CALIFORNIA ISO

Second Annual Report on Market Issues and Performance

April 1999 – December 2000

California Independent System Operator

November 2001

Summary Report on Market Issues and Performance, 1999 – 2000

1. Introduction

This report discusses the performance of markets managed by the California Independent System Operator (ISO) during the period April 1, 1999 to Oct 31, 2000.[1] The ISO market experienced dramatic change, going from stable performance in its second year of operation in 1999, to a state of near dysfunction by the summer of 2000. We identify and analyze in depth the fundamental reasons for this deterioration in market performance. Our review of market performance during this period enables us to draw insights into the changes that are necessary to promote competitive outcomes in California's electricity markets.

During 1998 and 1999, the first two years of ISO operation, wholesale prices of electricity in California's restructured markets averaged about $30 per megawatt-hour (MWh). This performance seemed to achieve the promise that industry restructuring would lower the state's high energy costs. Unfortunately, there was a rude awakening during the summer of 2000 (May through October), during which the market experienced dramatic jumps in spot prices. As this report explains, changes in both the structure of California deregulation and increased federal oversight of the ISO's markets were needed to address supply-demand imbalances, and the ability of suppliers to charge prices significantly above competitive levels.

Regulatory restrictions and the structural deficiencies of electric restructuring that contributed to poor market performance included:

- **Inadequate federal regulatory oversight of prices sellers could charge.** The ISO identified market power issues soon after the initial price spikes occurred in the summer of 1998. It had noted that sellers had market power that was inconsistent with the premise of just and reasonable rates. FERC had granted market-based rates using inadequate tests for determining whether sellers had market power.[2] Even after market power problems had been identified in the summer of 2000, the ISO Board lacked adequate authority to mitigate market power or sanction suppliers for market abuses.

- **Over-reliance on spot markets meant large volumes of wholesale power transacted in volatile real-time spot markets.** This created opportunities for sellers to "name their price" and charge prices significantly above competitive levels. If investor-owned utilities had contracted with sellers through long-term

[1] Although the body of the Report covers the period through October 31, 2000, the period covered in this Executive Summary is extended through December 31, 2000 to briefly address the market events which required subsequent market mitigation measures to be put in place by FERC.

[2] See First Annual Report on Market Issues and Performance, June 1999, Chapter 7.

contracts, there would have been fundamental changes in the incentives of sellers to profit from spiking prices in real time.

- **Tight supply relative to demand in the Western region.** No new regional additions in major generation facilities meant supply had not kept up with the high growth in demand throughout the West. When there was a sudden reduction in the amount of hydroelectric power in summer 2000 due to dry weather, and excessive outages of thermal generating facilities, it created an opportunity for suppliers to raise prices. Increases in spot natural gas prices and NOx emission trading credit prices helped fuel the increased cost of thermal generation. Market power problems in these input prices were magnified into even higher electric prices.

- **A retail rate freeze resulted in a lack of price sensitive demand to contain high prices.** Customers were insulated from the real-time cost of supplying power. There was no incentive for consumers to conserve energy or choose alternative suppliers as their power consumption costs were protected by frozen retail rates. This also resulted in no incentives to install technology that would enable consumers to respond to market price signals.

As a result of the events of summer 2000, several parties have argued vigorously that the California market is misconceived or irreparably broken and should be overhauled or even abandoned. We disagree. Rather, we believe that the preferred course of action is to address the identified market power problems directly, so that California consumers can realize the advantages of a competitive market structure. In this report we provide evidence that the California market worked well when there was sufficient competition, and we recommend changes that will increase competition in the future.

Given the stark contrast between second-year and summer 2000 market performance, the Department of Market Analysis (DMA) has divided this Second Annual Report on Market Issues and Performance into two major parts covering these two periods. Section 2 of the executive summary provides an overview of market performance during the second year of ISO operation. Section 3 provides an overview of the period May through October 2000, referred to as “Summer 2000.” Lastly, Section 4 describes the major market issues that have arisen throughout the entire time period and the solutions that we propose. This executive summary provides an overview of market performance sufficient for most readers.

A technical appendix to this report is organized into six chapters and provides greater detail on each of the markets operated by the ISO. Chapter 1 of the *Technical Appendix* provides an overview of the California ISO market structure, a time-line and description of key events and changes over the last two years, and a brief comparison of the California market design to the other ISOs operating in the United States. Chapters 2 through 5 provide reviews of second-year performance (April 1999 – March 2000) in each of the ISO’s major market areas: ancillary services, real-time imbalance energy, congestion management, and local reliability. Finally, Chapter 6 details the performance of the ISO markets in the period May through October 2000 and provides an analysis of the significant exercise of market power in the ISO markets.

2. Summary of Second Year Market Performance[3]

2.1 Overview of Market Performance

Restructured California energy markets, including the Power Exchange (PX) and the ISO, performed well in the second year of operation (April 1999 through March 2000). Moderate weather and sufficient imports resulted in a competitive electricity market in most hours of the year. Figure 1 shows monthly loads and average energy costs of meeting that load from the start of the market to December 2000. The average price of electricity rose from $29/MWh in 1998 to $31/MWh in 1999. In 2000, tight supply conditions and the exercise of market power resulted in substantial price increases. Wholesale prices, exclusive of ancillary services, rose to a high of $147/MWh in June 2000, a 350 percent increase over 1999 levels. These higher prices prevailed throughout the rest of 2000.

Table 1 presents monthly PX and ISO market statistics on wholesale expenditure of serving load, including energy and ancillary services. Yearly total expenditures increased from $7.4 billion in 1999 to $27.1 billion for 2000. Expenditures for 1999 break down as follows: $5.8 billion for energy traded in the PX Day Ahead market, $982 million estimated for energy traded in bilateral transactions (valued at the PX price), $180 million for energy traded in ISO spot contracts, and $404 million for ancillary services. Expenditures for 2000 were: $18.8 billion for energy traded in the PX Day Ahead market, $4 billion estimated for energy traded in bilateral transactions, $2.9 billion for energy traded in the ISO spot contracts, and $1.7 billion for ancillary services.

[3] While this section mainly reports on the second year of ISO market operation (April 1999 to March 2000), it sometimes touches on summer 2000 experiences for completeness.

Figure 1. After Two Years of Moderate Prices, Dramatic Increases Occurred in May 2000
Trend in Monthly Loads and Energy Costs

