CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers, ISO Board Assistants

Date: February 1, 2002

Re: Market Analysis Report for November 2001

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

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

EXECUTIVE SUMMARY

Real-time electricity and ancillary service prices increased in November from the levels seen in October, as seasonal maintenance outages constrained supply. However, market activity and prices remained light compared with levels seen earlier in 2001, due primarily to low natural gas prices, weak demand, and service of load by forward contracts. Overall, the average wholesale price of real-time incremental electricity increased to approximately $48 in November, from approximately $42 per megawatt-hour (MWh) in October. The real-time price of decremental electricity decreased to approximately $9/MWh, from $10/MWh in October.[1] The increase in incremental real-time energy prices had little cost impact on wholesale energy costs, as real-time volumes remain low. Total estimated energy and ancillary service costs decreased to $45/MWh from $46/MWh in October. Loads have generally been moderate, averaging 24,593 MW. The California Energy Commission (CEC) reports that total energy consumption has declined 4.8% compared to November 2000, after normalizing for growth and weather conditions. The Department of Market Analysis (DMA) has observed real-time prices above competitive benchmark levels in November. Price mitigation ordered by the Federal Energy Regulatory Commission (FERC) continues to constrain prices for energy procured through the ISO's Balancing Energy Ex-Post Price (BEEP) auction market.

Scheduling coordinators have continued to rely on self-provision of Ancillary Services (A/S) in recent months. A/S costs, as a percentage of total energy costs, have leveled off below 2 percent in October and November. Interzonal congestion costs jumped substantially in November to levels not seen since February 2001, due primarily to the simultaneous derates of two key paths into Southern California. Many generators, including a large nuclear unit in Southern California, have gone off-line for scheduled maintenance, resulting in an increase in outage levels during the shoulder season.

FERC released Orders on November 7 and 20, 2001, that direct the ISO to enforce its creditworthiness requirement and to treat the Department of Water Resources' California Energy Resources Scheduling Division (CERS) as it treats scheduling coordinators (SCs). In response to these Orders, CERS is no longer making OOM purchases.

[1] As of the September 2001 report, the DMA has been reporting separate real-time incremental and decremental energy prices. The real time price is the average of the market clearing price and OOM purchase costs. See Table 1 under the California Wholesale Markets section for a further breakdown.

KEY MARKET CONDITIONS FOR NOVEMBER 2001

I. California Wholesale Energy Markets

- **Loads.** Loads in November 2001 were lower than those in November 2000, due primarily to mild weather, continued conservation efforts by consumers, and a softening economy. Monthly system energy consumption for November totaled 17,707 gigawatt-hours (GWh), a 5.1% decrease from November 2000. The peak load for the month reached 31,867 megawatts (MW), a 4% decrease from the November 2000 peak of 33,180 MW. Daily peak loads averaged 29,558 MW, a 4.4% decrease from November 2000.

  The California Energy Commission (CEC) provides estimates of conservation after normalizing for growth and weather conditions. In November, the CEC calculated that monthly peak demand for electricity decreased by 4.9 percent from November 2000, and total monthly electricity use dropped by 4.8 percent over the same period.

  Wholesale Energy Prices. The FERC's price mitigation order of June 19 continued to be in effect in November, imposing a soft price cap of $91.87/MWh on wholesale power markets in the Western United States. The BEEP market-clearing price (MCP) exceeded $91/MWh in 383 of the 4,320 ten-minute intervals in November in the NP15 region..[2]

  The ISO Department of Market Analysis (DMA) monitors several key price and volume statistics related to the real-time market. The real-time market now consists of several components, displayed in numbered columns in the table below, numbered as follows: (1) the MCP and quantities for incremental and decremental BEEP energy procured under the price cap; and (2) the incremental and decremental out-of-market (OOM) procurements scheduled in real-time. The combination of these components yields (3) the total overall average real-time prices. CERS real-time procurements on behalf of the IOU's comprise the bulk of the OOM activity. No energy was procured in the BEEP market as-bid above the price cap in November. The averages for each of these segments of total real time purchases for peak, off-peak, and all hours are shown.

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[2] On June 19, 2001, the FERC's West-wide price mitigation Order went into effect, initially capping real-time energy and ancillary services prices at $91.87/MWh throughout the WSCC during all California ISO non-emergency hours. (This mitigation scheme was altered in multiple Orders issued concurrently on December 19, 2001; please see the Market Analysis Report for December 2001 for details.) The June 19 Order caps prices at a formula-determined proxy price. During declared stage emergencies, the cap is determined by calculating the marginal cost of the highest priced unit dispatched. During non-emergency hours, the cap is set at 85 percent of the highest hourly ex-post price calculated during the last full hour of ISO operation under a Stage 1 emergency (which, at present, was $108.08/MWh and occurred in hour ending 10:00 on May 31, 2001). The cap has remained unchanged since the Order went into effect, because the ISO has not operated under a Stage 1 emergency for a full hour since that time. The cap will be reset upon the next full hour of a Stage 1 emergency. Bids accepted above the cap are paid as bid subject to cost justification; however, no generator has yet sufficiently justified bids above the cap. FERC also ordered a 10 percent adder to the market-clearing price for generators selling into the ISO markets to account for increased credit risk. Bids in the ISO's BEEP auction market accepted above the price cap are not paid the additional 10 percent credit risk premium adder.

