CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Governing Board

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers

Date: February 16, 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 January 2001.

JANUARY HIGHLIGHTS

Tight supply conditions, a disconcerting water picture in California and the Pacific Northwest, suppliers' uncertainty in the market over financial matters involving the debt circumstances of California's two biggest utilities, have meant a sustained level of high energy costs throughout the WSCC.

- California Energy prices were slightly lower and more stable in January compared with December, due in part to the lower gas prices. Natural gas prices declined to an average of $12/MMBTU in January compared with the December average of approximately $26/MMBTU. Prices stabilized as well, with minimum and maximum prices of $10/MMBTU and $15/MMBTU compared with $12/MMBTU and $60/MMBTU in December Despite the improvement in natural gas prices, low hydro conditions in the West, persistent generation unit outages, UDC credit deficiencies, and reduced PX volumes generated real-time system shortages with little available energy bids in the BEEP stack to meet system need for real-time imbalances.

- January monthly peak load for the ISO control area reached 32,450 MW, down 2.5% from January 2000, while total energy increased by 1.1% from the previous year. Average daily peaks were 30,017 MW, a decrease from 31,270 MW in December due in part to the extensive conservation efforts during Stage 3 emergencies.

- The estimated total energy and A/S cost for January was $5.2 billion, or about $278/MWh of load served, compared to about $6.3 billion ($326 per MWh of load served) in December. Although average costs declined from December levels, they remain consistently high compared to the soft price cap of $150 implemented at the beginning of the month.

- The average constrained PX price for the month was $281/MWh, up 815% from $30.72/MWh in January 1999 and up 6% from the $266/MWh average in December. Additional energy needed was procured through the (1) real-time market at prices under the soft cap averaging $148/MWH, (2) real-time as-bid payments at prices of $359/MW, and (3)out of market calls by the ISO and DWR at prices averaging $294/MWh. The effective real time prices (total of the three pricing mechanisms) averaged $290/MWh (down from December average of $423/MW).

- ➢ January prices (weighted by volume purchased) in the ancillary service markets decreased moderately compared to December. Regulation up, regulation down, spinning reserve, and non-spinning reserve prices all decreased from 31% to 62% compared with December. Replacement reserve prices increased by 7%.

- ➢ Ancillary service costs decreased to $12.96/MWh of load compared to the December value of $22.65/MWh and the January 2000 value of $0.62/MWh. Total A/S costs were about $243 million in January 2001, which is about 4.9% of total wholesale energy costs, compared to the December rate of 7.5%.

- ➢ Congestion decreased in January with Import congestion from the Southwest disappearing and export congestion to the Northwest declining considerably.

KEY MARKET CONDITIONS FOR JANUARY 2000

I. <u>California Wholesale Energy Markets</u>

- **Loads.** January loads decreased from December due to colder temperatures. Monthly system energy loads totaled 18.770 GWh, a 1.1% decrease from January 2000. The peak load for the month reached 32,450 MW, a 0.7% decrease over January 2000 levels, occurring at HE 18 on January 10. Daily peak loads averaged 30,072 MW, a 2.5% decrease over January 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 implementation of the soft cap increased participation in the real time energy market and decreased reliance on out of market purchases. The as-bid structure and continued reliance on out-of-market purchases has created several prices and volumes that can be reported in 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 then added to this to comprise the total effective cost of real time price. 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 January 2001

	Market Clearing Avg. Price and Total Volume (1)	As-bid Avg. Price and Total Volume (2)	Total BEEP* Avg. Price and Total Volume	Out-of-market Avg. Price and Total Volume (3)	Effective Real Time Avg. Price and Total Volume (4)
Peak	$150 (282 GW)	$376 (692 GW)	$311 (974 GW)	$298 (997 GW)	$304 (19,722 GW)
Off-peak	$146 (154 GW)	$273 (142 GW)	$207 (296 GW)	$282 (345 GW)	$248 (641 GW)
All Hours	$148 (436 GW)	$359 (834 GW)	$287 (1,270 GW)	$294 (1,342 GW)	$290 (2,613 GW)

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

- Market clearing energy prices for the PX and ISO Real time market under $150 by zone and period are listed in Table I. Note that the statistics reported for Real Time Price are simple averages and are only for the market clearing price at or below the (soft) price cap. They do not reflect the prices for out-of market purchases. System average prices were summarized at the beginning of this section.