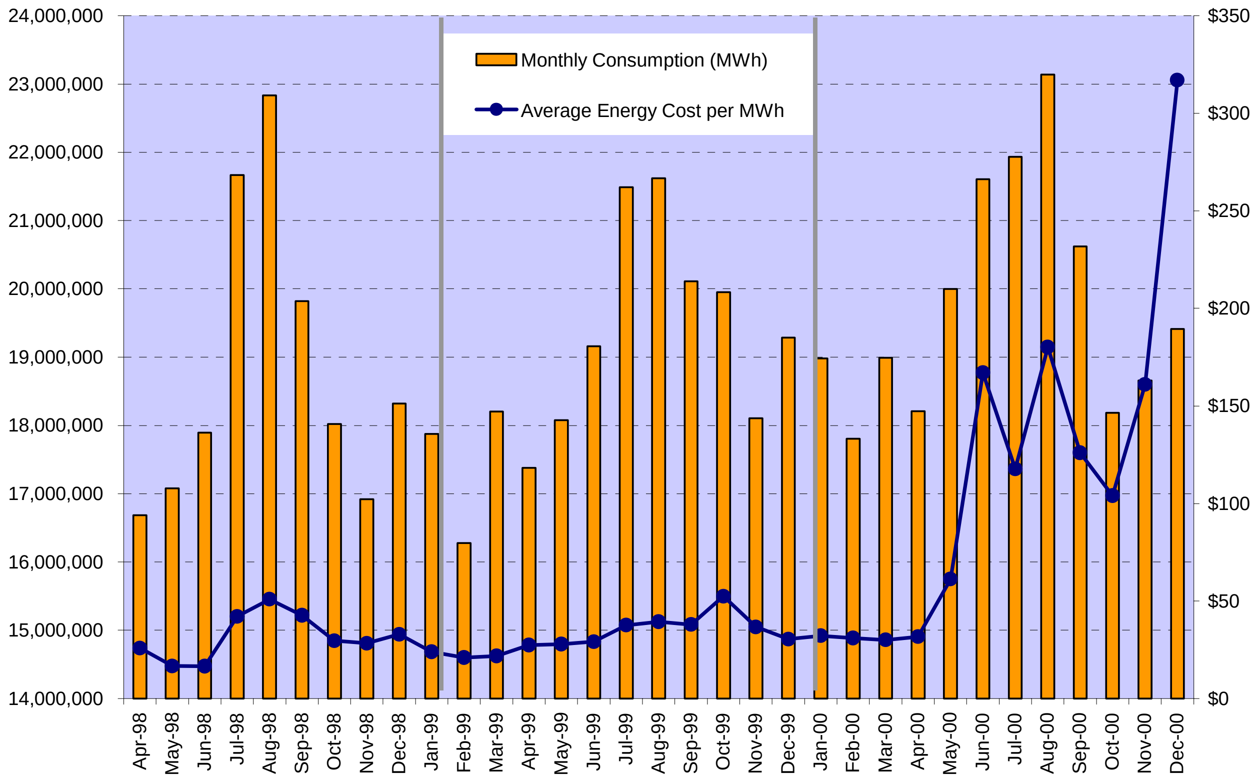

Table 1. Loads and Energy and Ancillary Service Expenditures (estimates in $ millions by month)

Cost Summary for PX and ISO (in $millions)

	ISO Load (GWh)	Estimated PX Energy Costs*	Est. Bilateral Energy Costs*	ISO Real Time Energy Costs**	AS Costs***	Total Energy Costs	Total Costs (AS + Energy)	Energy Cost per MWh ($/MWh)	AS Costs as % of Energy Costs	Total Costs per MWh ($/MWh)
Apr-98	16,686	$ 334	$ 23	$ 35	$ 41	$ 391	$ 432	$23	10.4%	$26
May-98	17,082	$ 184	$ 18	$ 20	$ 63	$ 222	$ 285	$13	28.6%	$17
Jun-98	17,894	$ 208	$ 22	$ 13	$ 53	$ 243	$ 296	$14	21.7%	$17
Jul-98	21,667	$ 682	$ 82	$ 35	$ 112	$ 800	$ 912	$37	14.0%	$42
Aug-98	22,834	$ 835	$ 136	$ 52	$ 141	$ 1,023	$ 1,164	$45	13.8%	$51
Sep-98	19,819	$ 626	$ 99	$ 33	$ 87	$ 759	$ 845	$38	11.4%	$43
Oct-98	18,020	$ 420	$ 60	$ 5	$ 49	$ 485	$ 534	$27	10.0%	$30
Nov-98	16,919	$ 387	$ 51	$ 4	$ 38	$ 442	$ 480	$26	8.6%	$28
Dec-98	18,320	$ 471	$ 64	$ 13	$ 55	$ 549	$ 603	$30	10.0%	$33
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Total 1998	169,239	$ 4,148	$ 556	$ 209	$ 638	$ 4,913	$ 5,551			
Avg 1998	18,804	$ 461	$ 62	$ 23	$ 71	$ 546	$ 617	$29	13.0%	$33
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Jan-99	17,873	$ 335	$ 55	$ 8	$ 31	$ 398	$ 430	$22	7.9%	$24
Feb-99	16,279	$ 259	$ 51	$ 13	$ 19	$ 324	$ 343	$20	5.7%	$21
Mar-99	18,205	$ 300	$ 60	$ 10	$ 27	$ 370	$ 397	$20	7.4%	$22
Apr-99	17,377	$ 354	$ 76	$ 10	$ 37	$ 440	$ 477	$25	8.3%	$27
May-99	18,077	$ 375	$ 74	$ 12	$ 43	$ 461	$ 503	$25	9.3%	$28
Jun-99	19,163	$ 416	$ 87	$ 14	$ 43	$ 516	$ 559	$27	8.4%	$29
Jul-99	21,485	$ 638	$ 89	$ 26	$ 56	$ 753	$ 809	$35	7.4%	$38
Aug-99	21,622	$ 695	$ 87	$ 29	$ 40	$ 811	$ 851	$37	4.9%	$39
Sep-99	20,110	$ 604	$ 102	$ 27	$ 31	$ 733	$ 764	$36	4.2%	$38
Oct-99	19,951	$ 835	$ 147	$ 19	$ 45	$ 1,001	$ 1,047	$50	4.5%	$52
Nov-99	18,107	$ 576	$ 63	$ 4	$ 22	$ 644	$ 665	$36	3.4%	$37
Dec-99	19,284	$ 479	$ 92	$ 6	$ 11	$ 577	$ 587	$30	1.8%	$30
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Total 1999	227,533	$ 5,866	$ 982	$ 180	$ 404	$ 7,028	$ 7,432			
Avg 1999	18,961	$ 489	$ 82	$ 15	$ 34	$ 586	$ 619	$31	5.7%	$33
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Jan-00	18,984	$ 495	$ 103	$ 3	$ 12	$ 601	$ 612	$32	2.0%	$32
Feb-00	17,807	$ 419	$ 103	$ 20	$ 10	$ 542	$ 552	$30	1.9%	$31
Mar-00	18,989	$ 432	$ 90	$ 39	$ 11	$ 561	$ 572	$30	2.0%	$30
Apr-00	18,212	$ 429	$ 101	$ 31	$ 17	$ 561	$ 578	$31	3.1%	$32
May-00	19,997	$ 828	$ 225	$ 108	$ 63	$ 1,161	$ 1,224	$58	5.4%	$61
Jun-00	21,605	$ 2,303	$ 529	$ 339	$ 436	$ 3,171	$ 3,607	$147	13.8%	$167
Jul-00	21,935	$ 1,896	$ 346	$ 216	$ 125	$ 2,458	$ 2,583	$112	5.1%	$118
Aug-00	23,141	$ 2,786	$ 585	$ 515	$ 282	$ 3,886	$ 4,168	$168	7.3%	$180
Sep-00	20,620	$ 1,819	$ 389	$ 236	$ 152	$ 2,445	$ 2,597	$119	6.2%	$126
Oct-00	18,184	$ 1,400	$ 356	$ 27	$ 56	$ 1,388	$ 1,434	$100	3.3%	$104
Nov-00	18,656	$ 2,292	$ 402	$ 195	$ 114	$ 2,889	$ 3,004	$155	4.0%	$161
Dec-00	19,412	$ 3,742	$ 820	$ 1,149	$ 440	$ 5,711	$ 6,151	$294	7.7%	$317
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Total 2000	237,543	18,842	4,048	2,877	1,720	25,373	27,083			
Avg 2000	19,795	1,570	337	240	143	2,114	2,257	$107	6.8%	$114