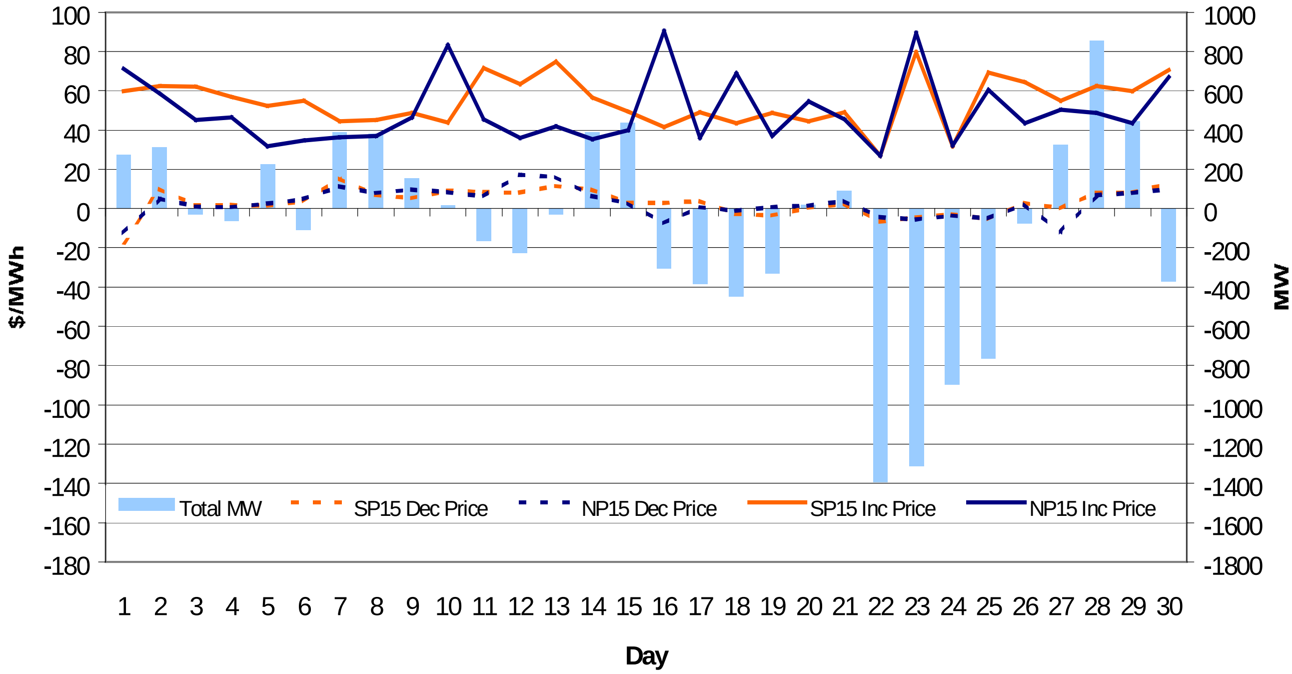
Table 1: Real Time Energy Price Summary for November 2001[3]

	Avg. Market-Clearing BEEP Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Under-scheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 63.71 89 GWh	$ 9.93 95 GWh	$ 36.17 112 GWh	$ 12.18 86 GWh	$ 48.35 200 GWh	$ 11.00 181 GWh	26,649 MW -0.7%
Off-Peak	$ 60.20 32 GWh	$ 3.63 58 GWh	$ 36.85 29 GWh	$ 9.22 84 GWh	$ 49.23 61 GWh	$ 6.95 142 GWh	20,481 MW -4.0%
All Hours	$ 62.77 121 GWh	$ 7.55 152 GWh	$ 34.90 131 GWh	$ 10.72 170 GWh	$ 48.26 252 GWh	$ 9.22 323 GWh	24,593 MW -1.0%

Average real time INC energy prices increased approximately 17% between October and November, while DEC energy prices decreased approximately 10%. Average system load decreased to 24,593 MW from 25,645 MW. On average, scheduling coordinators refrained from underscheduling in November; however, DMA observed 1.0% overscheduling, compared with 1.5% overscheduling in October. Figure 1 shows the daily average real-time prices and quantities for incremental and decremental energy in November (monthly averages are noted in column (3) of Table 1 above).

[3] The values in Column (1) of Table 1 do not include the 10 percent risk premium adder that is paid to all sellers receiving the market-clearing price. Dollar figures are $/MWh and GWh figures are total volume. 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 and ancillary services for the entire system (including UDC generation at cost, bilateral transactions at hub prices, and real time costs) for the month of November is estimated at $45/MWh. DMA imputes the real-time price on exchange and recirculation energy OOM trades.

