 61
Jun-00	21,605	$ 2,303	$ 529	$ 339	$ 436	$ 3,171	$ 3,607	$ 147	$20.19	13.8%	$ 167
Jul-00	21,935	$ 1,896	$ 346	$ 216	$ 125	$ 2,458	$ 2,583	$ 112	$ 5.71	5.1%	$ 118
Aug-00	23,141	$ 2,786	$ 585	$ 515	$ 282	$ 3,886	$ 4,168	$ 168	$12.18	7.3%	$ 180
Sep-00	20,620	$ 1,819	$ 389	$ 236	$ 152	$ 2,445	$ 2,597	$ 119	$ 7.39	6.2%	$ 126
Oct-00	18,184	$ 1,400	$ 356	$ 27	$ 56	$ 1,388	$ 1,434	$ 100	$ 3.33	3.3%	$ 104
Nov-00	18,656	$ 2,292	$ 402	$ 195	$ 114	$ 2,889	$ 3,004	$ 155	$ 6.13	4.0%	$ 161
Dec-00	19,412	$ 3,742	$ 820	$ 1,149	$ 440	$ 5,711	$ 6,151	$ 294	$22.65	7.7%	$ 317
Total 2000	237,543	$ 18,842	$ 4,048	$ 2,877	$ 1,720	$25,373	**$27,083**				
Avg 2000	19,795	$ 1,570	$ 337	$ 240	$ 143	$ 2,114	$ 2,257	$ 107	$ 7.24	6.8%	$ 114

* Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.
Estimated Bilateral Energy Cost based on the difference between hour ahead schedules and PX quantities,valued at PX prices.
** Beginning November 2000, ISO Real Time Energy Costs include OOM Costs.
*** AS costs include self-provided quantities.

Cost Summary Since January 2001:

	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs (MM$)***	A/S Costs (MM$)****	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
Jan-01	18,770	16,950	$ 2,710	$ 761	$ 246	$ 3,472	$ 3,718	$ 177	$13.12	7.1%	$ 198
Feb-01	16,503	14,876	$ 2,657	$ 955	$ 196	$ 3,612	$ 3,808	$ 206	$11.87	5.4%	$ 231
Mar-01	17,857	16,744	$ 2,736	$ 856	$ 179	$ 3,591	$ 3,771	$ 186	$10.04	5.0%	$ 211
Apr-01	17,237	16,267	$ 2,537	$ 749	$ 178	$ 3,286	$ 3,465	$ 181	$10.33	5.4%	$ 201
May-01	19,651	18,351	$ 2,771	$ 558	$ 162	$ 3,329	$ 3,490	$ 164	$ 8.23	4.9%	$ 178
Total 2001	90,018	83,188	$13,411	$ 3,879	$ 962	$17,290	**$18,252**				
Avg 2001	18,004	16,638	$ 2,682	$ 776	$ 192	$ 3,458	$ 3,650	$ 183	$10.68	5.6%	$ 203

***** Sum of hour-ahead scheduled quantities
****** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices
******* includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid
******** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

IV. Inter-zonal Congestion Management Markets

Congestion in May mainly occurred on Path 26 in the south to north direction with occasional congestion on imports from Palo Verde and exports on NOB and COI. Congestion on Path 26 increased considerably compared to April in the south to north direction while NOB and COI export congestion decreased significantly in May compared to April. Total congestion costs for May decreased to approximately $7.0 million from $10.5 million in April. Path 26 congestion accounted for $4.5 million of the total congestion costs in May. Export congestion costs on NOB decreased from $8.3 million in April to approximately $0.27 million in May.