Table 2: Energy Price Summary for January 2001 in PX Market and ISO Real-time

(ISO MCP under $150 Only)

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
ISO Real Time Price					
Peak	$146.41	$148.47	$144.35	$144.35	11%
Off-Peak	$131.51	$141.47	$121.55	$121.55	33%
Total	$141.44	$146.13	$136.75	$136.75	18%
PX Constrained					
Peak	$291.76	$310.80	$272.72	$272.72	58%
Off-Peak	$259.74	$284.23	$235.74	$235.24	46%
Total	$281.08	$301.94	$260.23	$260.23	54%

Significant real time congestion persisted on Path 15 in the S-N direction, occurring during 54% of all hours.

II. Ancillary Service Markets

Ancillary Service Prices

- During January Regulation Up prices hit the price cap 96 hours in the day ahead markets and 196 hours in the hour ahead markets, Regulation Down prices hit the price cap 39 hours in the day ahead markets and 96 hours in the hour ahead markets, Spinning Reserve prices hit the price cap 30 hours in the day ahead markets and 42 hours in the hour ahead markets, Non-spinning Reserve prices hit the price cap 4 hours in the day ahead markets and 52 hours in the hour ahead markets, and Replacement Reserve prices hit the price cap 78 hours in the day ahead markets and 53 hours in the hour ahead markets.

- The ISO procured most of its A/S requirements in the day-ahead market, with between 65% and 91% of A/S MW quantities being procured in the day-ahead market. Table 2 below summarizes weighted average prices and quantity procurements for January 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 3. Summary of Weighted Day-Ahead A/S Prices by Market – January 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	$110	$ 117	$111	509	120	81%
Regulation Down	$ 82	$ 93	$ 83	624	62	91%
Spin	$ 78	$ 98	$ 81	719	301	70%
Non-Spin	$ 56	$ 89	$ 62	719	190	79%
Replacement	$ 111	$ 106	$ 109	742	394	65%

Table 4. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – January 2001

	NP15		SP15		Percent of Hours with Zonal Procurement
	Peak	Off Peak	Peak	Off Peak	
Regulation Up	$ 85	$ 110	$ 49	$ 132	1%
Regulation Down	$ 63	$ 116	$ 95	$ 127	0%
Spin	$ 76	$ 40	$ 89	$ 80	0%
Non-Spin	$ 44	$ 34	$ 105	$ 76	0%
Replacement	$ 121		$ 117		3%

Ancillary Service Costs

- A/S costs in January were $243 million compared to the December total of $439 million. January A/S costs were about 4.9% of total energy costs. Day ahead A/S prices in January were considerably lower than December, due in large part to a lower price cap effective the beginning of the month. Compared with December, regulation up prices decreasing by 29%, regulation down decreasing by 30%, spinning reserve decreasing by 46%, non-spinning reserve decreased by 61%, and replacement reserve decreasing by 12%.

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%**

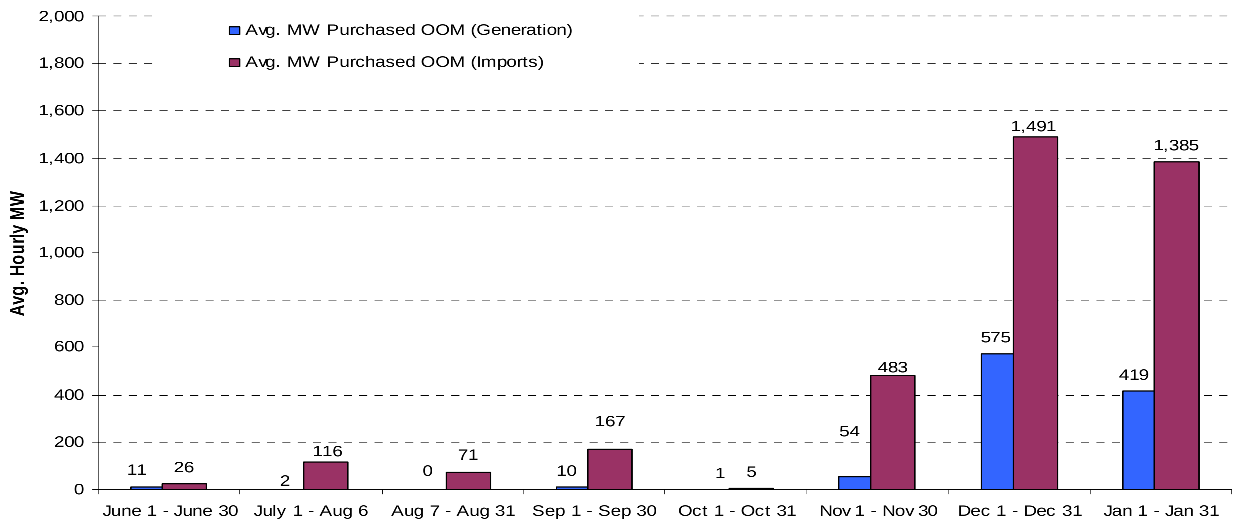
* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)