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

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

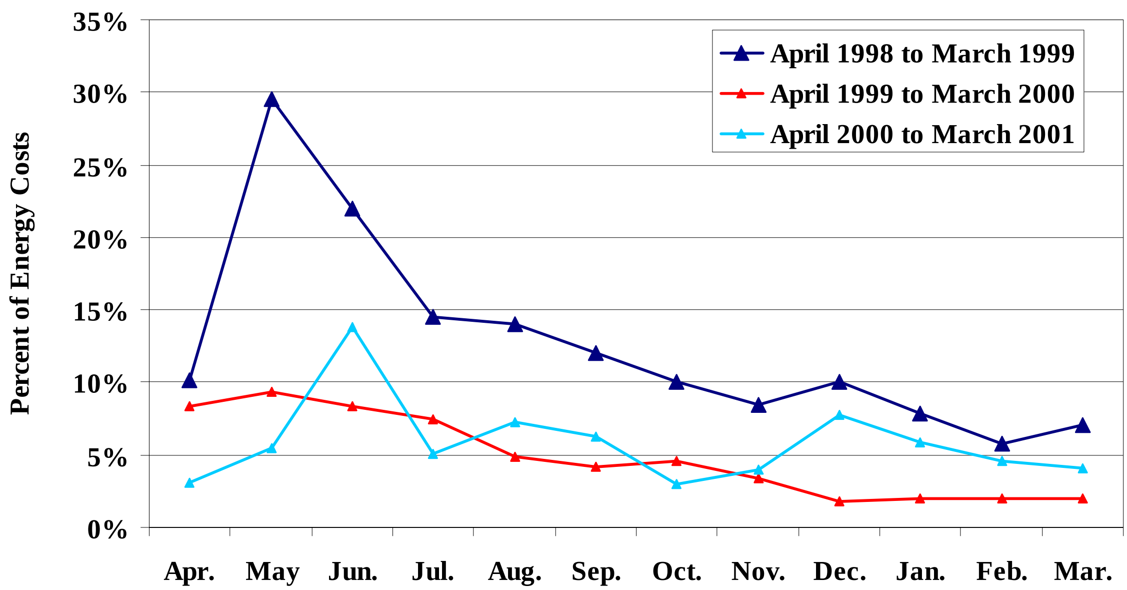
2.2 Ancillary Services Markets

Reserves for maintaining reliability on the power grid, known as **ancillary services** (AS), are either self-provided by market participants or traded in auctions at the ISO. The purchase of AS provides reserve generation capacity for contingencies on the grid. The California market was the first to demonstrate that these services can be acquired through a market mechanism.

The performance of the AS markets improved substantially in 1999 and 2000, due in large part to changes in market design implemented by the ISO. The AS markets functioned in an efficient, competitive manner for the large majority of delivery hours. In contrast to the first year, most price volatility and price spikes in the AS markets could be traced to tight supply and high system load conditions rather than to market design problems.

Figure 2 shows the significant drop in AS expenditure in year 1999 and 2000. From April 1999 through March 2000 ("Year 2"), expenditure on ancillary services averaged about $1.54 per MWh of total system load served, or about 4.8 percent of total wholesale energy expenditure. This represented a drop of 50 percent from April 1998 through March 1999 ("Year 1"), when AS expenditure averaged about $3.09 per MWh of load served, or 12.2 percent of total wholesale energy expenditure. There was an increase in ancillary service costs in Year 3 that followed the increases in the energy markets. Proportionally, the purchase of regulation service, the most flexible and thus highest-value type of AS contract, continued to account for more than 70 percent of total AS expenditure during both years.

Figure 2. Comparison of Total Monthly Ancillary Services Expenditure During Three Years of Operation



The drop in AS expenditure is attributable to a variety of factors, including fewer hours of extremely high peak load, and, more importantly, ISO's several modifications in AS procurement practices. These are summarized as follows:

- **Decrease in the quantity of AS purchased.** The largest single factor driving the decrease in AS expenditure was a decrease in AS capacity purchases from 17 percent of total system load in Year 1 to 13 percent in Year 2.
- **Deferment of purchases from the day-ahead to the hour-ahead market**. This reduced day-ahead price spikes, better matched total AS purchases to actual load levels, and promoted competition by including resources that became available after closure of the day-ahead market. During Year 2, the ISO purchased nearly 16 percent of its AS needs in the hour-ahead market, compared with about seven percent in Year 1.
- **New software and rational buyer auction algorithms.** New software enabled the ISO to purchase upward and downward regulation reserves separately, improving efficiency. The ISO is also able to purchase AS more efficiently with its new Rational Buyer auction algorithm. This algorithm enables the ISO to substitute superior service types when available at lower prices.
- **Higher limits on imports of Spinning and Non-spinning reserves.** In June 1999, the import limit on Operating Reserves (Spin and Non-spin) was raised from 25 to 50 percent of the hourly requirement, which resulted in increased competition in these markets. From August through November 1999, imports accounted for more than 20 percent of total Spin, Non-spin and Replacement Reserves on average, compared to about 11 percent during the same months of 1998.
- **Selective system-wide procurement of AS under forward transmission congestion conditions.** The AS procurement protocols were revised to recognize and take advantage of situations where AS procured on a system-wide basis could potentially create counter-flows to relieve inter-zonal congestion if dispatched. Previously, whenever the forward market energy schedules (day-ahead or hour-ahead) resulted in transmission congestion, the requirements for each service were established on a zonal basis, and the procurement was carried out separately in each zone, resulting in higher AS costs.
- **Charging SCs for AS based on metered demand rather than on scheduled load.** The ISO began charging the cost of AS to SCs based on their metered load rather than their scheduled load. This change eliminated an incentive to underschedule load in order to avoid paying AS costs.
- **Deviation Replacement Reserve.** The ISO defined a "Deviation Replacement Reserve" requirement based on the difference between total scheduled load and the ISO's own load forecast. The cost of procuring this extra reserve is charged to SCs based on their underscheduled loads in each zone, with the idea of providing an added incentive for SCs to schedule load more accurately by allocating the cost impact of underscheduling to the responsible entities.[4]

[4] An unintended consequence of this policy (which penalized only load underscheduling) was that it provided incentives to the generators to partially withhold energy (physically or economically) from the forward market to collect both Replacement Reserve capacity and real-time energy payments. To

- **Elimination of capacity payments to sellers of AS capacity that generate without instruction.** Effective June 14, 1999, the ISO began to identify AS capacity that generated uninstructed and was unavailable for dispatch (to provide real-time energy if needed) and rescinded the capacity payment for the amount of AS capacity that was unavailable.[5]
- **Allowance of bilateral trades of AS among scheduling coordinators.** This feature facilitates self-provision of AS by allowing one SC to provide AS to meet another SC's AS requirement under a bilateral agreement. To date, few such trades have occurred. Since January 1, 2001, under the ISO's proposal to unbundle the grid management charge (GMC), SCs that self-provide AS have been able to avoid a portion of the GMC.