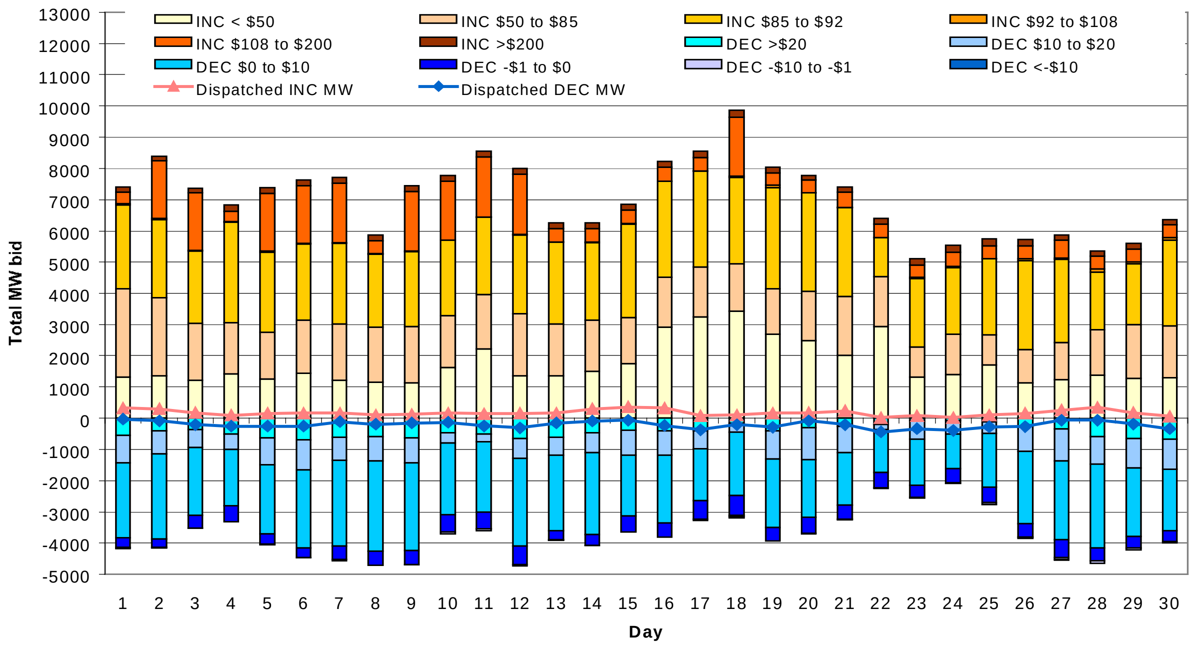
Figure 1: Daily Average Real-Time INC and DEC Energy Prices and Quantities - November 2001



The volume of energy transactions traded in the ISO's BEEP market continues to be minimal. Beginning in January, the Department of Water Resources' California Energy Resources Scheduling Division (CERS) entered into long-term and short-term purchases on behalf of utility distribution companies (UDCs) that have been sufficient to meet most of the UDCs' net-short load in November.

The soft demand situation has mitigated the ability of generators to exercise market power in the real-time markets. Most bids have been below the cap level, but generators continue to bid substantial portions of their energy near the $91.87 cap, and small portions above the cap. Figure 2 shows bids into the BEEP stack by price bin for November, with INC and DEC volume shown by MWh bid. Volume for INC bids in the range $85-$92 is depicted in orange.

Figure 2: Original Bids into BEEP Stack (Hourly Average by Day) – November 2001



The recent drop in natural gas prices has not been wholly reflected in real-time spot prices, which have risen since October, as noted previously. However, the volume of real-time energy procured in the ISO's control area in November was too low to calculate a meaningful estimate of the degree to which generators exercised market power. As noted, DMA has observed substantial BEEP procurements near the price cap, and will continue to report to FERC events that are indicative of the exercise of market power.

II. Ancillary Services Markets

Ancillary Service Prices

Ancillary services (A/S) are procured through day-ahead and hour-ahead markets to meet reserve requirements. Reserve requirements that are not met at prices at or below the soft cap are purchased at the bid price, and again are subject to just and reasonable cost review by the FERC. On December 15, 2000, FERC ordered the ISO to rescind capacity payments for Replacement Reserve services whenever energy is dispatched from the corresponding resource in real time. This has resulted in significant savings.

Scheduling coordinators (SCs) have been self-providing an increasing proportion of their A/S requirements. Table 5, below, shows the increase in SCs' self-provision of A/S.

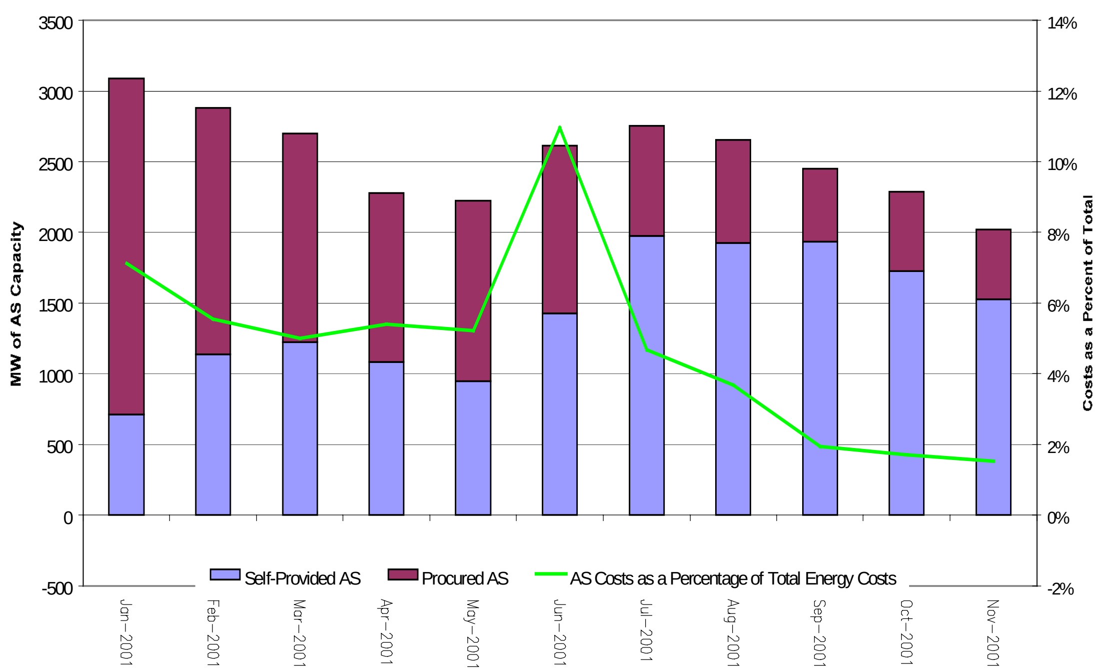
Changes in average prices for A/S were mixed between October and November. Upward and Downward Regulation prices both increased by approximately 8% in the day-ahead market to $12. Average prices for Spinning, Non-Spinning, and Replacement Reserves all remained under $3 in October and November. Between 66% and 96% of requirements were purchased in the day-ahead market. Table 2, shown below, summarizes the weighted average prices and quantities of A/S procured in November, in both the day-ahead and hour-ahead markets.

