CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: January 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 December 2000.

DECEMBER HIGHLIGHTS

- A chaotic energy market in December was characterized by general system shortages, skyrocketing natural gas spot prices, significant generation unit outages, a drop in available imports with energy prices increasing in the Northwest, and little available energy bids in the BEEP stack to meet system need for real-time imbalances. These conditions led to the ISO making an emergency filing of Amendment 33 on December 8th which implemented a soft cap of $250/MW in order to maintain system reliability. The intent was to increase the volume in the BEEP stack and avoid reliance on increasing volumes of energy having to be purchased out of market.. With the Amendment accepted by FERC, payments above $250/MW would be subject to scrutiny and cost-justification.

- Temperature conditions were comparable to 1999. The monthly peak reached 33,672 MW, down 1.9% from December 1999, while total energy increased by 0.7% from the previous year. Average daily peaks reached 31,270 MW, up from 30,900 MW in November.

- The estimated total energy and A/S cost for December was $6.3 billion, or about $326/MWh of load served, compared to about $3.2 billion ($171 per MWh of load served) in November. The dramatically higher energy costs in December were caused by increased energy prices which were fueled by (1) high scheduled and forced outages (2) drop in available imports from the Northwest, (3) soaring high natural gas prices, and (3) low hydro generation within California,

- The average constrained PX price for the month was $251, up 770% from $28.95/MW in December 1999 and up 74% from the $144/MWh average in November. System market clearing prices averaged $243/MW, system as-bid prices averaged $570/MW, total BEEP real time prices (market clearing and as-bid) averaged $383/MW, out-of-market prices averaged $461/MW, and total real time prices (total BEEP and out-of-market) averaged $423/MWh.

- December prices (weighted by volume purchased) in the ancillary service markets increased sharply compared to November. Regulation up, regulation down, spinning reserve, and non-spinning reserve prices all increased from 127% to 650% compared with November. Replacement reserve prices increased by 64%.

- Ancillary service costs increased to $22.65 per MWh of load compared to the November value of $6.13/MWh and the December 1999 value of $0.55/MWh. Total A/S costs were about $440 million in December 2000, which is about 7.5% of total wholesale energy costs, compared to the November rate of 3.7%.

- Natural gas prices increased sharply in December, from approximately $18/MMBTU at the beginning of the month to $60/MMBTU by December 11th, and back down to $12/MMBTU by the end of the month, averaging roughly $26/MMBTU.

- Export congestion to the Northwest prevailed through December. Congestion on COI shifted from imports in November to Exports in December while the export congestion on NOB increased markedly compared to November. Import congestion from the Southwest was varied compared with last month. Path 15 experienced marginally higher congestion in the South to North direction, which contributed to higher prices in the North for the month. The following table summarizes congestion rates and average congestion charges by branch group for the day-ahead market.

KEY MARKET CONDITIONS FOR DECEMBER 2000

I. California Wholesale Energy Markets

- **Loads –** December loads increased from November due to colder temperatures. Monthly system energy loads totaled 19,412 GWh, a 0.7% increase from December 1999. The peak load for the month reached 33,672 MW, a 1.9% decrease over December 1999 levels, occurring at HE 18 on December 18. Daily peak loads averaged 31,270 MW, a 1.5% decrease over December 1999.

- **Wholesale Energy Prices** – Facing virtually no supplies in the real-time market to meet system imbalances, the ISO filed on December 8th Amendment 33 with FERC which allowed for a soft price cap of $250/MW. A soft cap allowed as- bid payments above $250 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 created several prices that can be reported. There is the market clearing price for bids under the price cap, the as-bid price for bids over the price cap, total BEEP price, out-of-market price, and total real time price. Averages for these five prices for peak, off-peak, and all hours are reported below. More details are provided under *Section IX. Issues Under Review and Analysis* of this report.

	Market Clearing Avg. Price	As-bid Avg. Price	Total BEEP Avg. Price	Out-of-market Avg. Price	All Real Time Energy Avg. Price
Peak	$244	$570	$385	$479	$432
Off-peak	$242	$569	$376	$417	$398
All Hours	$243	$570	$383	$461	$423

Under-scheduling in the day ahead market increased sharply in December compared to what was observed in November. In approximately 99% of all hours in December there was underscheduling. On average, the ISO required nearly 4,200 MW of incremental generation each hour.

Significant real time congestion persisted on Path 15 in the S-N direction, occurring during 76% of all hours.

Natural gas spot prices skyrocketed in December, from approximately $18MMBTU at the beginning of the month to $ 60/MMBTU on December 11th, and back down to $12/MMBTU by the end of the month, averaging $26/MMBTU over the month. This is a 800% increase compared with the $2.86/MMBTU in December 1999. High natural gas prices and high emission costs were major drivers of high PX and ISO energy prices in December.

- Market clearing energy prices by zone and period are listed in Table I. Note that the statistics reported for Real Time Price 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 1: Energy Price Summary for December 2000 (MCP Only)

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$237.77	$241.51	$234.02	$234.02	21%
Off-Peak	$217.84	$236.63	$199.06	$199.06	39%
Total	$231.13	$239.88	$222.38	$222.38	27%
PX Constrained					
Peak	$279.00	$319.75	$238.24	$236.06	77%
Off-Peak	$239.71	$286.71	$192.72	$192.72	81%
Total	$265.92	$308.75	$223.08	$221.63	78%

II. Ancillary Service Markets

Ancillary Service Prices

- During December Regulation Up prices hit the price cap 102 hours in the day ahead markets, Regulation Down prices hit the price cap 102 hours in the day ahead markets, Spinning Reserve prices hit the price cap 26 hours in the day ahead markets, Non-spinning Reserve prices hit the price cap 89 hours in the day ahead markets, and Replacement Reserve prices hit the $100/MW cap 221 hours in the day ahead markets. Price cap hits in the hour ahead markets were comparable.

- The ISO procured most of its A/S requirements in the day-ahead market, with between 79% and 87% of A/S MW quantities being procured in the day-ahead market (65% for Replacement Reserve). Table 2 below summarizes weighted average prices and quantity procurements for December 2000 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 – December 2000

	Day-Ahead Market (all hours)	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$157.17	$165.05	$158.19	541	80	87%
Regulation Down	$113.36	$ 153.32	$ 119.09	528	88	86%
Spin	$ 146.77	$ 166.76	$ 150.64	770	185	81%
Non-Spin	$ 163.76	$ 150.90	$ 161.05	616	164	79%
Replacement	$ 96.89	$ 99.29	$ 97.72	991	529	65%

Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – December 2000

	NP15		SP15		Percent of Hours with Zonal Procurement
	Peak	**Off Peak**	**Peak**	**Off Peak**	
Regulation Up	$ 150.54	$ 107.80	$ 209.47	$ 220.09	10%
Regulation Down	$ 80.40	$ 200.13	$ 154.86	$ 219.82	0%
Spin	$ 159.57	$ 128.03	$ 175.31	$ 168.73	10%
Non-Spin	$ 138.49	$ 116.23	$ 164.89	$ 174.32	9%
Replacement	$ 91.46		$ 113.49		12%

Ancillary Service Costs

- A/S costs in December were $439 million compared to the November total of $114 million. December A/S costs were about 7.5% of total energy costs. Day ahead A/S prices in December were considerably higher than November, with regulation up prices increasing by 130%, regulation down increasing by 127%, spinning reserve increasing by 327%, non-spinning reserve experiencing a 650% increase, and replacement reserve increasing by 64% from November prices.