2.3 Imbalance Energy Market

Real-time energy prices in Year 2 were 27% higher than in Year 1. One of the major factors contributing to higher prices was the very rapid growth in demand California experienced between the first and second years of operation. On a non-weather adjusted basis, peak loads increased by 1.8 percent in Year 2, while total energy consumption increased 4.2 percent over Year 1. Besides the higher loads, other factors contributed to the increase in real-time prices. They included:

- **Divestiture of thermal plants changed the incentive of the new owners in supplying real-time energy.** During 1998 much of the thermal generation in California was still owned by the state's investor-owned utilities (IOUs). As net buyers, however, IOUs had an incentive to bid this capacity in the energy and ancillary service markets in order to keep costs low and to accelerate payment of their competitive transition charge (CTC). In 1999, most of these generating resources had been divested to new owners who had no similar incentive to bid defensively.
- **Reduced in-state hydro supplies** created greater reliance on in-state thermal units, notwithstanding generally higher hydro imports from the Pacific Northwest.
- **Increases in natural gas prices** beginning in the fall of 1999 and escalating substantively throughout the year in 2000. On average, daily natural gas spot prices, measured at PG&E Citygate, were 15 percent higher in Year 2 than in Year 1. In the third year, prices increased from $5/mmbtu to peak at $50/mmbtu in December 2000.

Other important findings relating to the second year of operation of the ISO's real-time market include:

- Greater underscheduling of load and generation when system load levels exceeded 38,000 MW, which led to larger energy transactions in the real-time

remedy this unintended consequence the ISO proposed, and the FERC ruled in its December 15, 2000 Order, that generators could collect either Replacement Reserve capacity or energy, but not both.

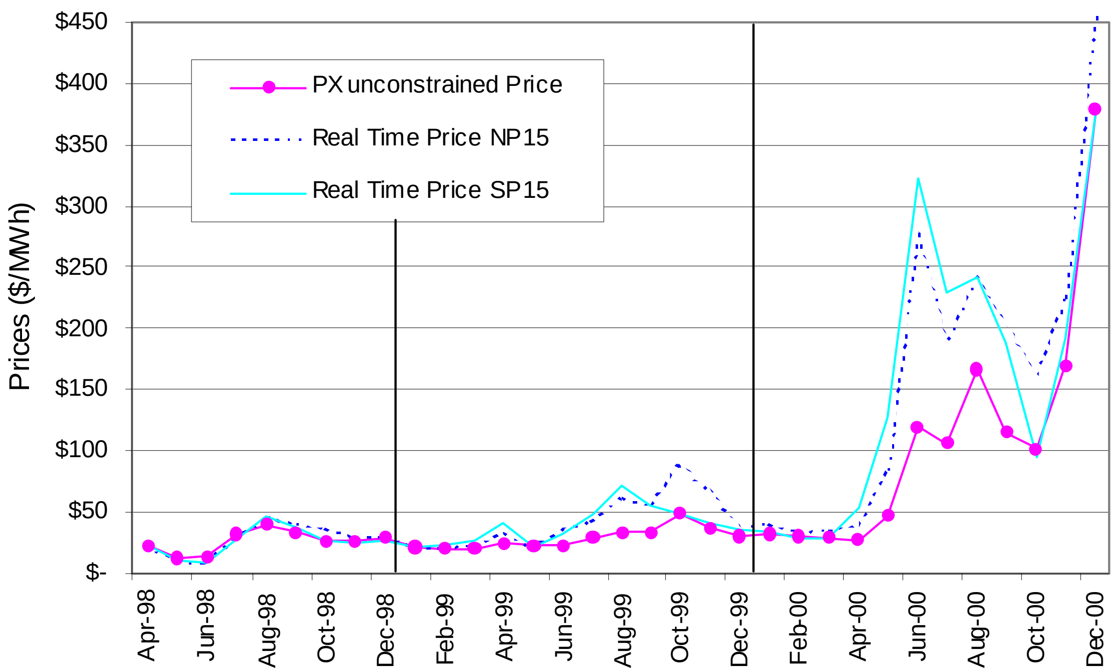
[5] The "no pay" provision was fully implemented in September 2000 with the implementation of 10-minute settlement and dispatch software. It eliminates not only the capacity payments to sellers of AS capacity that generate without instruction, but also the payment for the uninstructed energy generated from such capacity.

market. The underscheduling problem was less severe during the critical peak summer months of July and August, 1999.

- Greater supply was regularly bid into the real-time market in Year 2, particularly during the fall and winter months (October through March).
- Even though supply had increased, a greater percentage of the available supply was bid in at higher prices than in the first year of operation.
- Because of its availability and price, supplemental energy continued to be the dominant source of real-time imbalance energy dispatched by the ISO.

Figure 3 shows the dramatic increase in average monthly ISO real-time and PX day-ahead prices in 2000.

Figure 3. Average Monthly PX Forward and ISO Real-time Prices



2.4 Congestion Management Market

The ISO's congestion management market sets a price for the right to transmit electric power across or between zones on California's power grid during periods of congestion.

Review of the second-year performance of the ISO's zonal congestion management approach indicates that the inter-zonal congestion management market has worked well. Congested inter-zonal transmission interfaces have been allocated based on competitive bids, and observed levels of usage charges (the charges to SCs for using these interfaces) have reflected the underlying supply and demand conditions.

As in the first year, inter-zonal congestion occurred primarily on five interfaces or branch groups. Two of these branch groups – California Oregon Intertie and North Of Border – connect California to the Pacific Northwest; two others – Palo Verde and Eldorado – connect California to the Southwest; Path 15 connects the NP15 and SP15 zones within California. In Year 2 day-ahead inter-zonal congestion increased significantly on these branch groups. Path 15 congestion increased significantly in the south-to-north direction but decreased in the north-to-south direction.

There was no trend in Year 2 in the average level of usage charges for these branch groups when compared to Year 1. In some months, average usage charges were higher in Year 2, but in other months they were lower. However, on an annual basis, average usage charges were higher in Year 2 for COI (direction of import into California) and Path 15 (south-to-north direction).

Increases in day-ahead inter-zonal congestion can be attributed primarily to the following factors:

- **Statewide increase in annual energy consumption** of 4.2 percent.
- **Increased imports into northern California** compared to Year 1, due to reduced hydroelectric generation in northern California and improved hydroelectric conditions in the Pacific Northwest.
- **Increased supply in response to high prices.** According to some Northwest power traders, after seeing very attractive energy prices in Year 1 in California, they positioned themselves better to supply power to the California market in Year 2.
- **Divestiture of PG&E's northern California thermal generation** to independent power producers in Year 2 resulted in less energy from these resources being scheduled in the day-ahead market. When combined with California's reduced hydro production, this added to the increase in day-ahead import schedules from the south and higher south-to-north flows on Path 15.

An important milestone in the congestion markets in Year 2 was the establishment of auctions for firm transmission rights (FTR). An FTR allows its holder the right to transmit electric power across or between zones without being exposed to the fluctuation of the congestion cost. The market began operation on February 1, 2000. For more information, please refer to the DMA's report on the first nine months of operation of this market.[6]

In contrast to the generally efficient functioning of the inter-zonal market, the intra-zonal side of the market has been challenging for the ISO. In the second year of operation, two problems became apparent:

- **Intra-zonal congestion costs on some paths exceed the "commercially insignificant" threshold.**
- **Opportunities for market participants to exercise locational market power through strategic bidding of resources essential for relieving intra-zonal congestion**. Lack of workable competition within local areas allows market participants with strategically located resources to create intra-zonal congestion. These market participants can strategically raise prices if their unit is needed to

[6] ISO Department of Market Analysis, "The Firm Transmission Rights Market: Review of the First Nine Months of Operation, February 1 – October 31, 2000," November 30, 2000.

alleviate intra-zonal congestion, or by over-scheduling generation in the Day Ahead, and then bidding low or negative prices to decrease generation in real time (i.e., the "DEC game").