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

Day-Ahead Market – Congestion Summary for May 2001

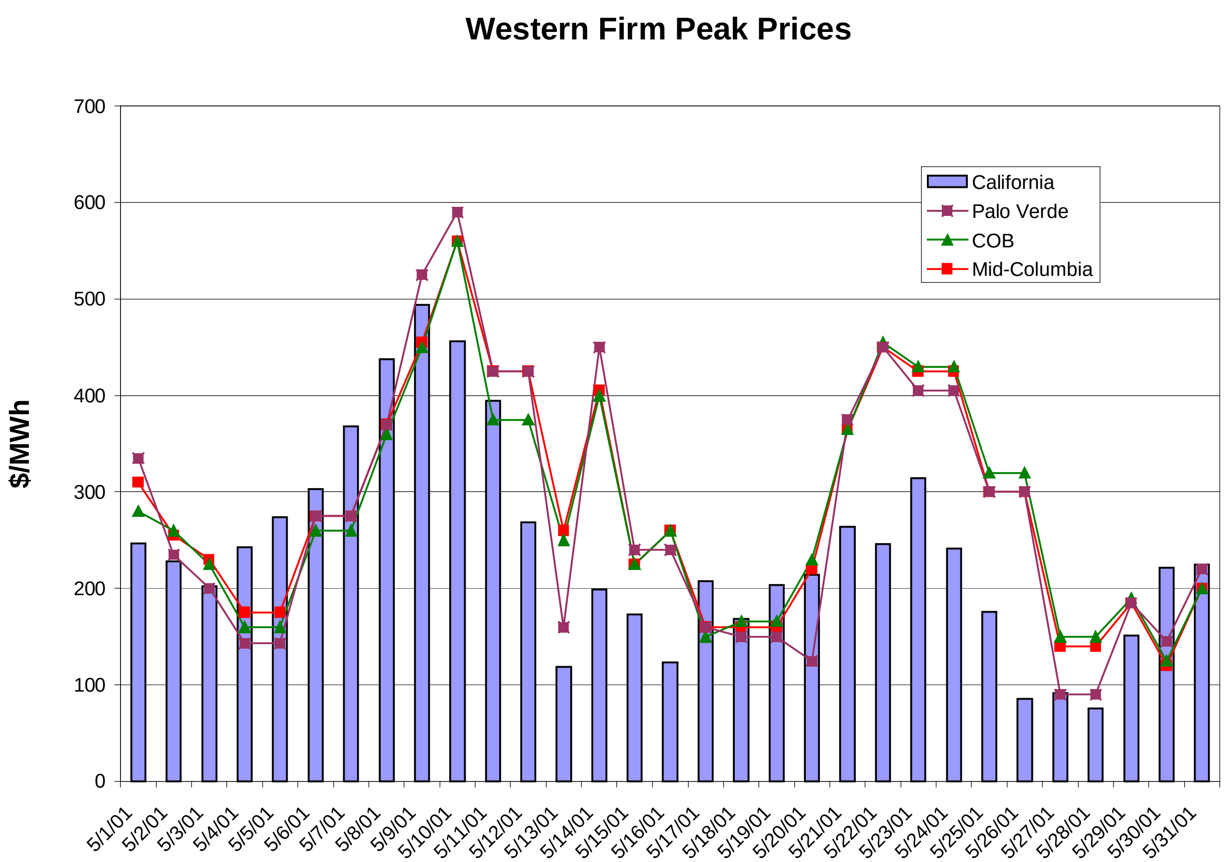
	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Export)	1%	7%	3%	$1	$11	$9
NOB (Export)	17%	46%	26%	$11	$29	$21
Palo Verde (Import)	0%	7%	2.4%	$0	$36	$36
Path 26 (S-N)	3%	37%	14%	$130	$47	$56

V. Western Regional Market Prices

Western Regional Spot Market Power Prices

Western peak power prices remained generally high and volatile during May. Prices have remained high due to a significant number of generation outages and continued hydro concerns in the Northwest and Canada. As previously reported, it is expected that the Columbia River Basin could see its lowest flow volume since 1977 which will likely result in volatile high prices in the Western energy markets for the remainder of 2001.

Western power prices fell sharply in early May due to generation returning online and moderate weather. However, spring power prices have not decreased as much as they have in recent years from spring runoff hydro flows as a portion of these higher flows are instead being used to refill reservoirs that were depleted over the winter. By the second week of May prices rose sharply due to a heat wave in the Southwest and California. Palo Verde prices climbed to near $600/MWh. On May 7th and 8th the ISO declared Stage 3 power emergencies as a result of high demand causing prices to rise above $400/MWh throughout the West. However, power prices fell throughout the West during mid-May as cooler temperatures reduced weather-related demand. Returning generation and increased hydro generation also helped to reduce prices. The most significant price declines occurred in the Pacific Northwest where heavy rains and increased spring runoff increased the power production of run-of-the river dams. Prices increased again in the third week of May as temperatures increased in the Northwest, Southwest, and parts of California combined with a refueling outage of a nuclear unit in Washington. Finally, Western power prices decreased at the end of the month due to milder weather conditions and the holiday weekend, which significantly reduced demand throughout the Western region. These market conditions caused prices to fall to less than $200/MWh.