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%**

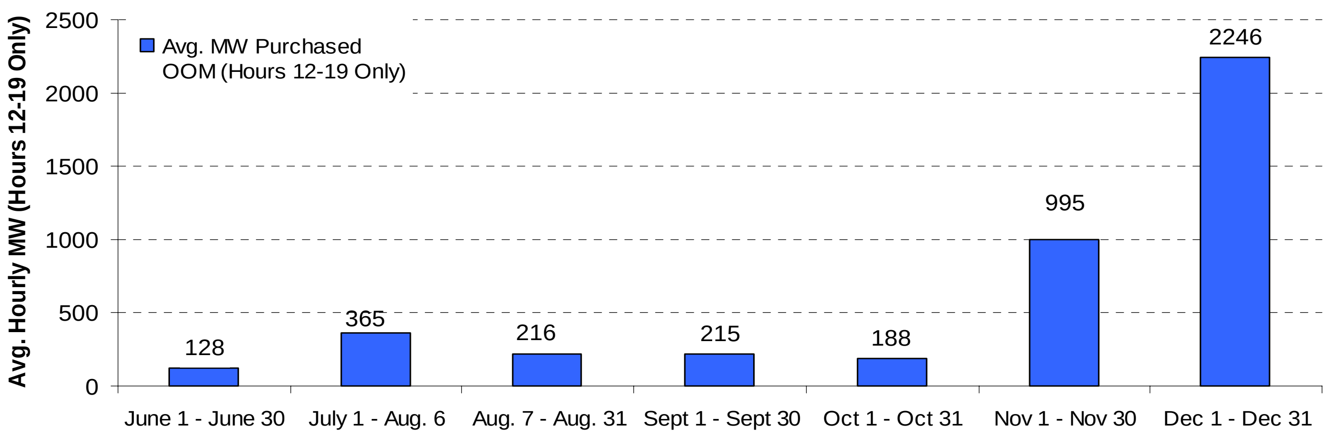
* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)

III. Out of Market Calls

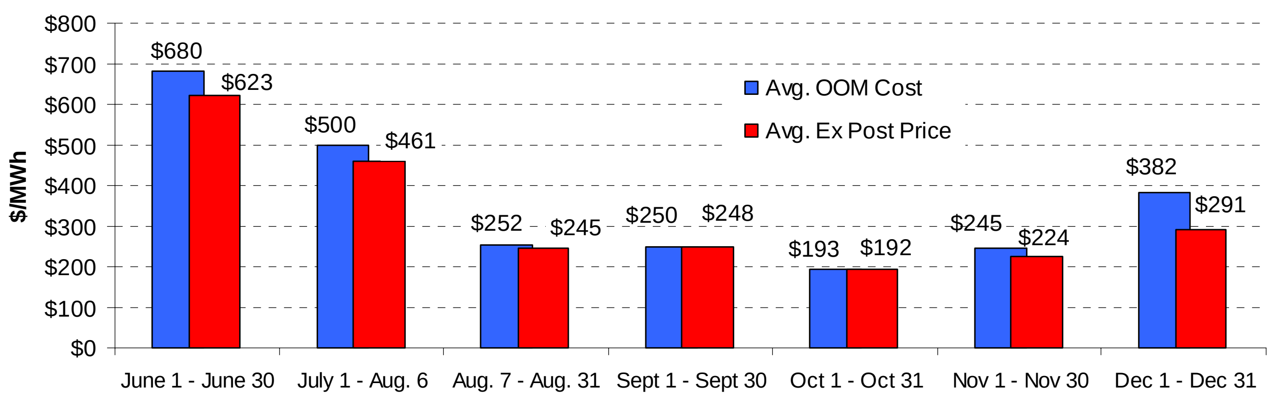
Due to general system shortages, there were increased out-of-market purchases by the ISO in December. As production costs were driven up by natural gas price increases and emission costs, above average outages persisted, and energy prices in the surrounding areas increased slowing the available quantity of imports, the available energy bids in the BEEP stack dwindled. These conditions led increased quantities of energy purchased out of market to ensure reliability.

Average out-of-market costs for December were $382/MWh, compared with the average ex-post price of $291/MWh at the time the calls were made. On average, 2246 MW were purchased each peak hour in December (HE 12 - 19). There were a total of 1.536 GWh of energy purchased out-of-market in December at a total cost of $710 million. Due to the manual nature of the computations, we are currently developing the total monthly OOM costs trends for the past few months. The charts below summarize some of these trends in OOM purchases by the ISO in November and the first week of December.

Average Hourly Out-of-market Purchases
June - December 2000 (Hours 12 - 19 only)



Comparison of Average Costs for Out-of-market and Real Time Energy
June - December 2000



IV. Inter-zonal Congestion Management Markets

Export congestion to the Northwest prevailed through December. Congestion on COI shifted from imports in November to Exports in December while the export congestion on NOB increased markedly compared to November. Import congestion from the Southwest was varied compared with last month. Path 15 experienced marginally higher congestion in the South to North direction, which contributed to higher prices in the North for the month. The following table summarizes congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for December 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Export)	21%	31%	24%	$44.65	$30.10	$38.54
Mead (Import)	11%	4%	9%	$35.18	$9.70	$31.65
NOB (Export)	42%	67%	50%	$54.60	$67.08	$60.11
Palo Verde (Import)	7%	20%	12%	$102.26	$67.38	$82.21
Path 15 (S-N)	73%	82%	76%	$114.68	$114.27	$114.53
Path 26 (N-S)	10%	0%	7%	$30.00	$0.01	$22.10

- Total Path 15 congestion increased to 76% in December, up from 74% in November. All of the congested hours were in the S-N direction. Of the congested hours, 24% were in the off-peak period. Day-ahead congestion charges on Path 15 averaged $114.53/MW, an increase from the November average of $87.50/MW.

- December import congestion on the southwest paths was mixed compared with November. Palo Verde import congestion decreased from 33% to 12%, import congestion on Eldorado dropped from 17% to zero, while import congestion on Mead increased from zero to 9%. There were no other SW branch groups with any significant day ahead congestion. Average congestion prices for Palo Verde and Mead were $82.21/MW and $31.65/MW, respectively. Import congestion from the North dropped to zero, with all congestion occurring in the export direction to the Northwest with COI at 24%, up from10% export, and NOB at 50%, up from 29%. Average congestion charges on NOB decreased from $87.50/MW to $67.08/MW and increased on COI to $30.10/MW from $1.43/MW.

- Total congestion costs for December were about $103.4 million, a substantial increase over the November costs of about $72.4 million as well as the December 1999 cost of $5.4 million. Path 15 and Palo Verde incurred the largest congestion costs with a totals of about $71.4 million and $11.7 million.