In the second year of operation, these problems were only partially resolved. The ISO first addressed this gaming by expanding the mix of bids eligible to resolve intra-zonal congestion competitively where possible (Amendment 18). This eliminated the gaming on Path 26.[7] The ISO also filed to pay prices after mitigating for locational market power when dispatching resources to meet local reliability in the absence of RMR resources.[8] FERC rejected this request and ordered the ISO to accept all bids even in cases where the bid was from only one supplier.[9] This FERC order allowed the DEC game to be continued on other paths.

The threshold for creation of new zones remains at a level when annual intra-zonal congestion cost exceeds five percent of the amount of the transmission access charge times the path rating. This threshold allows intra-zonal congestion management costs to cause the creation of additional zones so that any remaining intra-zonal congestion should be rare or commercially insignificant, except when market power is exercised.

The ISO continues to work toward a market redesign that will resolve intra-zonal congestion problems. Some of the challenges to be addressed are:

1. To create additional zones based on frequently congested intra-zonal pathways, so that all commercially significant congestion is priced and charged to users.
2. To develop market power mitigation procedures that enable the ISO to procure those resources that are essential for local reliability, without allowing suppliers to extract excessive payments for their services.

2.5 Local Area Reliability

Local reliability needs arise on an electric power network due to constraints in the transmission system. Reliability necessitates that resources be sited at specific locations on the grid to operate at specific levels, to ensure reliability under any given system conditions (load levels, path ratings, facility outages, etc.). The ownership of generating resources within transmission-constrained "local reliability areas" typically is highly concentrated, allowing the owners of resources needed for local reliability to exercise market power under a broad range of load and system conditions. California has adopted a contractual approach, known as Reliability Must Run (RMR), to ensure the availability of resources needed for local reliability service only. *These RMR contracts were not intended nor are sufficient to cover the number of owners that have locational market power.*

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[7] Subsequently, because of Path 26's commercial significance as reflected in continued intra-zonal congestion costs, it was converted to an inter-zonal interface to enable explicit pricing of transmission, effective February 1, 2000.

[8] No tools similar to those available in the NY ISO and PJM to mitigate bids for intra-zonal congestion were granted to the CAISO by FERC. The only means available were RMR contracts which were meant for local reliability purposes and were not widely available to mitigate locational market power.

[9] FERC Order January 2000.

The levels of RMR energy dispatched have varied with overall system load levels in a similar manner across both years of operation. Moreover, the share of RMR requirements scheduled in the day-ahead market increased significantly as system loads and market prices increased. At the same time, there was a constant amount of RMR that consistently did not appear in day-ahead schedules. At all load levels, roughly 500 MW of the RMR energy needs that are anticipated before the day-ahead market failed to appear in day-ahead schedules balanced against loads when left entirely to the discretion of the RMR owners. They appeared predictably in real time, requiring the ISO to decrement other scheduled generating resources. This fact and its consequences for the markets prompted the ISO to seek FERC's approval to pre-dispatch RMR and require it to be forward scheduled against load, a procedure that went into effect in June 2000.

Significant changes to the structure of RMR contracts went into effect during Year 2 as a result of the reform process that culminated in the partial settlement agreement of April 1999. These changes eliminated the adverse economic incentives that were embedded in the original RMR contracts. Specifically, the original RMR contracts contained incentives for RMR owners to withhold capacity from (or bid at extremely high prices into) the energy and ancillary services markets. In conjunction with the RMR settlement process, most RMR owners reached agreements with the ISO and the responsible utilities (who pay for RMR as part of their responsibility for maintaining transmission system reliability) on the levels of their fixed cost payments under the new contracts. Some owners, however, chose instead to litigate this issue at FERC, resulting in an Administrative Law Judge (ALJ) ruling, which reduced dramatically the size of the fixed costs payment. In this ruling the ALJ adopted the "incremental cost" approach to RMR contract payments that was developed and advocated by the ISO and the responsible utilities. A full discussion of RMR contract costs, the impact of the ALJ ruling, and the incremental cost approach appears in Chapter 5 of the Technical Appendix.

3. Summary of Summer 2000 Performance

This section provides a summary of the facts and main causes of high summer 2000 prices and helps to motivate the discussion of safeguards needed to ensure competitive markets. The full details of summer 2000 market performance and evaluation of market power issues are presented in Chapter 6 of the Technical Appendix.

3.1 Overview of Price Spikes and Principal Contributing Factors

California's electricity market was characterized by a number of regulatory features that exacerbated the vulnerability of consumers to high and volatile market spot prices.

- Sellers were granted market–based rate authority based on inadequate determination of whether they had market power. State regulation enhanced the ability of sellers to raise prices when the thermal generating plants of the investor-owned utilities (IOUs) were divested to suppliers without any contractual requirements on this capacity's availability to serve California's load at reasonable prices. Such requirements have been used successfully to mitigate market power of new generation owners in other regions where divestiture was part of the electric restructuring approach.

- There were slow changes to regulations governing the IOUs' requirement to rely almost exclusively on spot markets (from day-ahead to real-time) to meet their energy needs.[10] At the start of the market such regulations prohibited the IOUs from hedging price risk through forward contracts. Limited hedging was allowed through the PX by early 2000. Additional forward contracting was allowed by the CPUC in August 2000. However, there continued to be after-the-fact prudence reviews that hampered IOU long-term contracting.
- A retail rate freeze established by the California legislature effectively eliminated any incentive to allow loads to be responsive to hourly prices.[11] The lack of deregulation on the consumer side of the market further inhibited incentives for any party to invest in installation of the metering technology necessary for greater price responsiveness by consumers. Retail competition would have also created additional market power mitigation by motivating a host of suppliers to offer fixed price contracts to consumers, thereby diminishing the profitability of being in the real-time market and spiking prices.

In addition to the lack of fundamental structural safeguards, there were several supply factors that contributed to the events of summer 2000:

- Hydroelectric production, both in California and throughout the Pacific Northwest, were more scarce in 2000 than in 1999, thus reducing an important source of supply and competitive pressure into the California markets.
- Load growth throughout the western region, particularly in the Southwest, increased the demand for out-of-state power that California needed to import on high-load days. This compelled the IOUs to bid up prices to secure the energy they must deliver to their customers.
- Natural gas prices increased in both level and volatility, driving up the production cost of electricity.
- Increased outages of generation facilities, both planned and forced, contributed to the above factors, exacerbating the already tight supply conditions.

The combination of these factors provided suppliers with both the incentive and the opportunity to raise prices well above competitive levels in the ISO and PX markets during conditions of relatively tight supply. Federal regulators did little to address the demonstration of market power by suppliers.[12] Moreover, the regulatory mandate that

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[10] The investor-owned utilities have continued to serve roughly 85 percent of the load in their territories due to the lack of development of significant retail competition.

[11] The retail rate freeze was structured to allow stranded cost recovery. But it was a poor mechanism because it created a large disincentive to retail competition. A far superior method of collecting stranded costs would have been on a c/kWh basis on every bill. This would have guaranteed a fixed stranded cost recovery while allowing consumers to shop for other providers who could provide a variety of protections suited to the needs of many consumers. This method would have allowed for the development of price responsive demand and protection to consumers through fixed price contracts.