III. Out of Market Calls (OOM)

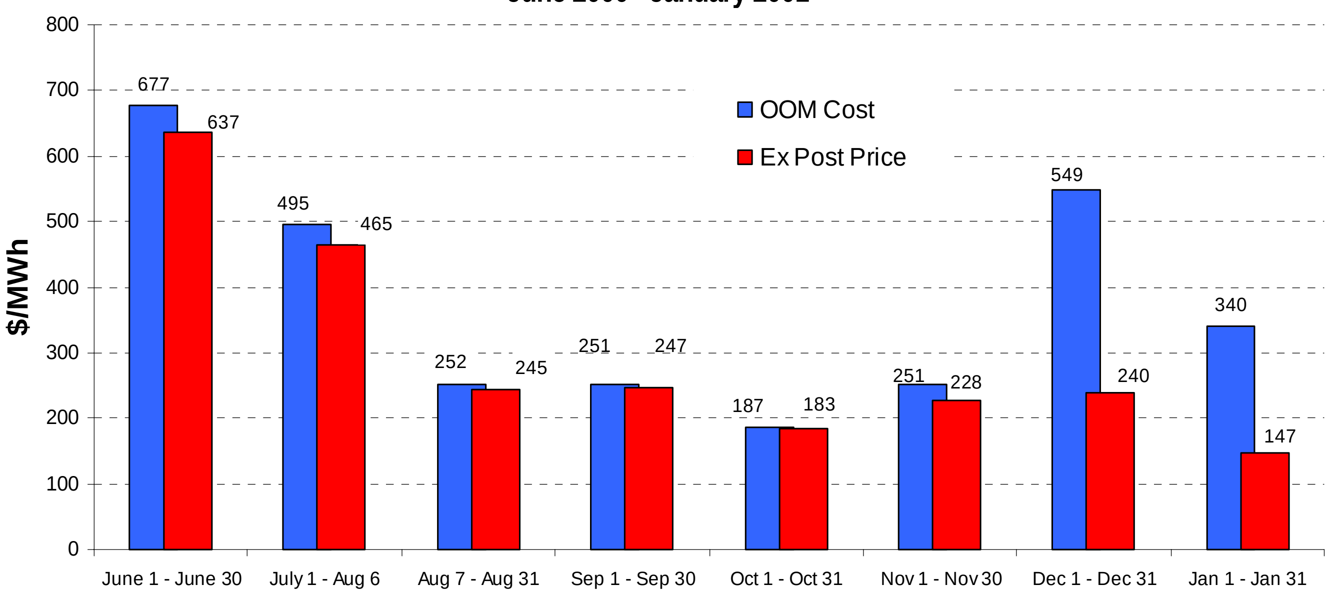
January out-of-market calls remained high due to general system shortages and bilateral real time purchases by California Department of Water Resources being recorded as OOM. Natural gas prices remained high compared with historical averages and above average generation outages persisted. As a result, available energy bids in the BEEP stack remained insufficient. These conditions meant increased quantities of energy purchased out of market to ensure reliability.

Average out-of-market costs for January were $340/MWh, compared with the average ex-post price of $147/MWh at the time the calls were made. On an hourly average basis, 1804 MW were purchased out of market in January. The total cost of out -of-market purchases in January were $395 million.