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – November 2001[5]

	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	$ 12	$ 24	$ 13	451	60	88%
Regulation Down	$ 12	$ 16	$ 13	434	76	85%
Spin	$ 2	$ 3	$ 2	939	41	96%
Non-Spin	*	$ 1	*	683	54	93%
Replacement	*	*	*	46	24	66%

Since January, SCs have increasingly self-provided A/S. Figure 3 shows the volume of A/S self-provided by SCs, compared with the volume procured through the ISO's A/S markets. The graph also shows explicit A/S procurement costs as a percentage of total energy costs (in green), which had declined since June 2001, and has stabilized below 2 percent since September.

Figure 3: Self-Provided and Procured Ancillary Services



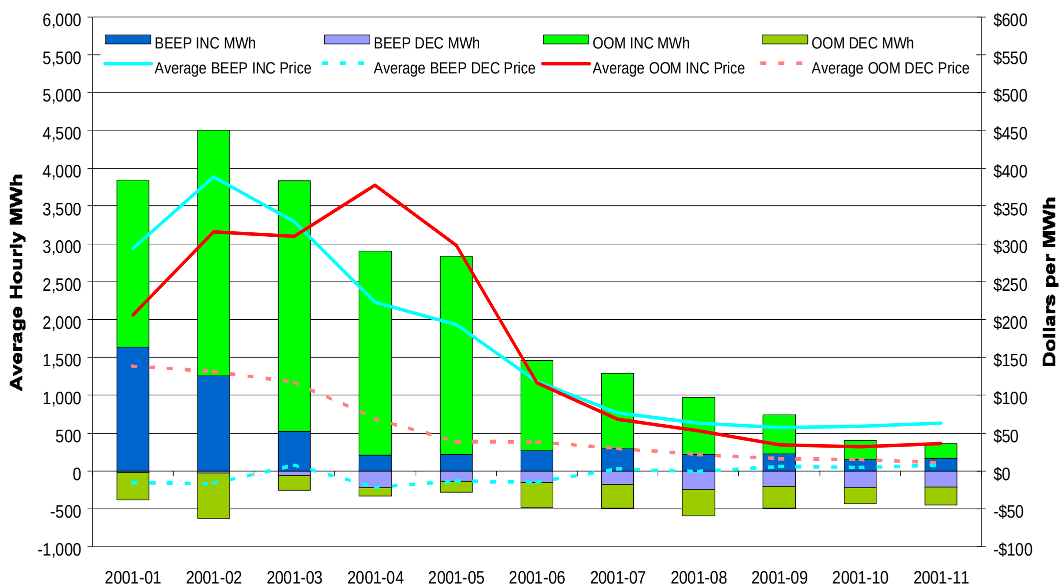
[5] Values in Table 2 and Table 3 do not include the 10 percent risk premium adder paid to all sellers receiving the market-clearing price. An asterisk (*) indicates a price below $1. Prices that vary between NP15 and SP15 are a result of quantity-weighting of identical prices, and do not indicate zonal procurement due to congestion.

III. Out of Market (OOM) Calls and BEEP Volumes

The average price for OOM INC energy was $36.31/MWh in November, an increase from October's average of $31.38/MWh. OOM DEC energy averaged $10.72 in November, a decrease from October's average of $15.10/MWh. On an hourly average basis, November INC and DEC OOM quantities were 195 MW and 237 MW, respectively. November saw the first OOM procurement (13 MWh) from generation within the ISO control area since August. DMA estimates the total costs of OOM purchases in October and November at approximately $3.58 million and $3.3 million, respectively.[7]

Hourly OOM INC and DEC volume and prices are compared with corresponding BEEP statistics below in Figure 4.

Figure 4. Average Hourly of BEEP and Out-of-market Purchases INC and DEC Prices and Quantities for 2001



Ample energy in forward schedules, in addition to lower-than-expected loads from June through November, has resulted in decreased reliance on real-time energy to meet load. This trend began in June and has continued through November.

On November 7 and 20, 2001, FERC released Orders directing the ISO to treat CERS as it does scheduling coordinators. By early December, CERS, which had conducted the bulk of OOM operations since January, had ceased procuring energy through OOM transactions. OOM activity decreased substantially in December, and will be addressed in greater detail in the December Report.

[7] Total OOM costs are net INC and DEC costs. October cost statistic is updated from the previous report. In accordance with FERC Order of 11/7/2001, DMA will report separate INC and DEC OOM volumes as of this report.

IV. Summary of Market Costs

The total costs of energy and A/S amounted to approximately $796 million in November, down from $878 million in October. This is the sixth consecutive month in which the total costs of energy and A/S were below those in the same month in 2000. The average cost of energy and A/S decreased from $46/MWh (adjusted) in October to $45/MWh in November. Energy and A/S costs continue to be above those seen in the first two years of operation. Energy and A/S costs for the first nine months of ISO operation in 1998 totaled approximately $5.55 billion, and averaged $33/MWh. Total costs of energy and A/S in 1999 were comparable to 1998 at approximately $7.43 billion (for twelve months), with an average of $33/MWh as well. However, 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. For January through November 2001, total energy and A/S costs have exceeded $25.8 billion, with an average cost of $124/MWh of load served. This represents a significant cost increase over the first 11 months in 2000, in which energy and A/S costs totaled approximately $20.9 billion. The increase is due primarily to the extraordinary costs incurred between November 2000 and May 2001. This trend reversed in June, and prices for the summer and fall have been substantially lower than those in 2000. Table 4, on the following page, provides a summary of energy and A/S costs. The costs estimated in this table include estimates for utility generation, CERS purchases, and bilateral transactions to serve load within the ISO control area.