V. Western Regional Market Prices

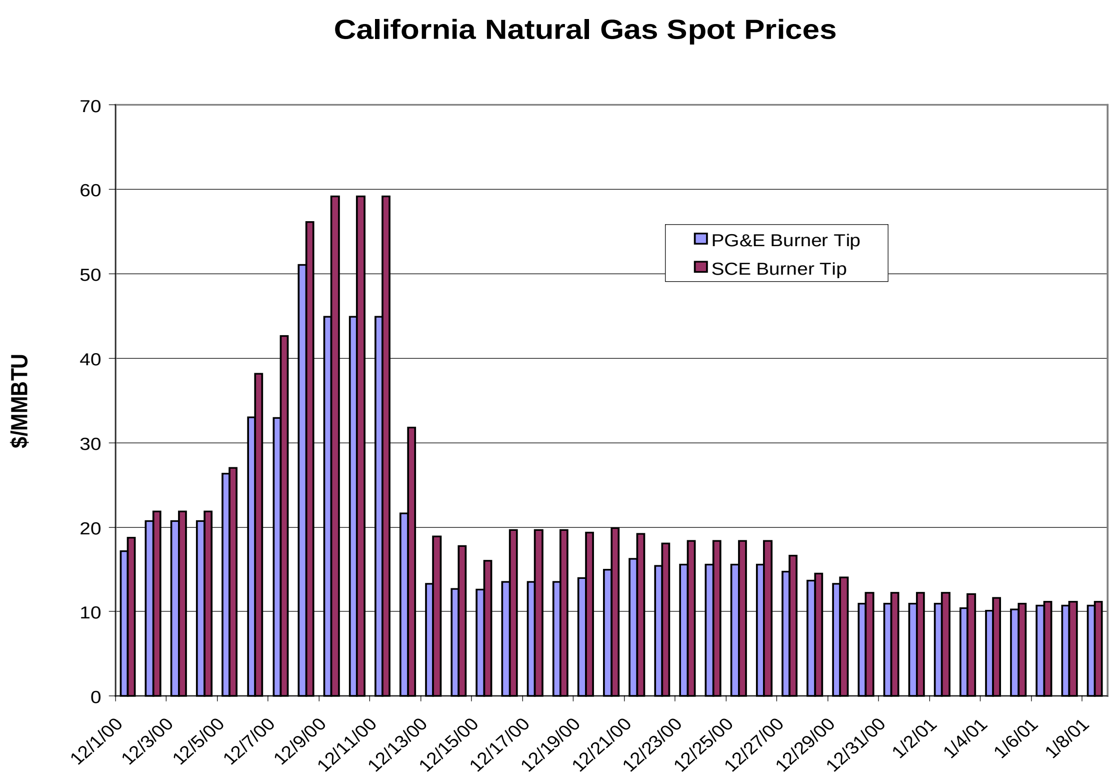
The surrounding regional peak power prices at the beginning of December increased significantly due to expectations of tight supplies. This was compounded by several downed generating units causing supply shortages for the Northwest region. Congestion caused Northwest and Northern California energy to trade at a significant premium to those in the southern half of WSCC.

Prices for power in the Northwest skyrocketed in the first week of December reaching a high ***of $1,200 per megawatt-hour for bilateral trading at the Mid-Columbia trading hub.*** Like California, the Northwest has experienced significant growth, especially in the energy-intensive high tech sector, during the last ten years without corresponding growth in investment in electricity generation and transmission facilities. This was coupled with the lack of available electricity imports from California and a colder than average fall with little rainfall to power hydroelectric facilities. Western peak power prices continued to increase in the second week of December driven by tight supplies, growing heating demand, and rising natural gas prices. Power prices peaked on December 11 where Northwest peak prices rose by as much as $4,200/MWh with some trades posting as high as $5,000/MWh. Off-peak prices gained $2,000/MWh to trade from $2,000 to $2,500/MWh. At these high prices, day-ahead trading was extremely thin in these bilateral as- bid markets with many market participants unwilling to pay the exorbitant prices and opting instead to purchase power real time. Peak power prices fell dramatically throughout the west in mid-December as the extremes in expected temperatures failed to materialize, natural gas prices moderated, and supplies increased in California.

Prices in the Southwest for first week of the new year have leveled off to the $75/MWh range for trades at Palo Verde and $100/MWh in Southern California. Northwest prices have leveled off at the $150/MWh range equal to the FERC soft price cap that went into effect at the first of the year.

VI. Natural Gas Prices

November natural gas spot prices in California increased from $6/Mmbtu to near $20 by the end of the month. However, December spot prices vaulted to over $50/Mmbtu at the PG&E Citygate and to nearly $60/mmbtu at the Southern California Border during the first week of December. The particularly critical price situation was attributed to unusually high demand by gas-fired electricity plants and for heating, as well as low storage levels. Supply to California was also constrained by below normal flow level of the El Paso pipeline system as it recovered from its August rupture and lack of available capacity in other supply systems. There was delayed maintenance on key pipelines flows into California which helped prices in the second week of December to decline as quickly as they increased in the first week. The result was a drop in PG&E Citygate and Southern California Border spot prices to $13.30/mmbtu and $18.90/mmbtu respectively by December 13. Since mid December, prices have leveled off to $10.75/mmbtu at the PG&E burner tip and $11.17/mmbtu at the SCE burner tip as we head into mid January.



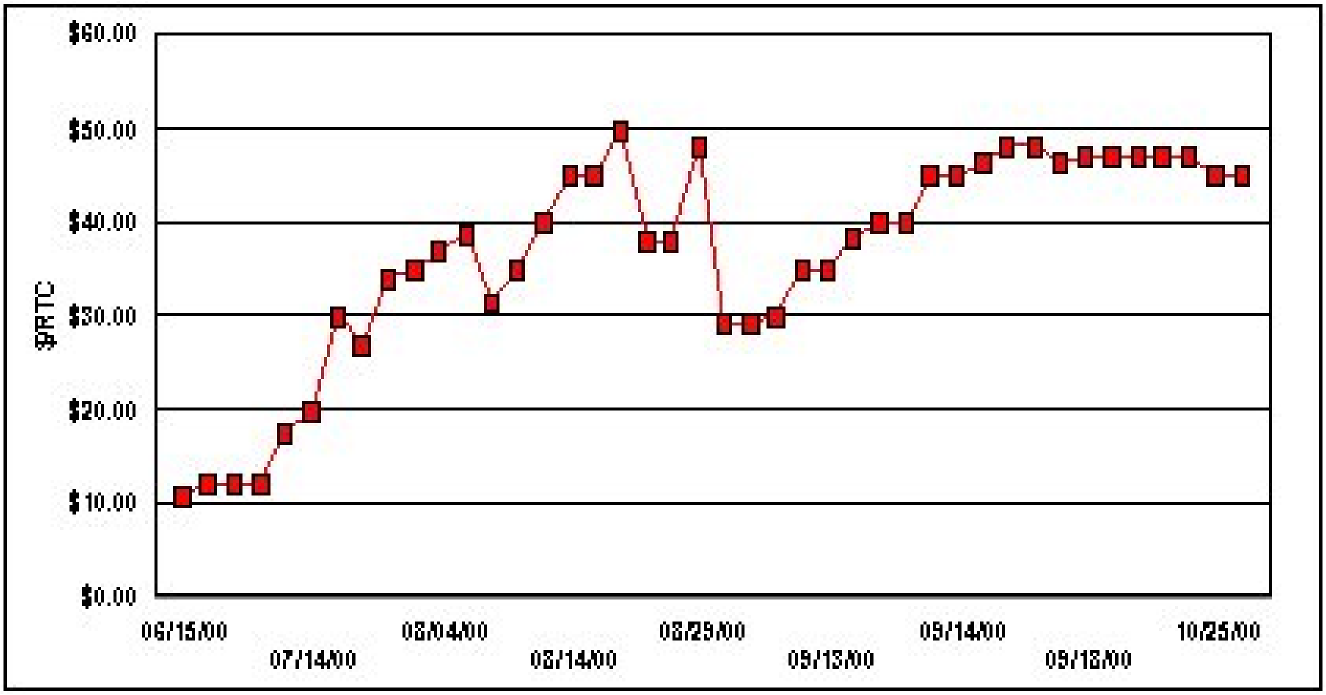
VII. NOx Emission Prices in SCAQMD

The vintage 2000 NOx Reclaim Trading Credit prices have remained high over the past several months. Vintage 2000 NOx RTC prices, which hovered around $1/RTC in January 2000, broke through the $10/RTC mark on June 7, 2000. The $20/RTC mark was reached on July 14; the $30/RTC and $40/RTC levels were reached on September 13, 2000. On September 14, 2000, vintage 2000 NOx RTC prices were at $48/RTC. Subsequently, 155,942 vintage 2000 NOx RTCs cleared at $47/RTC, followed by 20,000 at $45/RTC. NOx RTC prices have remained high and continue to sell in the $40/RTC to $50/RTC range with trades of $46/RTC transacted on December 13, 2000.