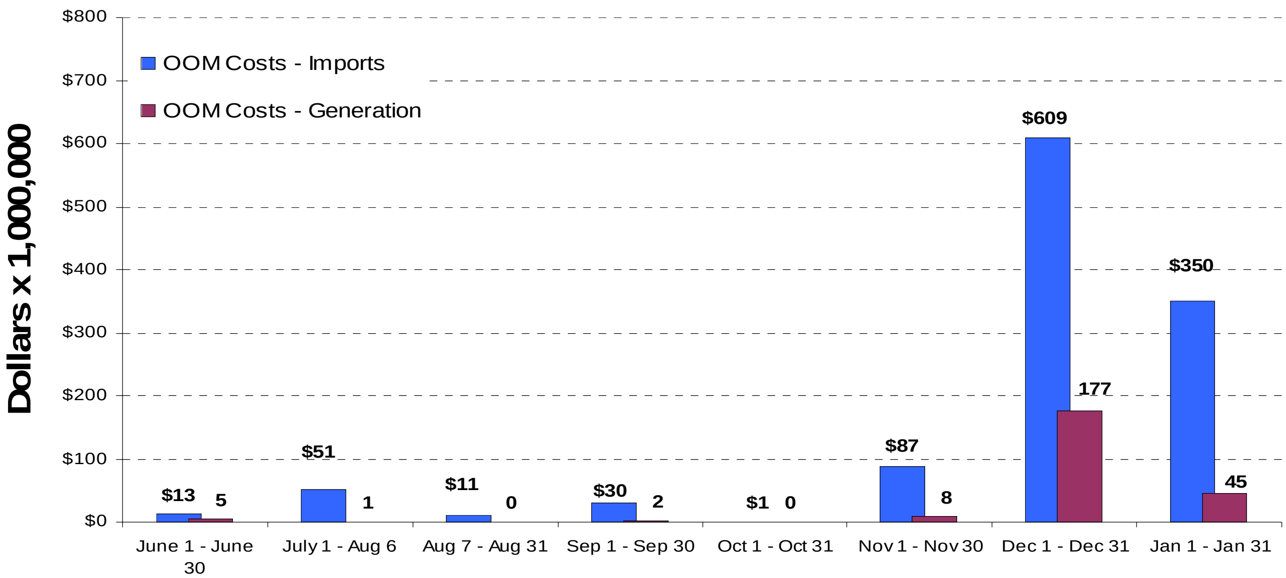
Quantities of Out-of-market Purchases
Average Hourly for June 2000 - January 2001



Comparison of Average Costs for Out-of-market and Real Time Energy Prices
June 2000 - January 2001



Total Out of Market Costs (in millions of $)



IV. Inter-zonal Congestion Management Markets

Export congestion to the Northwest subsided somewhat in January compared with December, as did import congestion from the Southwest. 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 January 2001

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
COI (Export)	13%	18%	15%	$53.47	$73.55	$61.76
NOB (Export)	13%	32%	19%	$80.97	$89.82	$85.90
Path 15 (S-N)	58%	46%	54%	$65.36	$105.65	$76.83
Sylmar-AC (S-N)	5%	6%	6%	$30.00	$30.00	$30.00

- Total Path 15 congestion decreased to 54% in January, down from 76% in December. All of the congested hours were in the S-N direction. Of the congested hours, 27% were in the off-peak period. Day-ahead congestion charges on Path 15 averaged $76.83/MW, a decrease from the December average of $114.53/MW.

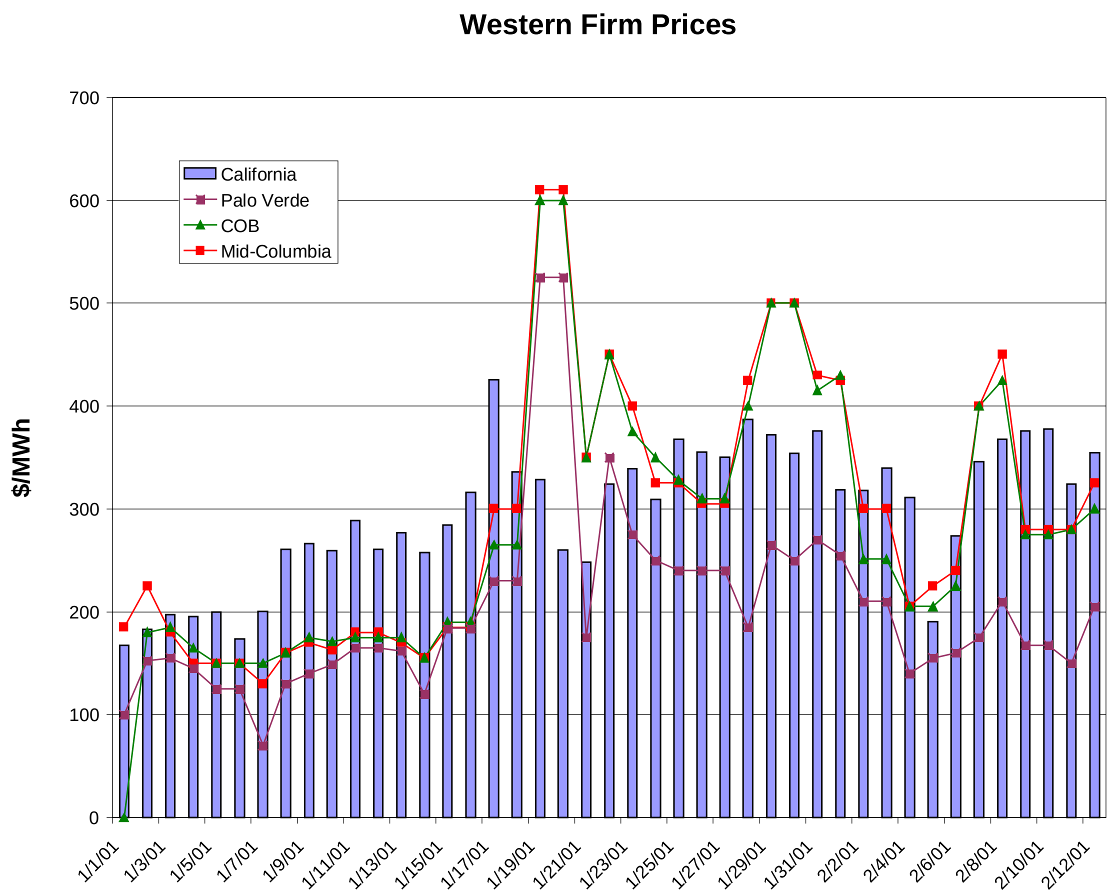
- There was no import congestion on the southwest paths in January. Export congestion to the Northwest dropped considerably, with COI at 15%, down from 24%, and NOB at 19%, down from 50%. Average congestion charges on NOB increased from $67.08/MW to $85.90/MW and increased on COI to $61.76/MW from $38.54/MW.