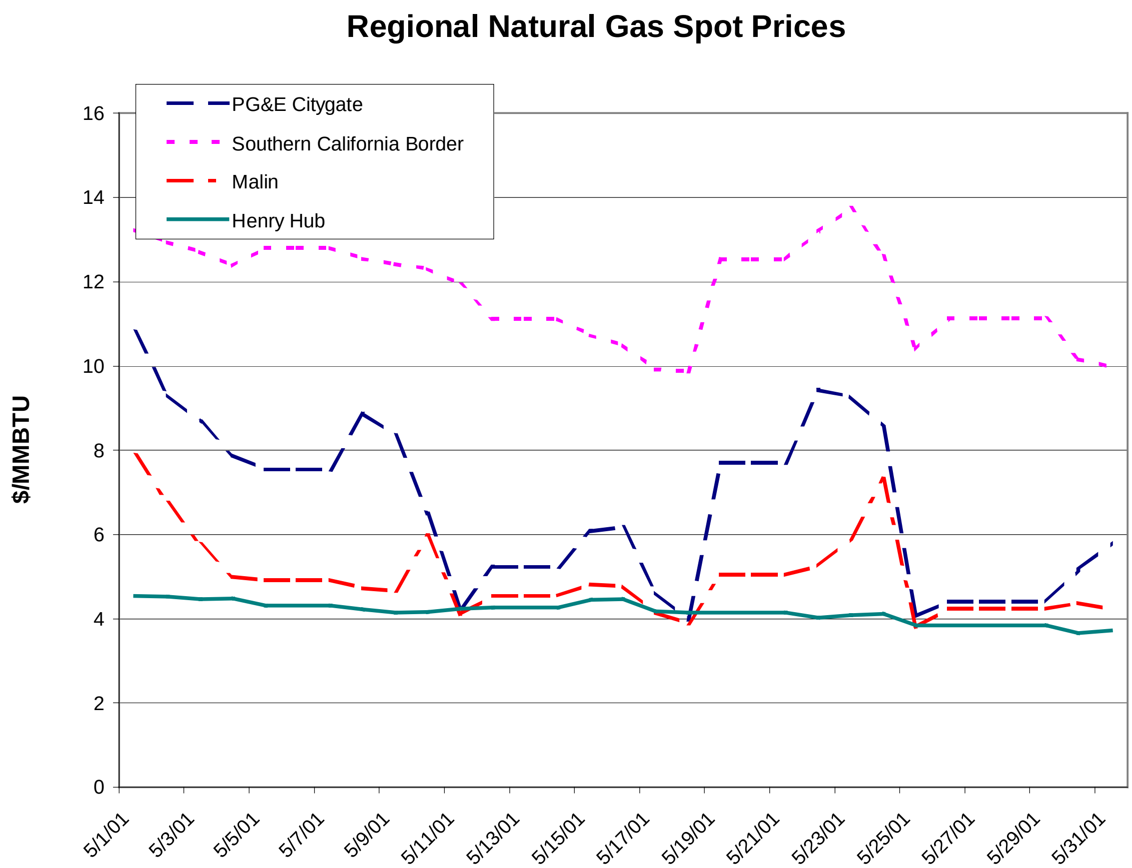


California Natural Gas Prices

California natural gas spot prices declined significantly in May compared to April, particularly in northern California at PG&E Citygate and Malin trading points. Both northern and southern California delivery prices responded to mild weather conditions in early May. In addition, PG&E, which until recently had its linepack (pipeline storage) volumes in the vicinity of its minimum target level, predicted that its linepack would rise above its maximum target level over the next few days. California prices continued to decrease in early May, particularly at PG&E Citygate and Malin, which saw decreases of $6/MMbtu and $4/MMbtu respectively. The price decreases were due to mild temperatures in Northern California, which again caused PG&E's linepack to reach critical levels. A system wide high-linepack Operational Flow Order (OFO) [4] with zero tolerance for positive imbalances reduced PG&E Citygate prices to near $4/mmbtu on May 19. PG&E Citygate prices have not been at that level since July 2000. However, prices increased to near $14/mmbtu at the Southern California Border and to near $10/mmbtu at the PG&E Citygate by May 24 due to increased power generation load as temperatures increased in California and Arizona. The large increase in gas demand reduced PG&E's linepack, which had been at maximum levels, to near minimum levels. However, at the end of May temperatures moderated causing PG&E to again declare a high

[4] An Operational Flow Order (OFO) is a mechanism to protect the operational integrity of the pipeline. For example, PG&E may issue and implement system-wide, local or customer specific OFOs in the event of high or low pipeline inventory. The order requires shippers to take action to balance their supply with their customers' usage on a daily basis within a specified tolerance band.

linepack Operational Flow Order resulting in prices near $4.50/mmbtu at PG&E Citygate and Malin and $10/mmbtu at Southern California Border.