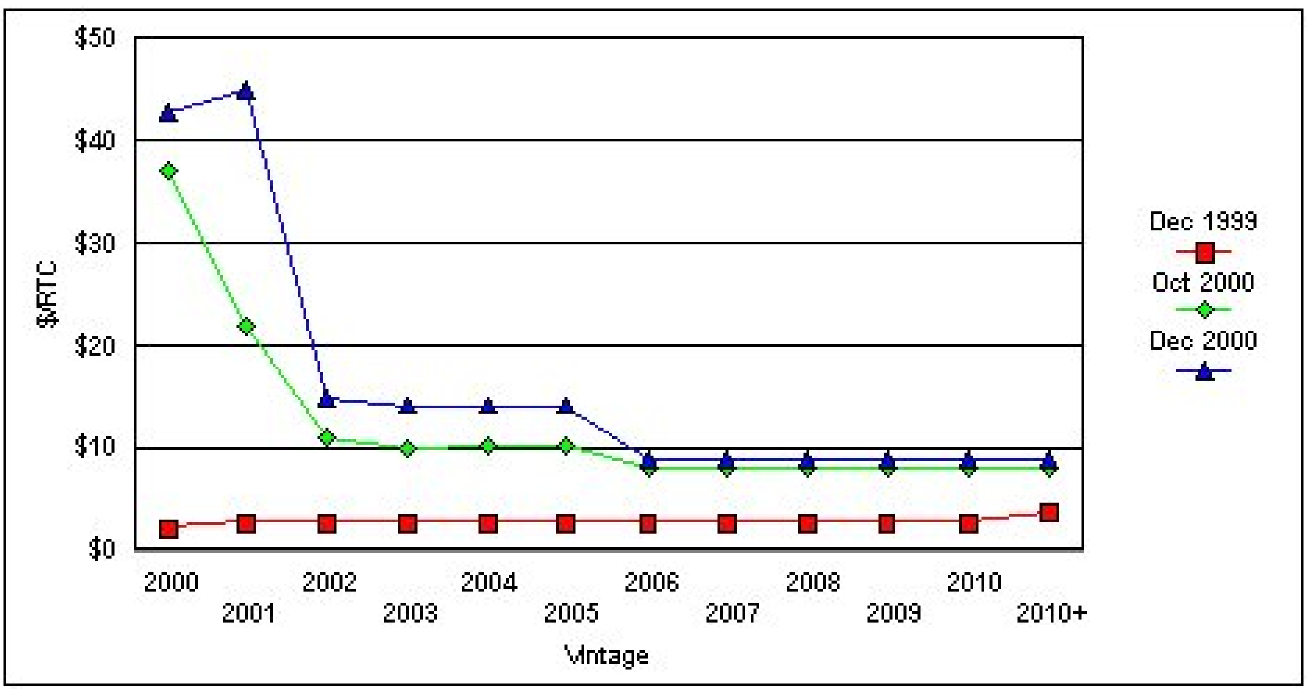
The Market Price Index in emissions trading, an average of the best bid, best offer, and most recent trades, has been increasing for all vintages of NOx RTCs. The most significant NOx RTC MPI increase has been for vintage 2001, which stands at $44.736/RTC -- an increase of 103.7% over October's MPI. The MPI for vintage 2000 stands at $42.69/RTC, an increase of 14.79%. The MPI for vintages 2002 through 2005 rose between 36% and 45% and now stands at between $14.167 and $14.95/RTC. The MPI for vintages 2006 through 2010+ stands at $8.75/RTC, an increase of 9.83% over October's MPI.

According to Cantor Fitzgerald, a SCAQMD appointed advisory committee is diligently pursuing ideas to bring prices down and/or increase the RTC supply. The advisory committee has met twice in the last 30 days and is scheduled to meet two more times in January 2001. The goal of the effort is to present proposals to the SCAQMD Governing Board before the close of the vintage 2000 cycle 1 reconciliation period. Some proposals focus on increasing the supply of RTCs. Increasing supply could be done by securing EPA approval for MSERC-derived RTCs. Alternatively, a public or privately managed fund could be established -- buyers could pay into the fund and relieve themselves of the need to purchase RTCs from the market. The fund manager, according to proponents of this proposal, would then use the collected monies to install new controls on existing in-basin RECLAIM or non-RECLAIM sources (e.g., mobile or area-wide sources). Another proposal for increasing supply would be to free up unused, forfeited RTCs (e.g., those given up as a result of missing data provisions). Another group of proposals focus on the demand side of the market. Proposals designed to reduce the quantity of RTCs sought include: (1) streamlining pollution control permits; (2) fast-tracking CEQA reviews; (3) providing information to sources on available air pollution control options; and (4) providing financial assistance to sources (e.g., using monies collected by the SCAQMD through abatement orders). Other proposals focus on market design issues. For example -- quicker reporting of trades after RTCs have been transacted, as well as quicker reporting by the SCAQMD after the trades have been submitted. SCAQMD staff have cautioned vintage 2000 reconciliation buyers against counting on solutions that require fundamental program changes and/or regulatory amendments. The SCAQMD has urged sources to either secure sufficient RTCs prior to February 28, 2001, or immediately come forward and enter into discussions that may result in an abatement order. Two such orders have so far been agreed to - both mandated the installation of controls and both have resulted in significant payments to the SCAQMD ($14 million and $17 million) that may well be above the cost of acquiring RTCs.

Nox RTC Market Price Index June 2000 – October 2000



NOx RTC Vintage Price Comparison



VIII. Performance of the FTR Market in December 2000

FTR Concentration

There were no secondary FTR market transactions and no new FTR SC assignments in December 2000. Thus there is no change in FTR ownership and control concentration to 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 December 1-31, 2000 is indicated in the following table. Only paths on which FTRs were attached to schedules are listed.

Branch Group	COI EXP	NOB EXP	ELD IMP	IID-SCE	MEAD IMP	PV IMP	SilvPk IMP	Total
MW FTR Auctioned	33	442	694	600	366	1,650	10	9,553
Avg. MW FTR Scheduled	1	28	342	428	8	807	8.5	1,622
% FTR Scheduled	2%	6%	49%	71%	2%	49%	85%	17%
Max MW FTR Scheduled	8	175	405	453	10	979	9	-
Max Single SC FTR Schedule	8	175	405	453	10	600	9	-

Secondary Market Activity

There were no secondary transactions during the month of December.

IX. Issues Under Review and Analysis

1. Develop Generation Availability Standards. The DMA is developing generation availability standards and generation availability requirements in coordination and collaboration with the Department of Outage Co-ordination and other parts of the ISO, and with a view to the experiences of other ISOs. All Eastern ISOs require generation that is not on maintenance or forced outage to be scheduled or bid into the market at full operating capacity. Moreover, they all have some form of generation maintenance coordination in place. These two elements are lacking in CAISO's market. Even the RMR units whose maintenance must be approved by the ISO, have no requirement to schedule or bid all their capacity (i.e., capacity beyond minimum reliability requirement level) into the market. Amendment 33 expanded ISO's authority to require generating units to come on line and follow ISO's dispatch instructions under emergency conditions, and impose penalties for violation. However, no measures are in place to guard against physical withholding under normal or tight supply conditions that are not strictly classified as emergency conditions. The DMA is collaborating with other ISO departments to develop a baseline (based on outage maintenance coordination) for generation availability standards, and is exploring options for penalties and sanctions against capacity withholding.