- Total congestion costs for January were about $30.8 million, a substantial decrease over the December costs of about $103.4 million and a substantial increase compared with the January 1999 cost of $6.6 million. Path 15 and NOB incurred the largest congestion costs with a totals of about $21.7 million and $4.0 million.

V. <u>Western Regional Market Prices</u>

Western Regional Market Prices

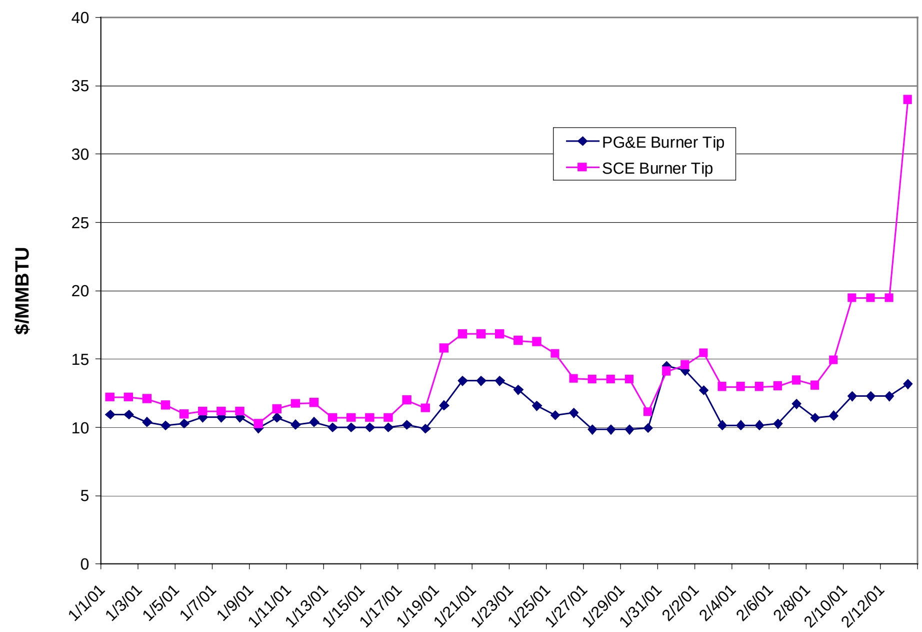
Western peak power prices remained high starting the month with peak power prices just above the $150/MWh California soft cap in the North and just below the soft cap in the South. Regional prices increased significantly during the third week of January due to cooler weather and increased generation outages in the Northwest. Prices in the North reached as high as $500/MWh on January 20th and 21st while prices in the South reached $250/MWh. In February, prices leveled off at the $250-$200/MWh level in the North as generation units began to come back online and milder weather was forecast. Prices in the South leveled off at the $150/MWh level.



Natural Gas Prices

Natural gas prices in California have remained high through the first part of the year, although not nearly as high as the unprecedented levels seen in mid-December. Prices through mid-January leveled off in the $10 to $12/mmbtu range. High gas prices are attributed to unusually high demand by gas-fired generation plants and for heating, as well as low storage levels and low hydroelectric generation output.