Table 4: Summary of Estimated Market Costs, January through November 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	$ 756	$ 247	$ 3,466	$ 3,713	$ 185	$ 13.15	7.1%	$ 198
FEB-01	16,503	14,876	$ 2,657	$ 917	$ 198	$ 3,574	$ 3,772	$ 217	$ 12.00	5.5%	$ 229
MAR-01	17,857	16,744	$ 2,736	$ 881	$ 181	$ 3,616	$ 3,797	$ 203	$ 10.14	5.0%	$ 213
APR-01	17,237	16,267	$ 2,537	$ 755	$ 178	$ 3,292	$ 3,471	$ 191	$ 10.34	5.4%	$ 201
MAY-01	19,651	18,351	$ 2,771	$ 601	$ 176	$ 3,372	$ 3,548	$ 172	$ 8.97	5.2%	$ 181
JUN-01	19,777	19,468	$ 1,598	$ 111	$ 187	$ 1,709	$ 1,896	$ 86	$ 9.48	11.0%	$ 96
JUL-01	20,976	20,599	$ 1,458	$ 54	$ 71	$ 1,513	$ 1,583	$ 72	$ 3.37	4.7%	$ 75
AUG-01	21,048	21,571	$ 1,329	$ 34	$ 50	$ 1,363	$ 1,414	$ 65	$ 2.38	3.7%	$ 67
SEP-01	19,562	19,562	$ 958	$ 19	$ 19	$ 977	$ 996	$ 50	$ 0.97	1.9%	$ 51
OCT-01	19,105	19,395	$ 854	$ 10	$ 15	$ 864	$ 878	$ 45	$ 0.77	1.7%	$ 46
NOV-01	17,707	18,028	$ 774	$ 10	$ 12	$ 784	$ 796	$ 44	$ 0.68	1.5%	$ 45
Total 2001	208,194	201,810	20,382	4,148	1,334	24,530	25,865				
Avg 2001	18,927	18,346	1,853	377	121	2,230	2,351	121	7	5.4%	$ 124

***** Sum of hour-ahead scheduled quantities

****** Includes UDC costs (estimated at costs of production), CDWR costs (after 8/2001, projections only), and other bilaterals estimated 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

V. Inter-zonal Congestion Management Markets

Congestion in November was limited primarily to day-ahead and hour-ahead imports on Cascade, COI, Mead, and Palo Verde; day-ahead and hour-ahead South-to-North activity on Paths 15 and 26; and small amounts of hour-ahead import activity on Eldorado and Sylmar-AC. Total congestion costs for November rose to approximately $17 million in November, from less than $1 million in October.

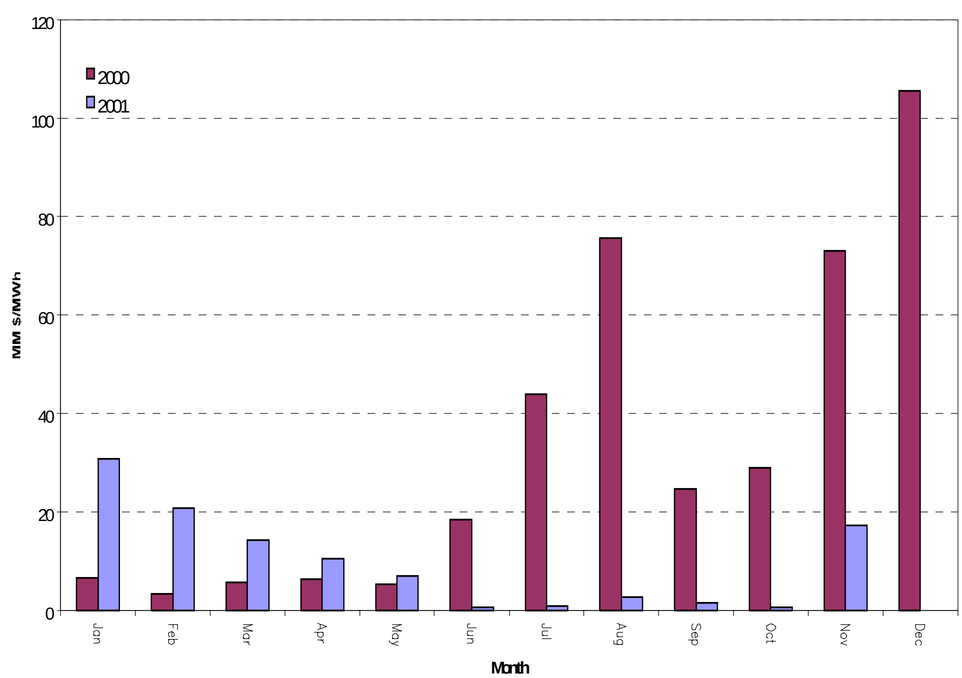
Import congestion on Palo Verde accounted for over $16.4 million of the total congestion costs in November, due in part to deratings. For several hours on November 13, Palo Verde was partially derated, while NOB simultaneously was derated completely, resulting in extreme congestion into Southern California. During these hours, congestion prices on Palo Verde reached approximately $200/MWh.

The following table summarizes the congestion rates and average congestion charges by branch group for the day-ahead market for November.