[12] The ISO and Market Surveillance Committee had filed numerous reports documenting the market power of suppliers in the California market. See August 10, 2000 DMA Report on California Energy Market Issues and Performance, May-June 2000.

all IOU load must be served in the spot markets implied that these high prices would apply to large volumes of energy sales, resulting in extremely high energy procurement costs to the IOUs. Beginning with the unexpected heat waves in May and June of 2000, these price spikes and high energy costs continued throughout the summer 2000 period.

There were some actions taken as the events of summer 2000 unfolded which sometimes had unintended side effects through the changes they induced in the bidding behavior of market participants. These issues are summarized briefly below and discussed in detail in Chapter 6 of the Technical Appendix.

- **Underscheduling of loads and generation.** Underscheduling occurs when market participants (primarily the IOUs) do not fully schedule their anticipated requirements in the ISO's day-ahead and hour-ahead markets, and the loads and generator output appear in real time. The result is that large quantities of energy are transacted in the ISO's real-time imbalance market. Underscheduling presents significant operational difficulties, as the real-time market was designed to handle the small quantity of load that cannot be predicted accurately in advance (i.e., at most five percent of total load). When large quantities are transacted in real time, where the primary objective of ISO operators must be system reliability, there are significant opportunities for several suppliers to be pivotal and to exact excessive prices for their supplies.
- **The ISO's Replacement Reserve procurement policy.** In response to growing quantities of energy being transacted in the real-time market, the ISO began to expand its purchases of Replacement Reserve to ensure adequate real-time capacity to meet system imbalances. The quantity of Replacement Reserve to be purchased was proportional to the gap between the ISO's load forecast and the amount of load scheduled in the forward markets. The cost of this capacity was to be allocated to SCs in proportion to their unscheduled metered load. Suppliers, however, soon realized that they could withhold supply from the forward markets (generally by bidding higher prices into the PX than the buyers were willing to pay), thereby exacerbating underscheduling and forcing the ISO to buy larger quantities of Replacement Reserve. This enabled suppliers to earn both a high capacity payment *and* a high real-time energy payment.

The ISO identified market power issues soon after the first price spike occurred in the spring of 1998.[13] In an August 1998 report, the ISO's Market Surveillance Committee first formally reported potential market power problems associated with the California electric markets. Since then, both the MSC and DMA have produced numerous reports and analyses identifying the need to mitigate market power in the ISO markets. Quick action in addressing the exercise of market power in the California markets could have substantially protected consumers from being exposed to the excessive costs that resulted from the exercise of market power.

[13] See "Preliminary Report on the Operation of the Ancillary Service Markets of the California Independent System Operator," August 19, 1998, Frank Wolak, Carl Shapiro, Robert Nordhaus.

3.2 Impacts of lowering price caps and studies of market power

Following the price spikes in May and June of summer 2000, the ISO Governing Board took immediate corrective action to contain prices. The only tool available to the ISO Board was the power to set price caps up to November 15, 2000. The ISO Governing Board took action to lower the price caps in the real-time energy market from $750/MWh to $500/MWh on July 1, 2000, and again to $250 on August 7, 2000. The same changes also applied to the ancillary services markets, with the exception of the Replacement Reserve market, whose cap was lowered to $100/MW as discussed in Chapter 6 of the Technical Appendix.

The average energy prices for three sample periods when different price caps were in effect (June, July 1-Aug 6, and Aug 7-Aug 31, 2000) were $147/MWh, $134/MWh, and $150/MWh, respectively. These results indicate that average energy prices were not significantly different during the period August 7-31 under a price cap of $250/MWh than they were in the previous periods under higher price caps. Since load in July was unusually moderate, the period August 7-31 can be more appropriately compared with that of June. For the period August 7-31, average hourly load was about 2% higher than average hourly load during June, and production costs to power producers were more than 10% above June levels.

In evaluating the impact of lowering price caps some have said that price caps may have actually increased prices. They point to the higher average prices in August than in June and July. We found that although there was a slight increase in prices compared to June, the price increase was much less after considering the substantial increases in production costs due to higher natural gas and emission trading prices.[14] A further analysis of average prices by peak and off-peak hours indicates that average prices in August were lower during the peak hours, due to the constraint of the lower price cap, but higher during off-peak hours when price caps tend not to be binding. Higher prices during off-peak hours may be explained partially by higher natural gas prices. Thus, while the lower price cap was effective during high load hours, the higher costs of production in August offset the effects of lowering price caps in other hours, with a net effect of little change in average costs of meeting load.

Without safeguards such as adequate price-responsive demand and ability for utilities to hedge price risk in place, power suppliers enjoyed opportunities to offer power at prices well above those they would face as price-taking competitive sellers. Moreover, the lack of adequate market power mitigation and large volumes of energy in spot transactions resulted in unusually high impact on expenditures for electricity during the summer 2000. Price spikes started with the unexpected heat wave in late May and June and continued through most of the summer.

In order to demonstrate the magnitude of market power being exercised in the California markets, the ISO's Department of Market Analysis (DMA) prepared two detailed studies of market power. They are provided as an attachment to Chapter 6 of the Technical Appendix. These studies were completed subsequent to the analysis conducted in Chapter 6 and were filed at FERC in support of the ISO's March 22, 2001 filing in response to FERC Staff's *Recommendations on Prospective Market Monitoring and Mitigation for the California Wholesale Market.* The purpose of these

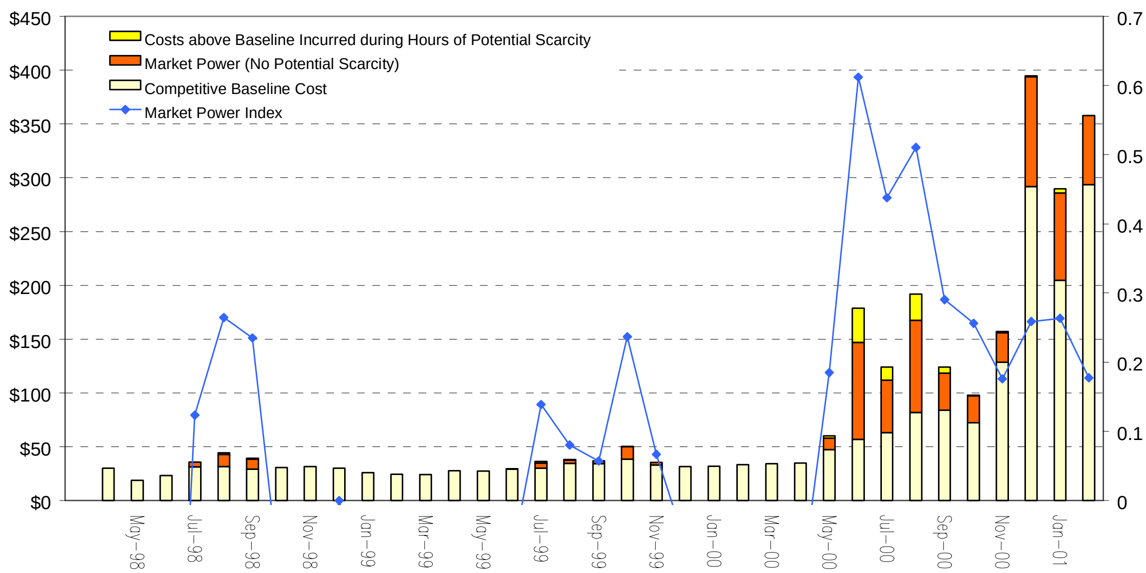
[14] In this report, we do not analyze the market power in natural gas markets that dramatically influenced electricity prices.

studies was to provide empirical evidence on an individual seller's ability to exercise market power in California's wholesale energy market since May of 2000, and to emphasize the need for effective, comprehensive action to prevent the exercise of market power in the future. The studies quantify the potential overall impact of the exercise of market power on wholesale prices. They also provide evidence that overall market outcomes resulted to a large degree from the exercise of market power by individual entities, rather than from the effect of scarcity in the market.