California Natural Gas Spot Prices

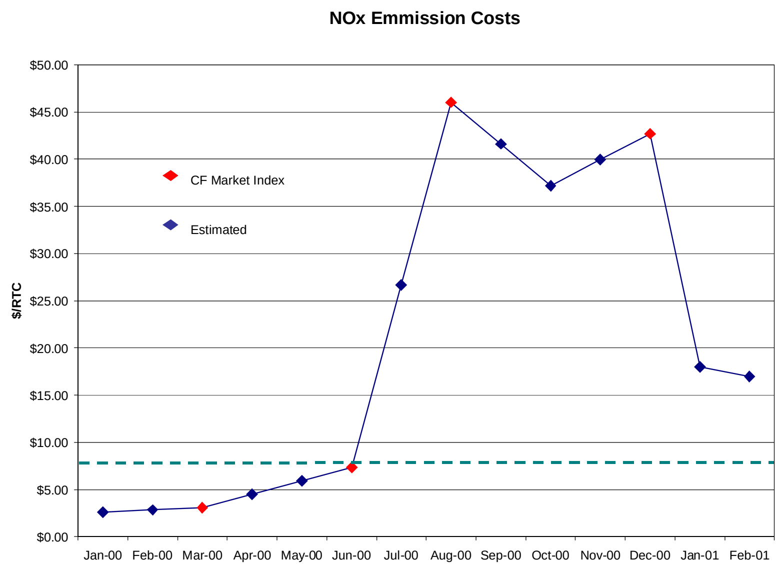


Southern California Border prices increased in mid-January and soared in mid-February by nearly \$5/mmbtu due to the prospect of more stringent balancing requirements on Southern California Gas Co.'s system. SoCalGas' storage levels continue to fall under pressure from cold weather and high generation load. SoCalGas could be required to maintain a 90 percent daily balancing requirement if storage drops below key threshold levels.

NOx Emissions Prices

On January 19, 2001 the AQMD Governing Board gave preliminary approval to five initiatives to modify RECLAIM, the region's emissions trading market, to help stabilize RECLAIM credit prices and reduce the cost of compliance for electric industry while still achieving air quality reductions. The action is expected to remove the influence of power plants' demand on the RECLAIM program while assuring adequate power supply. The five initiatives include:

1. Adopt new or modified AQMD rules that:
   a. Separate major power plants from the rest of RECLAIM companies through 2003 and require them to install air pollution control equipment on an expedited schedule;
   b. Create a pilot RECLAIM Air Quality Investment Program through 2003 where certain companies could obtain additional NOx credits by paying \$7.50 per pound of credits into the program. AQMD would use the funds to obtain equivalent emissions reductions;
2. Pre-fund the RECLAIM Air Quality Investment Program with a loan;
3. Continue to seek abatement orders for companies that have exceeded their RECLAIM allocations, imposing appropriate penalties and requiring expedited installation of pollution control equipment;
4. Initiate outside peer review of changes to the RECLAIM market structure; and
5. Convene a RECLAIM Rule Development Working Group.



At the start of the year, price of NOx RECLAIM credits were relatively low at around $4/RECLAIM Trading Credit (RTC). Then, due to the extremely high demand for electricity, power plants increased their production and emissions and bought most of the available NOx RECLAIM credits. As a result of the increased demand and reduced supply, the price of year 2000 NOx credits increased more than tenfold to more than $45/RTC. Since the preliminary approval of the modifications to the RECLAIM market, NOx prices have dropped dramatically from the $45/RTC range to less than $17/RTC. The price is expected to capped at $7.50 per pound later this spring ,for electric generation, as the AQMD modifications are put in place.

VI. Performance of the FTR Market in January 2001

New FTRs Resulting from Conversion of Existing Transmission Rights

The city of Vernon received FTRs on the following paths and directions as a result of converting 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 December 28, 2000. The effective start date of these FTRs was January 1, 2001.

FTR Auction for 2001-2002

The FTRs released in the first FTR auction conducted in November 1999 are valid through March 31, 2001. The second FTR auction was conducted on January 16-18, 2001 for FTRs with validity date beginning April 1, 2001 through March 31, 2002. The following table summarizes the FTR quantities and prices.