Table 5: Day-Ahead Congestion Summary for November

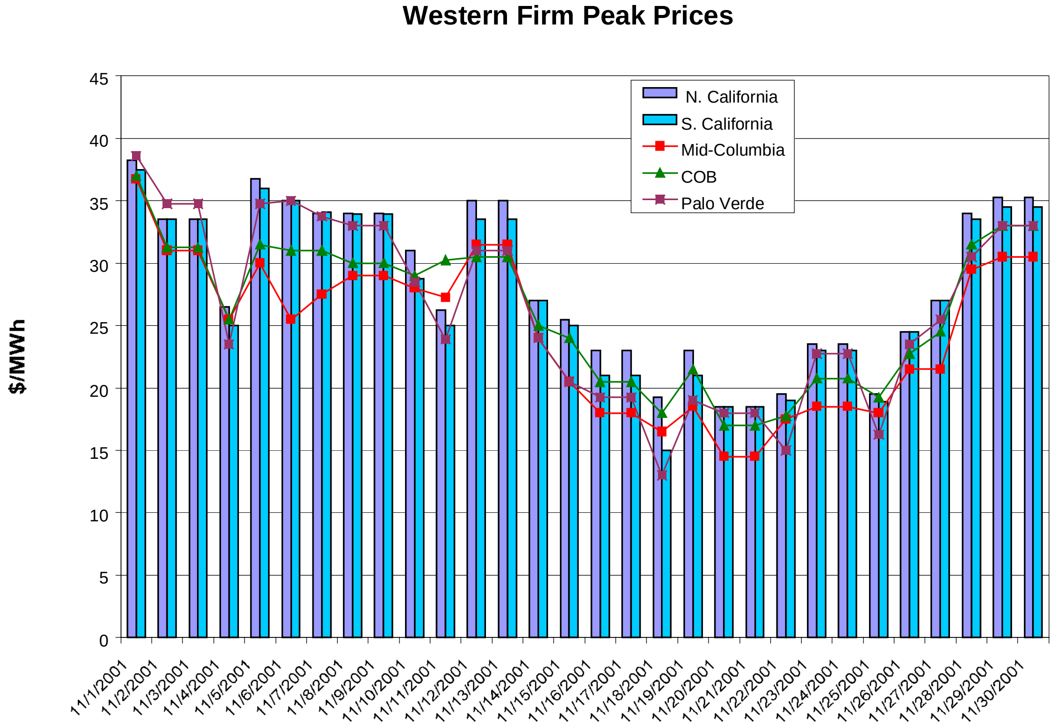
	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
Palo Verde (Import)	15.8%	35.0%	22.2%	$88.81	$57.94	$72.60
Path 15 (S-N)	0.8%	7.9%	3.2%	$0.02	$0.07	$0.06
Path 26 (S-N)	3.1%	13.75%	6.7%	$19.59	$62.55	$38.75

Figure 5: Comparison of Monthly Inter-zonal Congestion Costs



VI. Western Regional Market Prices

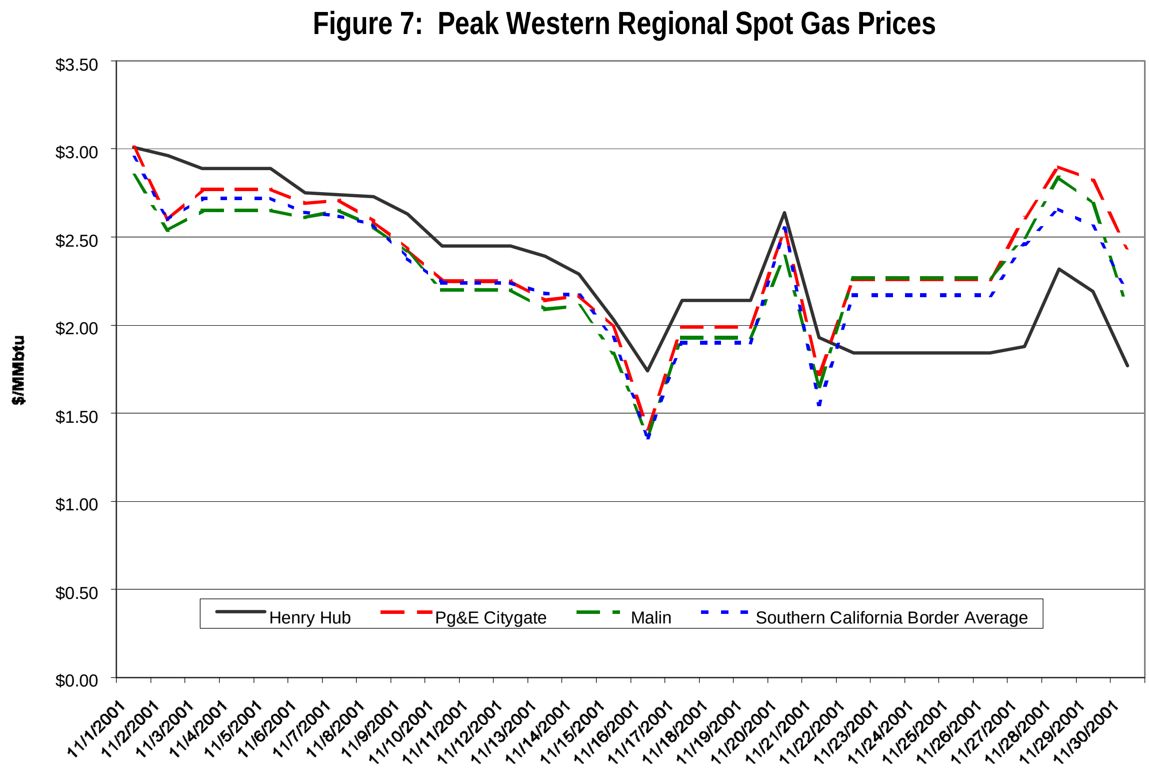
Figure 6: Western Regional Spot Electricity Prices[9]