The first study[15] is an analysis of the impact of market power on overall system prices based on the system price-cost markup for the combined Power Exchange (PX), ISO markets, and other bilateral transactions scheduled through the ISO. Figure 4 presents one of the main results of this study (See Chapter 6 of the Technical Appendix for more details), which is a measure of the degree to which actual market prices exceed an estimated competitive baseline price. In this analysis, cost of gas is valued at spot market prices, NOx emissions costs at spot prices, and hours of potential resource scarcity were explicitly incorporated into the analysis. Results show that after incorporating potential NOx costs and hours of resource scarcity into the analysis, over 30% of wholesale energy costs over the last year can be attributed to market power – a level that clearly exceeds the range that may be consistent with a workably competitive market. We provide compelling evidence that market power rather than increases in the cost of production explain the significant portion of the price levels seen in the summer of 2000.

[15] *Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market*, prepared by Eric Hildebrandt, Manager of Market Monitoring.

Figure 4. Price Analysis by Component of Costs, Market Power and Scarcity



*Scarcity is defined as hours when operating reserves dropped below 10% of load.

When extrapolated to the total wholesale energy market (excluding generation owned or under contract to the major investor owned utilities), results of this study showed that the potential additional net cost to the IOUs exceeded $6.8 billion for the period May 2000 through February 2001. In assessing the impact of market power on higher prices, we recognize that not all incidences of prices exceeding system marginal cost are results of market power. We accounted for prices above competitive levels to be legitimate during hours of shortage of supply as shown in the graph above. Regulators and others have expressed concern that prices be sufficient to make investments in new supply profitable, so that the entry of additional supply is encouraged. The first study considers this, and concludes that prices had significantly exceeded the cost of new supply options. Thus, a market power mitigation plan that is adopted on a going forward basis can be designed significantly to reduce wholesale prices observed over the last year, while still providing sufficient opportunity for recovery of costs in new investment.

The second study[16] examined bidding behavior of individual market participants in the ISO real-time market. It addressed the issue of whether high prices were actually due to the exercise of market power by individual participants, or were simply due to low supply relative to demand. The study identified a methodology for assessing bidding strategies used by individual suppliers to systematically maintain high prices. It

16 *Empirical Evidence of Strategic Bidding in California ISO Real-time Market*, prepared by Anjali Sheffrin, Director, Dept. of Market Analysis. CAISO filing before FERC in Docket No. EL00-95-012 on March 22, 2001.

defined a methodology to assign individual responsibility for setting market-clearing prices through analyzing bid curves. It further explored the bidding strategies suppliers used to ensure that markets cleared at high prices. The study's fundamental finding is that a wide range of suppliers systematically bid capacity into the ISO real-time market at prices several times above the actual cost of production. Since the ISO's markets clear at uniform prices, sellers were able to command high prices for themselves as well as for other sellers.[17] The evidence described in this study provided a direct link between the observed pattern of high prices and the bidding behavior of individual suppliers to produce those prices.

In Chapter 6 of the Technical Appendix, we analyzed the reasons that market power results could not be diagnosed using standard market share analysis. We offer two alternative tools to estimate the potential market power, which reveals the relationship between market demand and supply conditions and the market power impacts: These are the *residual supply index* (RSI), which measures the adequacy of supply to meet demand when the single largest *net seller* is not available, and the *price-cost markup*, which measures the amount by which actual prices exceed the prices we would expect under competitive conditions (i.e., system marginal cost). We also study the distinction between market power and scarcity, based on the adequacy of available supply to meet system load. In evaluating this distinction, we demonstrate that high prices were quite frequent even in situations during which supply was not particularly scarce.

Our analysis suggests that prices rise significantly above system marginal costs whenever the RSI falls below about 1.2 which is even before any individual net seller becomes pivotal. These measures can be more useful tools to determine market power of suppliers than the simplistic 20% market share rule traditionally used by FERC. The study results show that suppliers were pivotal in setting high prices for a large number of hours in summer 2000. Thus, tools such as RSI may be an effective indicator of how much market power to expect in the future. Estimates of market power will also depend on forecasted reserve margins, and estimates of key variables, such as the level of demand side responsiveness, the level of generation output covered by long-term contracts, and the market share of major suppliers.

4. Critical Market Issues and Potential Solutions

Changes to market rules and design elements have been part of the ISO's ongoing efforts to improve market functioning and efficiency since the beginning of operation in April 1998. In 2000, several events expanded the scope and significance of this effort. First, in January 2000, FERC issued an order rejecting the ISO's filing of Amendment 23, in which the ISO had sought authority to pay market-power mitigated prices when dispatching resources needed to maintain local reliability in the absence of available RMR resources. In its rejection, FERC directed the ISO to redesign its congestion management protocols to eliminate the intra-zonal congestion problems that were creating opportunities for gaming and exercise of local market power, and to create more refined locational price signals in its markets. This order prompted the ISO to

[17] The reader should not conclude that it was the uniform market clearing price mechanism that allowed the exercise of market power. Market power allows similar results under a paid as-bid market mechanism as seen in the ISO markets from Dec 2000 – May 2001.

initiate a congestion management reform stakeholder process (CM reform) in the spring of 2000, leading to a number of proposals for changes to both the real-time energy and the forward congestion management markets. However, the larger market power issues that remained unresolved by FERC since May 2000 dwarfed these problems.[18]

In response to the dysfunctional California electric markets, on November 1, 2000 FERC issued a proposed order for short and long-term changes to the California electricity market rules. On December 15, 2000 FERC issued a final Order that included a "soft cap" of $150/MWh in the California energy and AS markets, with reporting requirements on bids above $150/MWh, subject to refund in case the supplier failed to provide adequate justification for such bids. The Order also included penalties for underscheduling on load only. The Order was implemented on January 1, 2001 and was to be in place through May 2001. The Order proved to be ineffective in remedying the problems in the California energy markets. Faced with the ineffectiveness of the December 15, 2000 Order, FERC issued another Order on April 26, 2001 that primarily addressed price mitigation in the real-time market during stage 3 emergencies. It also included an availability ("must offer") requirement for non-hydroelectric generation in California during both emergency and non-emergency periods, and provided for increased authority of the ISO to coordinate generation and transmission maintenance outages and report generation outages. Again the Order fell short of mitigating prices in the forward markets, and mitigating real-time prices during non-emergency periods. It also failed to recognize the interaction of regional markets in the west ("MW laundering"). Finally, in its June 19, 2001 Order, FERC addressed both the temporal (emergency and non-emergency) and regional (California as well as the entire western United States market) price mitigation and set the stage for what appears to be a road to recovery of the energy market in California.