Another issue that the DMA is investigating is how to distinguish between legitimate and potentially strategic outages. The Eastern ISOs have not developed such standards. The DMA is exploring different options including correlation between forced outages and market prices. For example, it is expected that since legitimate forced outages occur at random, the average price during legitimate forced outage periods in a season or a year should be an unbiased estimate of the seasonal or annual average market price. This could be used to set a standard to compare the average price computed during forced outage hours of a unit or portfolio of a generation owner with the reference unbiased price. If it exceed the standard by a certain margin (e.g., n standard deviations) then penalties could be imposed. The DMA is also exploring other possible approaches to explicitly include or exclude expected levels of forced outages in the baseline used to detect physical withholding.

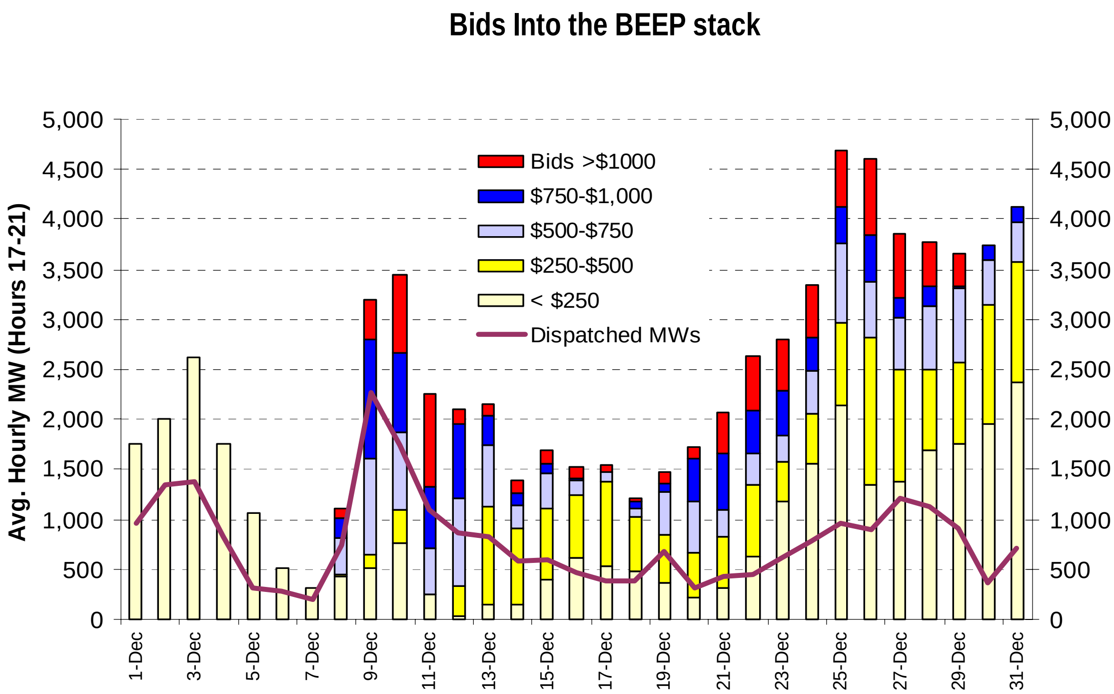
2. **Support FERC Filings and Analyze FERC Orders.** The DMA has analyzed potential issues and/or ambiguities regarding the application of the December 15, 2000 FERC Order to various ISO markets, so that while complying with the Order, the ISO does not encounter implementation problems or inconsistencies in its markets. Prominent among these are how the soft cap should be applied to the Ancillary Services markets, and the potential impact on the Rational Buyer procedure.

DMA is developing a market power mitigation plan to be discussed at the upcoming FERC Technical Conference scheduled for January 23, 2000 which will include proposals to address the impacts of economic and physical withholding .

3. **Modify Market Monitoring Systems in Response to Real Time Market Changes**. The as-bid basis for real time energy over the $250 price cap, combined with the high volume of out-of-market purchases in December created the need for DMA to develop new processes for estimating and tracking total market costs and analyzing market trends. DMA is working closely with Market Operations staff and other parts of the ISO to develop and automate these new processes in order to facilitate DMA's ability to analyze, track and report on total market costs and market trends.

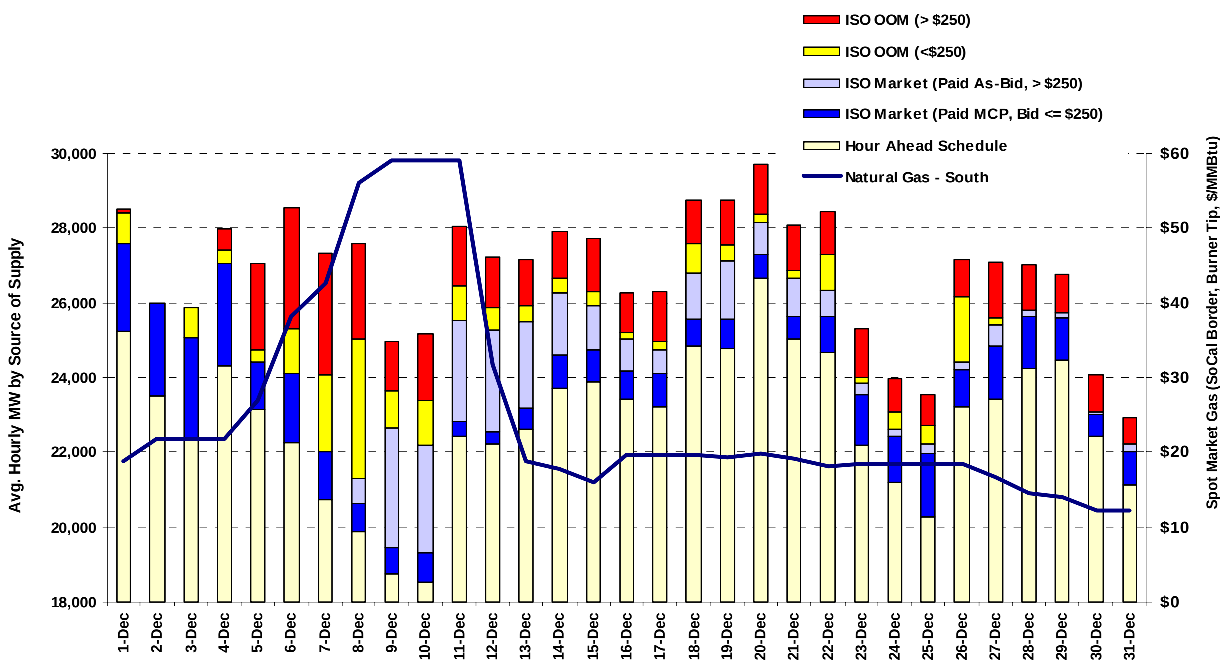
4. **Collaboration with External Investigations.** DMA continues to collaborate with investigations being performed by a variety of outside entities, including the FERC, CPUC, EOB and State Auditor.

5. **Analyze Effects of the ISO's December 8 Filing of Amendment 33 with FERC.** DMA developed the following series of charts to illustrate several key trends leading up to Amendment 33, and the market trends following Amendment 33.