While the volatility of western peak power prices increased slightly from October levels, both the volatility and the maximum of peak power prices remained low compared to the volatility and maximum prices of the past six months. With relatively mild temperatures, the resulting lower loads, lower natural gas spot prices, and generation units returning from offline status, power prices followed a downward trend from the beginning of the month, at around $37/MWh, through November 19, where prices dropped to between $12 and $19/MWh. During the latter third of the month, with higher spot gas prices and colder weather in the West, power prices followed an increasing trend. Prices increased between November 27 and 28, from $26 to $32/MWh, owing substantially to outages at two major coal-fired units in the Southwest. Prices for November ended between $30 and $33/MHw.

[9] Prices are peak hour, firm product prices as reported by Energy Market Report, published by Economic Insight, Inc.

California Natural Gas Prices



From a high of $3.00/MMbtu at the beginning of the month, natural gas prices steadily declined through the first half of November. Relatively mild temperatures and the lack of severe weather in the continental United States, along with nearly full reserves of natural gas, have resulted in a reduced demand for natural gas. Prices were further impacted by high-linepack operational flow orders[10] (OFOs) issued by PG&E and SoCalGas. Natural gas prices fell to a low of about $1.35/Mmbtu in mid November. The latter half of the month saw natural gas spot prices increasing once again; while temperatures throughout the state, particularly in the west, had fallen, the price increase was attributed more to the lack of California OFOs. There was some uncertainty in the markets relating to the Enron bankruptcy and the subsequent loss of liquidity in the gas markets due to the temporary suspension of trading on EnronOnline, from which it has not fully recovered. Between November 26 to November 30, gas prices spiked as winter storms hit parts of the West and the nation's midsection, peaking at between $2.60 and $2.90/MMbtu at California pricing points on November 28. By the end of the month, prices had returned to the $1.75 to $2.50/MMbtu range. Bid week prices for December were $2.27, $2.69, and $2.72 for SoCal Gas, Malin, and PG&E Citygate, respectively.

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[10] An operational flow order (OFO) is a mechanism to protect the integrity of natural gas pipelines in the event of high or low pipeline flow, and where storage assets cannot provide sufficient means to protect the pipelines from exceeding inventory limits.

VII. Performance of the Firm Transmission Rights (FTR) Market

FTR Concentration

There were no secondary FTR market trades and no FTR SC reassignments in November. Since there were also no trades or reassignments in August, September, and October, the concentrations listed in the July 2001 Market Analysis Report remain in effect.

FTR Scheduling

On most paths, FTRs have been used primarily for financial entitlements, to hedge against transmission usage charges. The relative volumes of schedules with FTR priority attached for November on all paths amounted to 17% of total available FTR volume (compared to 14% in October). The percentage was particularly high on some paths (e.g., 76% on Eldorado, 89% on Silver Peak, and 65% on IID-SCE, all in the import direction).

A metric of scheduling concentration is the maximum volume of MW scheduled by a single SC using FTRs, relative to the maximum total volume of MW scheduled using FTRs during the month. This ratio was high for Eldorado (82%), Silver Peak (100%), and IID-SCE (100%) in November. However, there was no day-ahead congestion on these paths in November, so relatively high levels of FTR scheduling should not be a reason for concern at this time.

The unusually high degree of import congestion on Palo Verde, noted above in this report, merits special attention. As noted, the frequency of day-ahead congestion on Palo Verde was 22.2%, with an average congestion charge of $72.60/MWh. The maximum volume of MW scheduled by a single SC, relative to the total MW scheduled using FTRs, over Palo Verde in the import direction, was 52%. This indicates that a single SC scheduled the bulk of the attached energy in November. Because two SCs control approximately 60 percent of total import FTRs on Palo Verde, a level that DMA regards as concentrated, DMA will continue to monitor congestion and FTR trading activity on this path, to determine whether the high congestion costs were due solely to network and system conditions, or are correlated to FTR concentration.

The following table shows the paths on which 1% or more of FTRs were attached to schedules, along with related statistics, for November.

Table 6: FTR Scheduling Statistics for November

	Import							Export	
IMPORT	COI	ELDORADO	IID-SCE	MEAD	PALOVRDE	SILVERPK	VICTVL	PALOVRDE	PATH26
MW FTR Auctioned	600	707	600	487	1,819	10	1,013	796	1727
Avg. MW FTR Sch.	129	540	391	37	685	9	19	20	50
% FTR Schedule	21%	76%	65%	8%	38%	89%	2%	2%	3%
Max MW FTR Sch.	400	707	439	157	1,160	10	84	200	291
Max Single SC FTR Schedule	200	582	439	125	600	10	47	200	291