FTR Auction for April 1, 2001 through March 31, 2002

Item #	Branch Group	Direction		FTR MWs (99.5% Firmness)	Target Price $/MW	Seed Price $/MW	Final MWs Sold	Final Price $/MW (12 months)	Total ($)
		From	To						
1	CFE (Import)	MX	SP15	408	$0	$100	408	$300	$122,400
2	CFE (Export)	SP15	MX	408	$0	$100	408	$255	$104,040
3	COI (Import)	NW1	NP15	600	$5,392	$1,078	600	$3,234	$1,940,400
4	COI (Export)	NP15	NW1	56	$6,606	$1,321	56	$47,537	$2,662,072
5	ELDORADO (Import)	AZ2	SP15	707	$13,401	$2,680	707	$19,028	$13,452,796
6	ELDORADO (Export)	SP15	AZ2	626	$0	$100	626	$2,130	$1,333,380
7	IID – SCE (Import)	II1	SP15	600	$180	$100	600	$625	$375,000
8	MEAD (Import)	LC1	SP15	461	$2,344	$469	461	$2,386	$1,099,946
9	MEAD (Export)	SP15	LC1	430	$4,145	$829	430	$7,327	$3,150,610
10	NOB (Import)	NW3	SP15	431	$4,322	$864	430	$3,843	$1,652,490
11	NOB (Export)	SP15	NW3	29	$11,242	$2,248	29	$64,069	$1,858,001
12	PALOVRDE (Import)	AZ3	SP15	1,822	$14,501	$2,900	1,819	$6,960	$12,660,240
13	PALOVRDE (Export)	SP15	AZ3	796	$0	$100	796	$14,100	$11,223,600
14	PATH 26 (S=>N)	SP15	ZP26	199	$2,540	$508	199	$2,564	$510,236
15	PATH 26 (N=>S)	ZP26	SP15	1,727	$44,311	$8,862	1,727	$17,724	$30,609,348
16	SLVRPK (Import)	SR3	SP15	10	$738	$148	10	$2,100	$21,000
17	SLVRPK (Export)	SP15	SR3	10	$365	$100	10	$28,374	$283,740
18	VICTRVL (Import)	LA4	SP15	938	$840	$168	938	$168	$157,584
19	VICTRVL (Export)	SP15	LA4	221	$595	$119	221	$760	$167,960
			Total	10,479			10,475		$83,384,843

Table column definitions:

FTR MWs: The amount of FTRs in MW released on each branch group and direction is based on the New Firm Use capacity (NFU = total transmission capacity - ETCs) available at least 99.5% of the time during the year, based on the historical operating capacity of the line during the most recent 12 months prior to announcement of the FTR quantities.

Target Price: The target price is the congestion revenue generated per MW of NFU during the most recent 12 months prior to announcement of the FTR quantities.

Seed Price: The seed price for each branch group is the starting price of the simultaneous multi-round auction. It is set to 20% of the Target Price, but not lower than $100/MW per year.

Final MW Sold: This is the final MW clearing the auction. The small difference (4 MW) is due to the residual FTR allocation option exercised in the auction.

Final Price: This is the market-clearing price in $/MW per year. The comparison of the final price and the target price indicate to what extent the bidders value the FTRs on the particular path and direction compared to the congestion revenues generated last year.

FTR Concentration

For the FTRs, expiring on March 31, 2001, apart from the conversion of Vernon ETCs to FTRs, there were no secondary FTR market transactions and no new FTR SC assignments in January 2001. Thus there is no change in FTR ownership and control concentration to report.

For the new FTRs auctioned for the period April 1, 2001 – March 31, 2002, the Following table shows the FTR ownership concentrations at or above 25%.

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 ownership concentration on some paths appears excessive. Although position limits (at 37.5%) are contemplated for FTRs to be released in the subsequent years, this limit was not enforced in the first two FTR auctions in view of relatively lower volume of FTRs released (at 99.5% availability) than what is contemplated for the future FTR auctions (all available NFU to be released in a combination of annual and monthly FTR auctions.)

FTR Scheduling

Thus far, on most paths the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges.

VII. Issues Under Review and Analysis

1. **Market Power Monitoring and Mitigation.** In response to FERC's request, the DMA developed a draft market power monitoring and mitigation plan that was discussed at the FERC Technical Conference on January 23, 2001. Based on comments from the conference participants and comments from stakeholders discussions on February 13, 2001, DMA filed additional comments for FERC consideration as part of the input being solicited by FERC staff as it prepares its own market power monitoring and mitigation plan for California due on March 1, 2001.

   The main elements of DMA's proposed plan are: 1) Forward contracting threshold for suppliers to avoid strict market power mitigation; 2) Availability requirements on the suppliers to mitigate exercise of market power through physical withholding along with Available Capacity Reserve (ACR) contracting on Load Serving Entities to identify adequate generation to met seasonal load needs; 3) Local market power mitigation, and 4) Resource specific bid caps (with a margin) in the real-time. The suppliers that satisfy the forward contract threshold option, enjoy higher margins than those who do not, and can collect the MCP. The suppliers who elect not to satisfy the forward contract thresholds, would be paid as- bid.