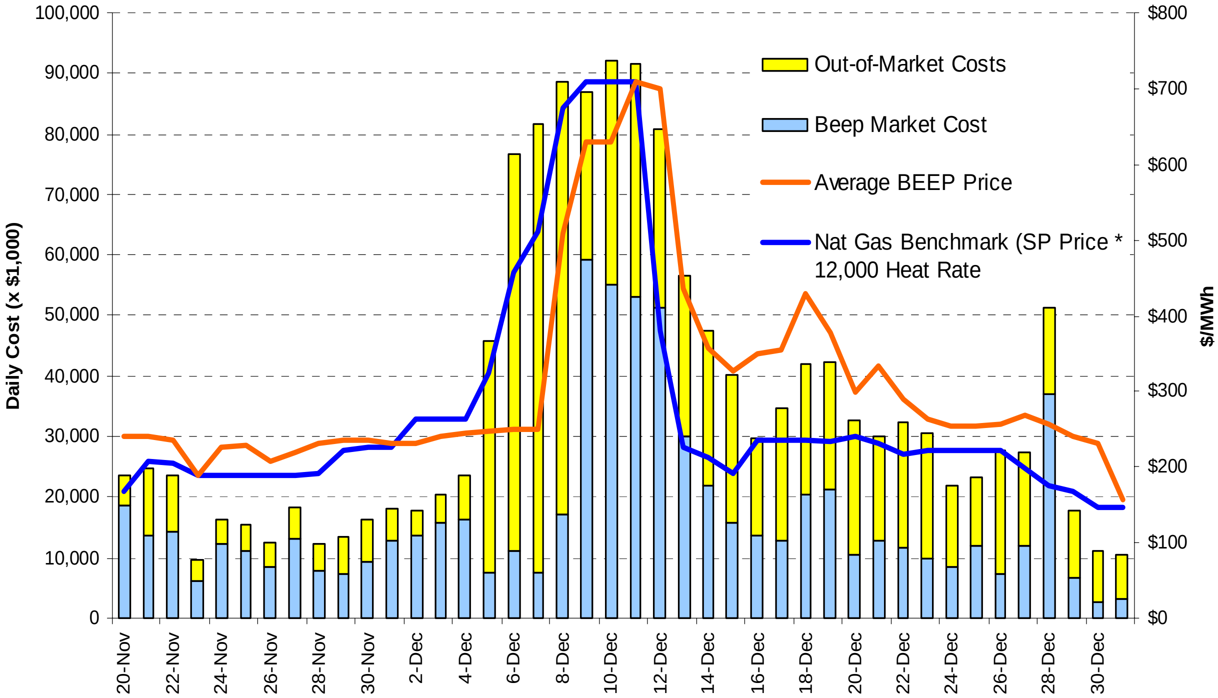
As gas prices rose in the first week of December, bids into the real time energy market became increasingly scarce. A number of suppliers indicted that given gas prices (which rose above $20/Mbtu in the first few days of December), it was uneconomic to offer energy at prices at or below the $250 cap in the ISO's real time energy market. The lack of bids in the real time market – combined with increased underscheduling of loads and generation – forced the ISO to procure increasing amounts of energy *out-of-market*, often at prices above the $250 price cap (see yellow and red sections of bar chart). By December 7, the ISO was procuring an average of over 5,000 MW per hour out-of-market, and only about 300 MW per hour through bids submitted to the real time imbalance market.

Real Time Energy Purchases – Sources of Supply



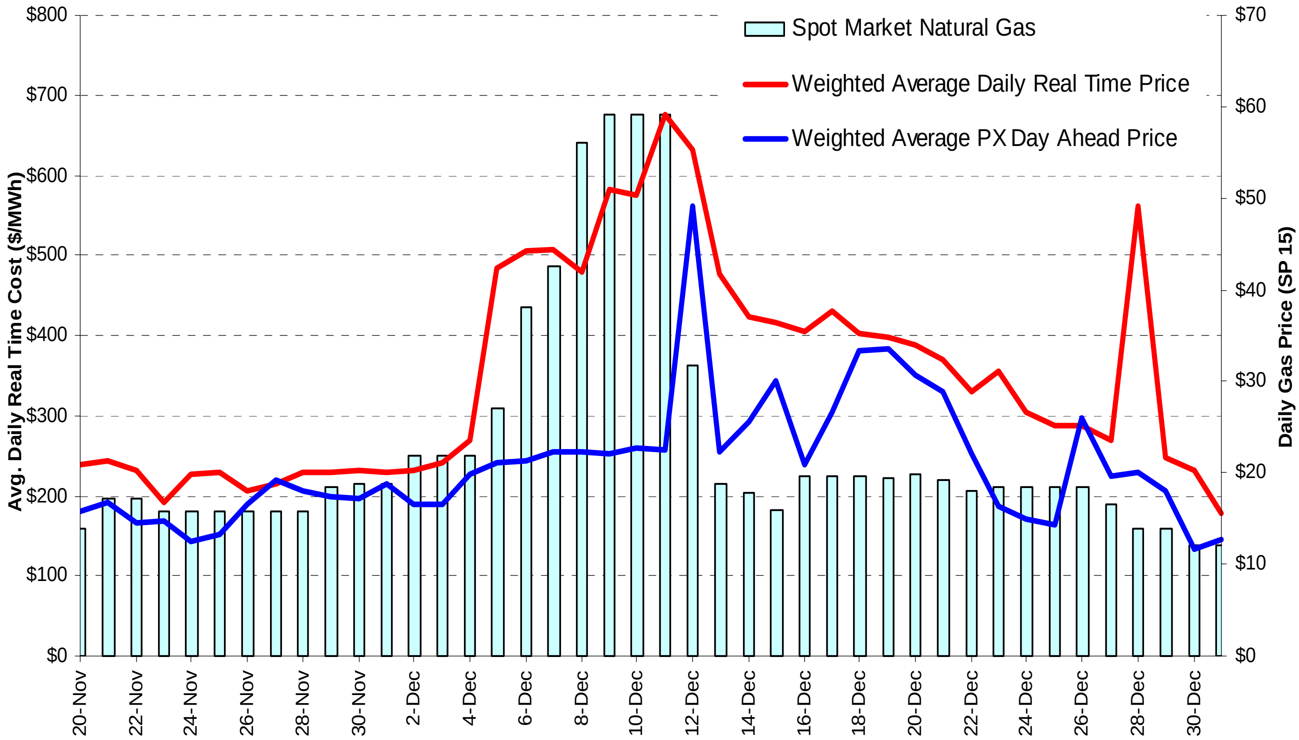
After Amendment 33, the amount of energy bid into the ISO's real time market increased substantially. A large portion of this increase was on the "as bid" basis above the $250 cap (see light blue section of the above chart) allowed by Amendment 33. As shown in the following charts, out-of-market purchases were reduced by more than 50% in the week following Amendment 33. Many out-of-market purchases were replaced by reliance on supplies offered on an "as bid" basis into the ISO market. As gas prices dropped below $20 in mid-December, an increasing amount of real time energy needs were met by supplies offered at or below the $250 level.