Based on the above discussion, it should be clear that a crucial feature in the design of competitive markets for electricity *is* the mitigation of system-wide market power. This requires that FERC implement a number of critical safeguards, including:

- Establish an *explicit* standard for just and reasonable rates and formulate an effective enforcement mechanism for this standard. This should serve as the standard for evaluating whether markets are sufficiently or "workably" competitive. This standard is essential to ensuring that market transactions can be relied upon to yield just and reasonable rates mandated under the Federal Power Act;
- Overhaul the criterion for granting market-based rate authority to sellers;
- Improve federal and state co-ordination on retail issues such as demand response programs, utilities' ability to hedge, and transmission expansion and other issues which may impede competitive wholesale market outcomes;
- Enhance the tools and authority available to the monitoring units of the RTOs in order to mitigate the undue exercise of market power;
- Provide for a mechanism to assure adequate supply of resources to support competitive market outcomes. A requirement that load serving entities (LSE) obtain adequate reserves well in advance of real time is necessary. The LSE could

[18] FERC finally did address the market power issues on a regional basis in its June 19, 2001 Order.

meet the reserve requirement with a combination of generation, firm imports on transmission, and demand-side programs.

Analysis of the events of summer 2000 indicates that federal regulatory action is necessary to mitigate the exercise of market power by suppliers in electricity markets. This conclusion is based on the following observations:

- Entry of new supply is not feasible in the short term. It takes time and considerable effort to install significant quantities of new generating capacity and to upgrade critical transmission interfaces. Peaking generation can be installed more quickly than base load, but it takes more than two years to license, site and construct the new capacity.
- California's efforts to move to forward contracting was doomed to failure in an environment in which sellers had unmitigated market power. There is no reason to believe that suppliers would voluntarily offer forward contracts at prices any lower than what they could command in spot markets.[19]
- The ISO can change its market rules to provide stronger incentives for market participants to schedule more delivery in the forward markets and less in real time. However, the actual scheduling behavior of market participants will depend on the relative attractiveness of the full range of options available to them. For example, the ISO can require that each SC schedule at least 95 percent of its actual load by the close of the hour-ahead market and can impose a stiff penalty on any unscheduled metered load outside the five-percent margin. The SC's scheduling behavior will still depend on the relative cost of real-time energy plus penalty, compared with its opportunity cost of forward energy, over which the ISO has no control.
- Finally, the problem of inadequate demand responsiveness is largely a retail market issue to be developed through curtailable programs, widespread installation of hourly metering, greater retail competition, and energy efficiency programs. These are under the purview of the CPUC, and are beyond the ISO's jurisdiction. While the ISO can provide enhanced opportunities for loads to sell into its AS and real-time markets, only certain types of loads will be able to participate in these markets. A more comprehensive program for installing real-time meters is crucial for promoting price responsive demand and mitigating market power in wholesale spot markets.

Any market power mitigation measure must be designed to limit the impacts of market power over a time horizon of roughly two years, to provide consumer protection and market stability while the underlying structural problems are addressed. At the same time, these measures must be carefully designed, to avoid undue interference with the economic incentives that result in efficient market outcomes. For example, real-time prices allow investors to evaluate the earning potential of new generation, and enable consumers equipped with price-sensitive "smart thermostats" to limit usage during periods of high prices.

The ISO is contemplating market reforms as part of its ongoing effort to improve the overall competitiveness and efficiency of California's wholesale energy markets. Among

[19] Thus the State of California's forward contracts with suppliers in the winter of 2001 yielded prices which have been termed market power on the installment plan. Forward contracting would only be helpful if mandated by FERC at a regulated price when market power is already being exercised.

the critical market issues and potential solutions the following are particularly notable:

- **Local Market Power** - Local market power arises when constraints in the transmission system require specific levels of output from generators at specific locations. While the actual capacity requirements may vary with system conditions (i.e., load levels, path ratings, facility outages, etc.), the potential for market power abuse is a continuing problem, simply because the ownership of resources in each of these "local reliability areas" (LRAs) is highly concentrated. The ISO approaches this problem in two ways: (1) by calling upon Reliability Must-Run (RMR) contracts with individual generating units, and (2) by using its authority under the tariff to call a non-RMR unit needed for local reliability *out-of-sequence* (if the unit's bid price is above the market clearing price) or *out-of-market* (if the unit has not bid into the market) and pay market power mitigated prices at locations where local reliability needs arise but no RMR units are available. The second approach was given a severe setback, by FERC's Order of April 12, 2000, rejecting the ISO's request for authority to pay mitigated prices to units needed for local reliability when those units have submitted bids. As a result of this Order, the ISO has had to pay non-RMR resources their bid, even though the bidders were able to exercise local market power by submitting bids at the price cap, in full knowledge that the ISO had no choice but to accept those bids. The cost of dispatch under this rule amounted to more than $100 million between February and October 2000. The ISO continues to explore alternative mechanisms for mitigating local market power.
- **Congestion Management Reform** - In response to the FERC's January 9, 2000 Order, the ISO initiated an extensive congestion management reform effort involving numerous stakeholder meetings and the participation of the Market Surveillance Committee.[20] As initially articulated in FERC's Order, the problems to be solved were (1) the gaming and market power opportunities that were inherent in the ISO's intra-zonal congestion management approach (due primarily to the ability of market participants to establish infeasible forward schedules), and (2) the need for more refined locational price signals. The ISO identified three key deficiencies in the existing congestion management market design:

    1. The representation of the transmission system used for forward CM does not reflect the actual operation of the system in real time. It results in the ISO accepting forward schedules that cannot be accommodated and must be adjusted in real time.
    2. The ISO lacks effective means to address the absence of competitive markets for reducing congestion in certain local areas (i.e., RMR is insufficient to meet all local reliability and intra-zonal congestion management needs).
    3. The merit order of bids in the real-time imbalance energy market does not reflect the effectiveness of units in resolving particular congestion conditions.

    The ISO's congestion management redesign strategy aims to correct these deficiencies by managing and pricing all scarce transmission resources in a

[20] The congestion management reform effort has since been replaced by a comprehensive market redesign effort scheduled to be implemented in 2002.

consistent manner across all markets, from forward scheduling of energy flows on the ISO grid and procurement of reliability services, through real-time operation.

- **Phantom Congestion.** The prior allocation of substantial portions of inter-zonal transmission capacity to the holders of existing transmission contract (ETC) rights has been a significant source of inefficiency for the ISO's forward congestion management markets. Major portions of ETC capacity regularly go unscheduled, requiring the ISO to reserve the full amount of this capacity until after the day-ahead and hour-ahead markets have closed, even though significant amounts of ETC ultimately become available in real time. The result is that the capacity available to the market for forward scheduling is often much less than will be physically available in real time, leading to inflated usage charges. The ISO is considering solutions to relieve this problem including: working with non-ISO-member ETC holders to bring them into the ISO system, in such a way that their ETC rights are made available to the ISO congestion markets; and developing a recallable transmission service (RTS) mechanism to allocate unscheduled ETC capacity to the market in the forward markets on a non-firm basis, subject to recall if ETC holders choose to schedule that capacity after the forward markets close.
- **Incentives for transmission expansion.** Creating market incentives for transmission expansion is one of the most challenging aspects of the electrical industry's restructuring. The difficulty lies both in the lumpy nature of transmission upgrades and the public good aspect associated with networks. The problem is further complicated by the fact that the existing transmission grid was built under a regulated monopoly paradigm, in which the utilities optimized their investment in transmission and generation in an integrated fashion. As a result, the ISO grid has some critical areas where transmission is severely inadequate to support competition in generation and gives rise to persistent local reliability and local market power problems. Given these difficulties, and the fact that transmission costs constitute only a very small portion of the total cost of electric service, one pragmatic strategy would be for the ISO itself to determine and undertake transmission upgrades rather than rely on the market. Such a strategy would bring the existing system up to a level adequate to support workable competition throughout the ISO control area under normal operating conditions.