   The main elements of the draft Market Power Mitigation Plan is intended to support the State efforts to negotiate long-term energy contracts. The ISO's Market Power Mitigation Plan imposes resource specific bid caps on spot market supply bids, thereby reducing significantly their profit opportunities in the spot market. With less profit opportunities available in the spot market, suppliers should be willing to enter into long-term energy contracts at a more just and reasonable price. In addition, the availability standards should insure that generator are fully available to supply power, and outages are coordinated in advance with the ISO. The state long term contracts will go toward meeting the ACR contracts requirement. In addition the ACR will be phased in for 2001 and 2002 so this feature will not have an impact on the State's negotiating efforts. The other elements of DMA's proposed plan should not impact the State's contracting efforts.

   Further development of how to best implement various elements of a market power mitigation plan are being discussed with the staff of the Electricity Oversight Board and the California Public Utility Commission.

2. **Adjustment Bid Insufficiency.** There has been a substantial reduction of the volume of Adjustment Bids after the closure of the PX. This has made it impossible for the ISO to manage congestion in the forward markets, particularly on the internal paths, and specifically Path 15. Although Inter-SC Trade Adjustment Bid (ISTAB) was implemented at the request of market participants, and was expected to increase the volume in the Adjustment Bid market, it has failed to do so thus far. Faced with Path 15 south to north congestion, and highly inadequate volume of Adjustment Bids, the ISO's congestion management software regularly curtails the scheduled flow on Path 15 through infeasible adjustments including increasing the scheduled generation of limited energy (hydro) resources in NP15, reducing generation below technical lower operating points (e.g., Diablo Canyon), and curtailing load schedules that are not dispatchable. This simply delays actual congestion management to real time, and results in real-time penalties for both load whose schedule was curtailed, and energy-limited generation that can not generate according to the infeasible schedule assigned to it by the ISO software. The DMA has collaborated with Market Operations to develop a solution with the following elements: 1) Work with DWR to schedule the energy it procures for the UDC load in the day-ahead market (rather than real-time), and to the extent possible, schedule it so as to create a counter schedule on Path 15; this would reduce Path 15 congestion, but would also generate counter-scheduling congestion revenues that can reduce the overall cost of CDWR procurement. 2) Encourage CDWR (under its CERS SC ID) to submit

Adjustment Bids along with its day-ahead schedules to help relieve congestion; 3) Reflect the true cost of wheeling on Path 15 by the entities exporting power or wheeling through ISO control area by increasing the minimum Default Usage Charge (DUC), which is currently set at $30/MWh. The DMA suggested a formula whereby the minimum DUC would increase as the volume of Adjustment Bids is reduced compare to that needed to alleviate congestion. According to the DMA formula, the minimum DUC would start at $250 with no adjustment bids (consistent with the current Tariff), and vary linearly from $250 to $30 as the volume of the Submitted Adjustment Bids increases, as opposed to dropping to $30 immediately as the Adjustment Bid volume becomes non-zero (the current practice).

3. **Splitting the BEEP Stack.** With the implementation of the FERC soft cap, there has been a noticeable reduction in the participation of the energy-limited resources in ISO's Operating Reserve (OR) markets (Spin and Non-spin). Prior to the implementation of the soft cap these resources could submit high-priced energy bids to ensure they are not dispatched except under emergency conditions. This is no longer a viable option, since if dispatched, they would need to justify costs above the soft cap as required in the FERC Order. Energy-limited resources, particularly hydro generation are capable to supply under emergency conditions, are highly suitable as OR providers, and their absence in the OR market must be remedied as soon as possible. To remedy the problem one immediate solution proposed is splitting the BEEP stack into Operating Reserves (OR) which would not be dispatched and Imbalance Energy (IE) which would be dispatched. However, there is concern that this would thin the IE stack and make it subject to more manipulation. An alternative proposal being reviewed is to create a single stack with all energy-limited bids moved to the end of the BEEP stack and treated as price takers. Unless flagged as energy-limited, the OR bids would not be skipped when in economic merit order, as long as there is adequate 10-minute responsive supply in the BEEP stack to meet the Minimum Operating Reliability Criteria (MORC) regardless of whether it is labeled as OR or otherwise. As part of the DMA's proposed solution, a software tool would have to be implemented to help the ISO Operators observe the total 10-minute supply in the BEEP stack in order to decide when to skip or dispatch for IE the energy from OR bids that do not carry the energy-limit flag.