Daily Real Time Energy Costs (Beep and Out-of-market)
November 20 - December 31, 2000



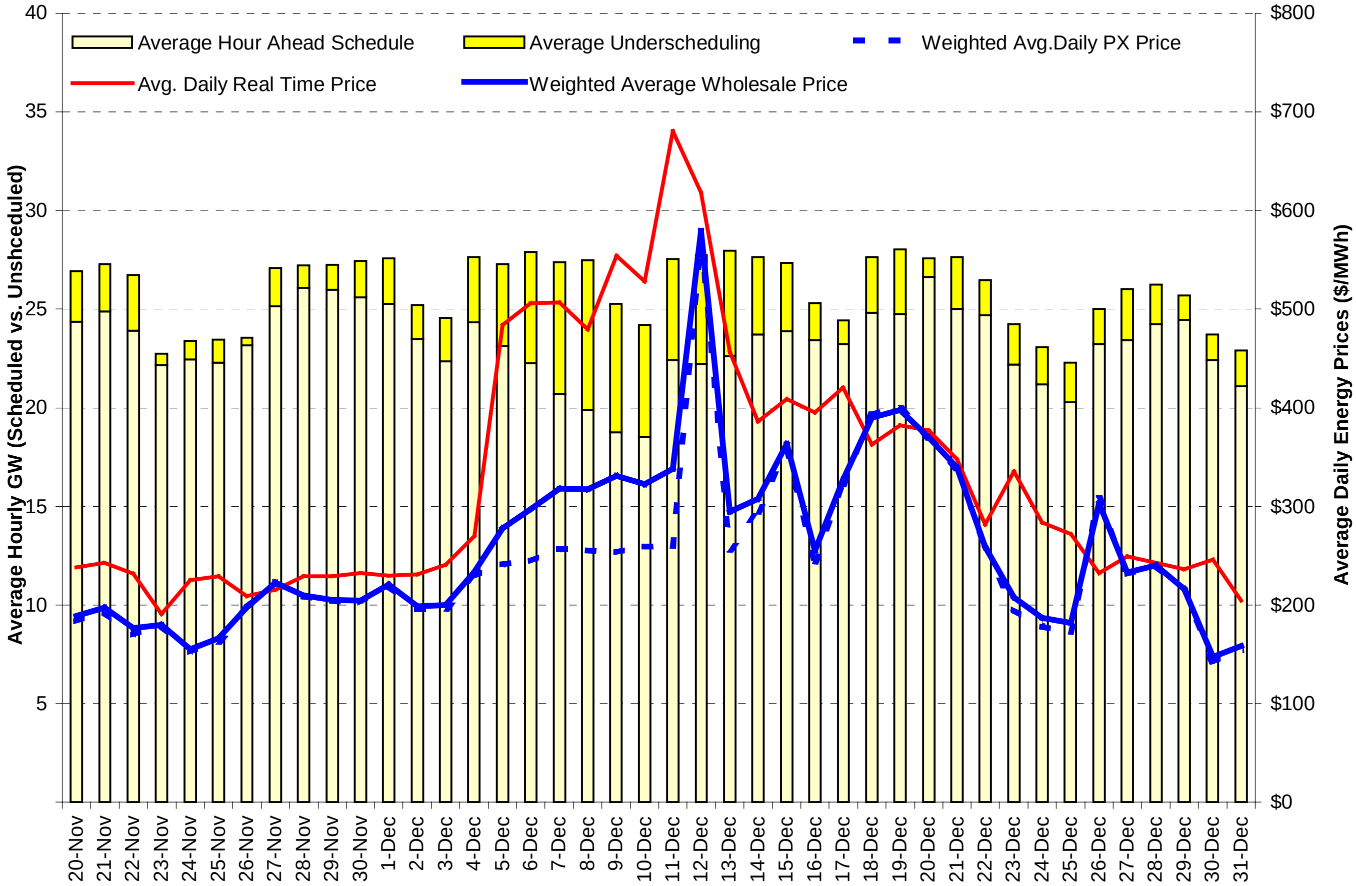
The above chart shows the trend of increasing real time energy costs and the correlation between these costs and the price of natural gas. Natural gas prices peaked on December 11th at about $60/MMBTU, or $720/MWh, and declined to around $12/MMBTU, or $144/MWh, toward the end of the month. After the peak, decreases in real time energy price lagged behind decreases in natural gas price leaving a wide margin between December 12th and the end of the month.

Average Daily Real Time Energy, PX Day Ahead, and Natural Gas Prices



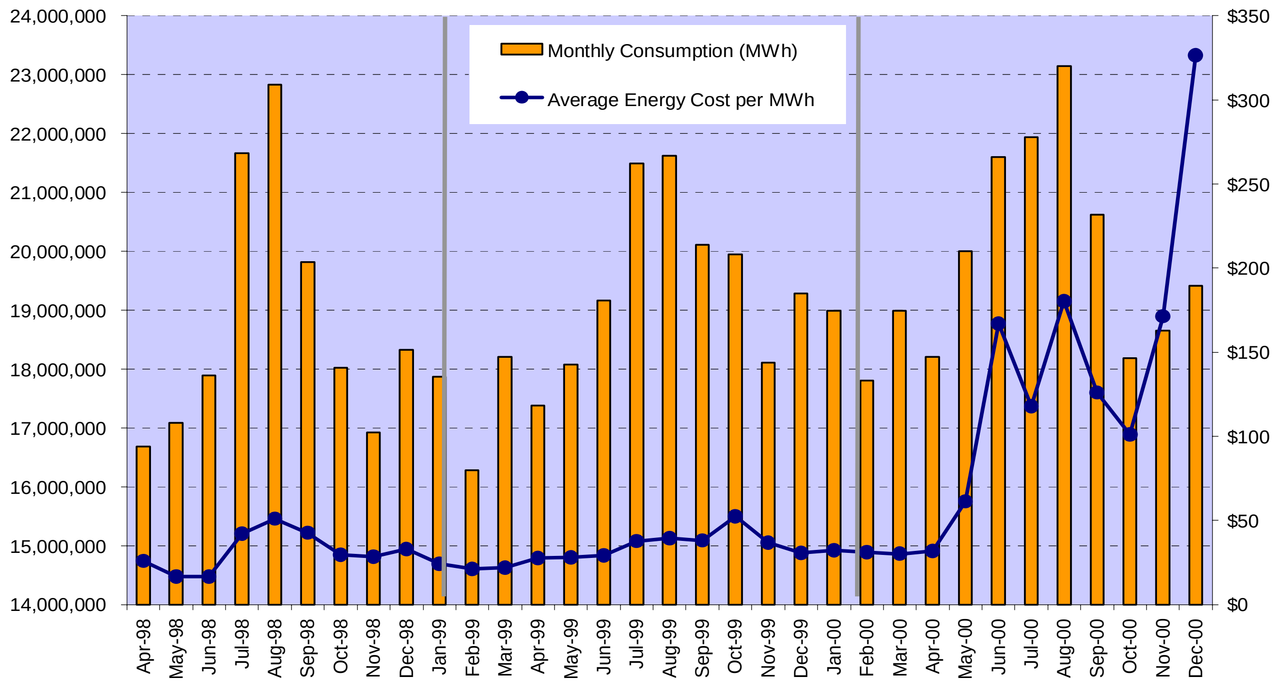
The chart above shows how real time energy prices in December have been driven primarily by the spike in natural gas prices. The overall average daily cost of real time energy rose above the $250 price cap starting on December 5th due to the high volume of out-of-market purchases and the fact that much of this energy was purchased at a price above the $250 real time market price cap. This represents the point at which price spiked from about $22 to $27/MBtu, making it uneconomic for many thermal plants to operate at a maximum price of $250.

Real Time Price, PX Price, Wholesale Price, and Underscheduling



The chart above summarizes average daily wholesale energy costs from late November through December 31, 2000. In addition to showing average daily real time and PX Day ahead prices, weighted average total wholesale energy cost is provided. Higher prices and price spikes are correlated with underscheduling.

Monthly Load and Price Trends (April 1998 to December 2000)



Total weighted average monthly wholesale cost of energy, with energy scheduled in Hour Ahead valued at PX Day Ahead market price, and unscheduled load (Actual ISO Load – Hour Ahead Scheduled Load) valued at real time price. This chart also includes cost of ancillary services. See detailed breakdown of costs on table on following page.