NOx Emissions Prices

On May 11, the South Coast Air Quality Management District (SCAQMD) Governing Board voted to accept a proposed comprehensive RECLAIM rule amendment package. The new rules include the following amendments to the current rules:

- Generators greater than 50MW are bifurcated from the existing RECLAIM universe. These generators must install controls by 2004 and may only trade RTCs as follows:
  - Generators may sell RTCs in excess of what they were originally allocated for that particular vintage to the private market, as long as they do not utilize the Mitigation Fee ($7.50/lb in excess of their allocation) for that particular vintage.
  - Generators may sell any excess RTCs to the SCAQMD. The SCAQMD is not guaranteeing that they will pay $7.50/lb.
  - Generators may not buy RTCs from any entity other than the SCAQMD (through the mitigation fee program).
  - Generators may be let back in the market in 2005 if determined to be net sellers by the SCAQMD.

The new rules ensure that generators located within the SCAQMD region will have NOx emission costs of no greater than $7.50/lb of emission once they have used their allocation of free credits. The current SCAQMD NOx emission credit market prices no longer have any bearing on emission costs to generators. The new SCAQMD rules are similar to the emission limitation rules in affect in other air management districts in the state.

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

FTR Concentration

There were no secondary FTR market trades in May 2001. Therefore, there was no change in the ownership concentration of FTR owners compared to those reported in the April Market Analysis 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 May 1-31, 2001 on all paths amounted to only 17% of the total available FTR volume, although on some paths the percentage was rather high (e.g., 95% on Silverpeak and 87% on Eldorado in the Import direction). The following table shows the paths on which FTRs were attached to schedules, along with related statistics for May 2001. Only those paths on which FTRs were attached to at least 5% of the schedules are shown. Despite concerns about FTR ownership concentration on NOB (export direction) and Victorville (export direction) discussed in the previous Director's Report, there was no noticeable FTR scheduling activity on NOB, and moderate FTR scheduling activity on Victorville in May 2001.

FTR Scheduling Statistics in May 2001

Branch Group	COI IMP	ELD IMP	IID-SCE IMP	MEAD IMP	PV IMP	SilvPk IMP	COI EXP	MEAD EXP	PV EXP	P26 EXP	VictVl EXP
MW FTR Auctioned	600	707	600	487	1,819	10	56	456	796	1,727	296
Avg. MW FTR Scheduled	40	614	128	24	587	9.5	6	50	141	125	31
% FTR Scheduled	7%	87%	21%	5%	32%	95%	11%	11%	18%	7.3%	11%
Max MW FTR Scheduled	301	707	159	175	1,080	10	25	128	475	625	109
Max Single SC FTR Schedule	101	582	159	125	600	10	25	128	381		109

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 confidential 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 reports.

FERC Real Time Price Mitigation Plan

DMA is assessing data from the first two days in which the real time price mitigation plan outlined in the April 26 Order was in effect (May 30-31, 2001). Results indicate that one of major factors that will determine the effectiveness of the price mitigation plan will be the degree to which FERC orders refunds from in-state generators that submitted bids in excess of the cost-based mitigated price used to dispatched units and determine the MCP.

Investigation of Market Power and Potential Price Manipulation

DMA continues to collaborate with a variety of state and federal agencies conducting confidential investigations of potential market power abuses and price manipulation.

Investigation into Increased Exports for January 2001 - May 2001

Average hourly gross exports increased over 90% for the period January 2001 through May 2001 compared with the same period in 2000 while average hourly net imports declined by only 25%. This disparity can be explained by three different factors.

First, in December 2000 the ISO began exchanging electricity with outside traders to make up for supply shortages during peak periods. These exchanges added volume to both gross imports and gross exports. In addition, to circumvent transmission constraints on Path 15, the ISO began sending electricity north on the DC line from SP15 to the Northwest, and south to NP15 via COI. This practice also added volume to both gross imports and gross exports. For the period December 2000 through May 2001, exchanges and re-circulation combined contributed from 150 to 950MW to hourly average gross imports and 100 to 600 MW to hourly average gross exports.

In addition, the Pacific Northwest was coming off of a t low hydro year and historically high provision of electricity to California during the summer of 2000. The hydro recharge season started slow and finally yielded only approximately 55% of historical hydro storage for the region. This resulted in a change in trade pattern with the Pacific Northwest where imports from the region were down 15% on average and exports to the region were up 485% on average, leading to a 50% decrease in average net imports from the Northwest.

Finally, some of the increase in gross exports and the change in trading pattern with the Pacific Northwest may be attributable to either practices employed to circumvent price cap restrictions or trading practices employed to provide electricity to the state to meet net short load. DMA is continuing to look into both of these issues.