VIII. Issues Under Review and Analysis

Must-Offer Requirements for Units with Long Start-up Times

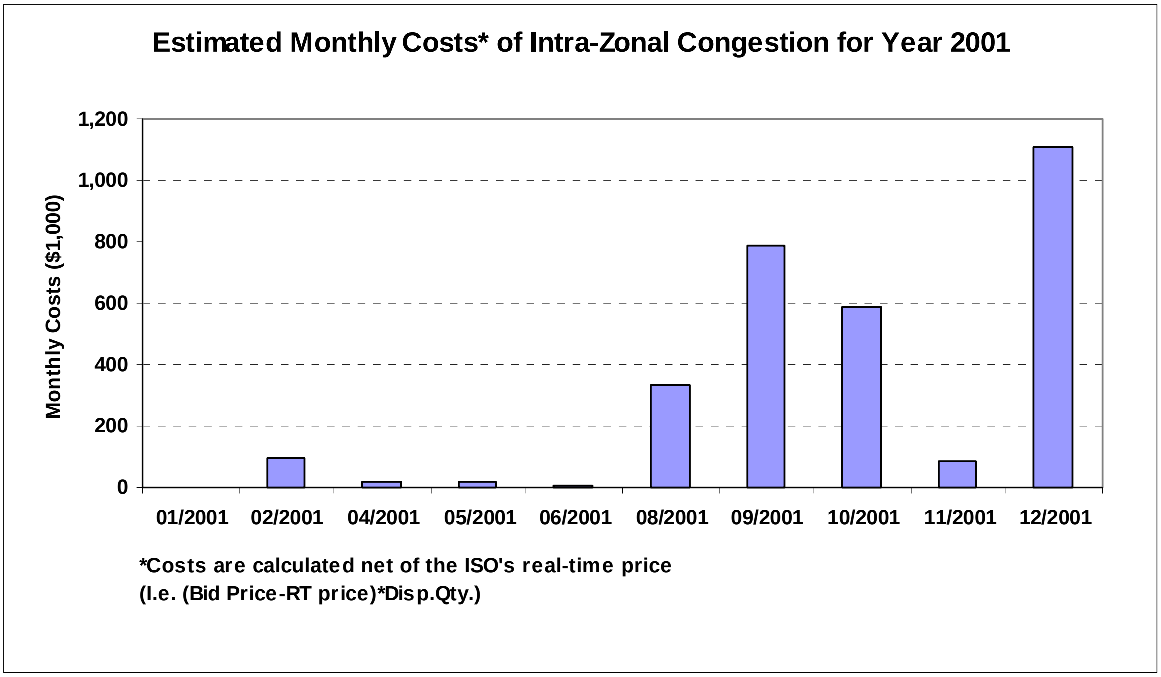
DMA is providing input to the ISO on a proposal to develop a must-offer waiver process that would provide for a more workable interpretation of the "must-offer" Tariff provision that originated from the FERC Orders of April 26 and June 19, 2001. The intent of this effort is to provide a process by which the ISO could commit units for reliability and market competitiveness on a Day-ahead basis, and to ensure that suppliers are reasonably able to recover their start-up, no-load, and variable production costs. Once this approach is finalized, the ISO will file it with FERC as an implementation update.

Intra-zonal Congestion Market Power Mitigation

Intra-zonal congestion refers to transmission congestion that occurs within a particular congestion zone. Inter-zonal congestion refers to congestion across congestion zones. Under the current ISO Tariff, these two types of congestion are mitigated differently.

Inter-zonal congestion is mitigated in the forward market through the ISO's Day-ahead and Hour-ahead congestion management markets. Because inter-zonal congestion spans large geographic regions, the ISO typically can call upon a large number of different Scheduling Coordinators to relieve the congestion. The ISO currently does not have a process for mitigating intra-zonal congestion in the forward market. The ISO mitigates intra-zonal congestion in real-time, and must face a limited number of resources capable of relieving the congestion constraint, due to the comparatively small geographic area. This difference can often give rise to local market power, in which a supplier, knowing the ISO will need to dispatch its units to relieve congestion, will submit either excessively high or low bids, depending on whether it is needed to increase or decrease generation, respectively.

During the Fall of 2001, the ISO experienced an increasing number of events indicative of localized market power associated with intra-zonal congestion. These situations have involved cases of the "DEC Game," and in some cases have been related to interconnections to new generators, in which the ISO has had to call on a limited number of suppliers to reduce scheduled output, and such suppliers submitted large negative decremental energy bids. This means that these suppliers are able to buy energy from the ISO to serve their forward energy obligations at a negative price; or, effectively, to get paid to withhold energy. DMA has been monitoring these incidents and has informed Market Participants engaged in this behavior that it views such bidding behavior as the exercise of market power and will be reporting these incidents to the FERC. In many cases, such discussions with suppliers have resulted in suppliers moderating their bidding behavior, but not to a level that DMA would deem to be acceptable. DMA has expressed these concerns to FERC Enforcement Staff and they have committed to contacting certain suppliers to discuss their bidding behavior. The following figure shows the costs of intra-zonal congestion by month:



At the November 29 Board of Governors Meeting, the ISO proposed and the Board approved an approach for mitigating bids in cases where local market power is being exercised. DMA is working with other Departments within the ISO to develop the Tariff modifications necessary to implement this change.

Real-time Market Design Issues

DMA is providing input to the ISO on a number of real-time market design issues. These include developing real-time economic dispatch as a long-term replacement for the target price approach and developing penalties for significant uninstructed deviations. Some of the major issues relating to penalties for uninstructed deviations concern whether the penalties should be assessed on a unit or portfolio basis, what constitutes "significant" (i.e. establishing tolerance thresholds), what is an appropriate penalty level (expressed as a percent of the MCP), and whether there should be special accommodations for certain unit types.

Market Design 2002

DMA is contributing to an ISO-wide effort to develop a comprehensive long-term market design proposal for the ISO markets. Some of the major design elements being considered include: an availability capacity requirement for load serving entities, a day-ahead unit commitment market, a day-ahead energy market, and a congestion management market that is based on a full network model (nodal pricing) instead of the ISO's existing zonal structure. DMA is providing input on the merits of each of these elements and reviewing them with Dr. Frank Wolak, Chairperson of the ISO Market Surveillance Committee.