Monthly Energy and Ancillary Service Cost Summary*
April 1998 - December 2000

	ISO Load (MWh)	Estimated PX Energy Costs*	Estimated Bilateral Energy Costs*	ISO Real Time Energy Costs**	AS Costs***	Total Energy Costs	Total Costs (AS+ Energy)	Energy Cost per MWh	AS Costs- $ per MW Load	AS Costs as % of Energy Costs	Total Costs per MWh
Total 1998	169,239,273	$ 4,148,351,606	$ 555,818,791	$ 209,244,238	$ 637,675,596	$ 4,913,414,635	$ 5,551,090,231				
Avg 1998	18,804,364	$ 460,927,956	$ 61,757,643	$ 23,249,360	$ 70,852,844	$ 545,934,959	$ 616,787,803	$29.03	$3.77	13.0%	$32.80
Jan-99	17,872,700	$ 335,132,989	$ 55,068,344	$ 8,246,862	$ 31,306,115	$ 398,448,195	$ 429,754,310	$22.29	$1.75	7.9%	$24.05
Feb-99	16,279,026	$ 259,423,526	$ 51,461,102	$ 13,150,169	$ 18,613,312	$ 324,034,797	$ 342,648,109	$19.91	$1.14	5.7%	$21.05
Mar-99	18,204,684	$ 299,993,151	$ 59,846,165	$ 9,976,791	$ 27,410,591	$ 369,816,107	$ 397,226,698	$20.31	$1.51	7.4%	$21.82
Apr-99	17,376,548	$ 354,352,002	$ 75,504,436	$ 10,496,234	$ 36,536,548	$ 440,352,672	$ 476,889,220	$25.34	$2.10	8.3%	$27.44
May-99	18,077,394	$ 374,522,722	$ 73,660,130	$ 12,366,651	$ 42,791,624	$ 460,549,503	$ 503,341,127	$25.48	$2.37	9.3%	$27.84
Jun-99	19,162,916	$ 415,699,218	$ 86,582,032	$ 13,829,800	$ 43,250,399	$ 516,111,050	$ 559,361,449	$26.93	$2.26	8.4%	$29.19
Jul-99	21,485,058	$ 637,671,352	$ 89,287,935	$ 26,051,926	$ 55,820,804	$ 753,011,213	$ 808,832,017	$35.05	$2.60	7.4%	$37.65
Aug-99	21,622,092	$ 694,962,244	$ 86,563,208	$ 29,190,942	$ 39,973,755	$ 810,716,394	$ 850,690,149	$37.49	$1.85	4.9%	$39.34
Sep-99	20,109,514	$ 604,492,336	$ 101,524,767	$ 27,421,137	$ 30,508,194	$ 733,438,240	$ 763,946,434	$36.47	$1.52	4.2%	$37.99
Oct-99	19,951,312	$ 835,475,235	$ 147,303,235	$ 18,580,542	$ 45,489,561	$ 1,001,359,012	$ 1,046,848,573	$50.19	$2.28	4.5%	$52.47
Nov-99	18,107,488	$ 575,582,854	$ 63,457,796	$ 4,467,551	$ 21,603,658	$ 643,508,201	$ 665,111,859	$35.54	$1.19	3.4%	$36.73
Dec-99	19,284,096	$ 478,645,974	$ 91,767,455	$ 6,275,389	$ 10,569,152	$ 576,688,818	$ 587,257,970	$29.90	$0.55	1.8%	$30.45
Total 1999	227,532,828	$ 5,865,953,603	$ 982,026,605	$ 180,053,994	$ 403,873,712	$ 7,028,034,202	$ 7,431,907,914				
Avg 1999	18,961,069	$ 488,829,467	$ 81,835,550	$ 15,004,500	$ 33,656,143	$ 585,669,517	$ 619,325,660	$30.89	$1.78	5.7%	$32.66
Jan-00	18,983,780	$ 494,623,762	$ 103,137,341	$ 2,779,343	$ 11,840,681	$ 600,540,446	$ 612,381,127	$31.63	$0.62	2.0%	$32.26
Feb-00	17,807,124	$ 419,193,999	$ 102,697,069	$ 19,912,862	$ 10,410,734	$ 541,803,930	$ 552,214,664	$30.43	$0.58	1.9%	$31.01
Mar-00	18,989,348	$ 432,481,076	$ 89,947,932	$ 38,614,724	$ 11,433,021	$ 561,043,732	$ 572,476,753	$29.55	$0.60	2.0%	$30.15
Apr-00	18,211,768	$ 429,121,278	$ 100,655,760	$ 30,798,765	$ 17,292,474	$ 560,575,803	$ 577,868,277	$30.78	$0.95	3.1%	$31.73
May-00	19,997,490	$ 828,282,890	$ 224,651,908	$ 108,145,226	$ 63,157,857	$ 1,161,080,024	$ 1,224,237,881	$58.06	$3.16	5.4%	$61.22
Jun-00	21,604,584	$ 2,303,137,741	$ 529,029,059	$ 338,765,889	$ 436,096,819	$ 3,170,932,689	$ 3,607,029,508	$146.77	$20.19	13.8%	$166.96
Jul-00	21,934,668	$ 1,895,933,096	$ 346,461,117	$ 215,661,113	$ 125,258,696	$ 2,458,055,326	$ 2,583,314,022	$112.06	$5.71	5.1%	$117.77
Aug-00	23,141,258	$ 2,785,789,989	$ 584,988,042	$ 515,281,868	$ 281,779,234	$ 3,886,059,899	$ 4,167,839,133	$167.93	$12.18	7.3%	$180.10
Sep-00	20,620,316	$ 1,819,265,049	$ 389,043,732	$ 236,310,904	$ 152,315,651	$ 2,444,619,685	$ 2,596,935,336	$118.55	$7.39	6.2%	$125.94
Oct-00	19,364,568	$ 1,490,487,163	$ 379,319,571	$ 22,640,462	$ 57,206,328	$ 1,892,447,196	$ 1,949,653,524	$97.73	$2.95	3.0%	$100.68
Nov-00	18,656,342	$ 2,292,049,823	$ 401,905,908	$ 386,595,481	$ 114,441,532	$ 3,080,551,212	$ 3,194,992,744	$165.12	$6.13	3.7%	$171.26
Dec-00	19,412,015	$ 3,741,655,601	$ 819,896,223	$1,333,046,100	$ 439,757,613	$ 5,894,597,924	$ 6,334,355,537	$303.66	$22.65	7.5%	$326.31
Total 2000	238,723,261	18,932,021,467	4,071,733,662	3,248,552,736	1,720,990,642	26,252,307,865	27,973,298,507				
Avg 2000	19,893,605	1,577,668,456	339,311,139	270,712,728	143,415,887	2,187,692,322	2,331,108,209	$109.97	$7.21	6.6%	$117.18

PX Energy Cost estimates include UDC owned supply sold in the PX. Bilateral Energy Cost estimates based on difference between hour ahead schedules and PX quantities.

* Beginning November 2000, ISO Real Time Energy Costs include OOM Costs.

** AS costs include self-provided quantities

NOTE: The total weighted average monthly wholesale cost of energy is calculated using energy scheduled in Hour Ahead valued at PX Day Ahead market price, and unscheduled load (Actual ISO Load – Hour Ahead Scheduled Load) valued at real time price. This table also includes cost of ancillary services. It is important to note these costs do not reflect net market costs because we estimate that about 50% of total market costs are "hedged" by utility-owned generation, existing supply contracts (QFs, etc.), and forward hedging contracts and thus not netted out of these reported costs.