CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis[1]

CC: ISO Governing Board, ISO Executives

Date: July 20, 1999

Re: ***Market Analysis Report***

Key Market Conditions for the June 1 to July 13, 1999:

This memorandum summarizes key market conditions, developments, and trends for the period June 1 to July 13, 1999. More detailed information is provided in the attached Weekly Market Reports.

In the California Energy Markets:

June:

- For the first week of June low loads and abundant hydro led to moderate energy prices. However, as temperatures warmed across the region, energy prices for the rest of June increased significantly. Peak prices for the first week of June averaged $20.53/MWh in the PX (unconstrained) and $12.02/MWh in the ISO real-time market. For the period June 8-29, these same prices averaged $31.06/MWh and $28.89/MWh.

- Extremely high loads occurred from June 28-29 with peak loads of 38,000 MW and 40,500 respectively. These higher than expected loads, coupled with the loss of several generating unit, led to some price spikes in the ISO's real-time energy market. On June 28, the real-time energy price reached $200/MWh in hour ending 16 and on June 29 the real-time energy price exceeded $230/MWh in hours ending 14-19.

July:

- Though loads were moderate for the first week of July, they hit record highs the second week. On July 12, system loads in the ISO control area peaked at 45,574 MW, shattering last year's record of 44,759 MW set on August 3, 1998. Loads were also quite high on July 13, 1999 peaking at 44,511 MW but moderated by July 14. July energy prices followed load patterns fairly closely. During the first nine days of July when loads were fairly moderate, the PX unconstrained price for peak hours averaged $30.93/MWh and the ISO peak hour real-time price average $18.11/MWh. During this period, the ISO was decrementing significant amounts of generation and this tended to depress real-time prices. With the significantly higher loads of July 10-13, energy prices rose dramatically. The PX

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[1] The Market Surveillance Unit has been renamed to reflect its dual roles of monitoring markets and analyzing design changes. We are now the Department of Market Analysis (DMA).

unconstrained price for peak hours reached $153.83/MWh and averaged $50.11/MWh and the ISO peak hour real-time price reached the $250 price cap in several hours and averaged $93.29/MWh.

In the Ancillary Service Markets:

Day-ahead Ancillary Service Prices

- Regulation, the most volatile of the A/S markets, continues to exhibit significant hour-to-hour and day-to-day volatility. Prices in the regulation market are highest in the morning hours when demand for downward regulation is high and in the evening hours when demand for upward regulation is high.

- For the most part, average day-ahead ancillary service prices declined in June. Two factors contributed significantly to this decline. First, low loads and abundant hydro generation resulted in low prices for the first week of June. Secondly, beginning on June 12, the ISO implemented a new algorithm for determining regulation requirements that resulted in significantly lower requirements. This lower demand for regulation reduced market clearing prices in the regulation market and freed up capacity for other markets which reduced prices in these markets as well.

	May, 1999		Jun 1-30, 1999		Jul 1-13, 1999	
	Peak	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Regulation*	23.33	30.67	20.06	28.22	38.56	34.09
Spin	6.58	1.46	8.17	1.13	22.26	1.11
Non-spin	4.45	0.57	3.90	0.32	23.03	0.13
Replacement	2.48	0.00	2.02	0.00	24.33	0.00

*** Average Regulation Prices Exclude May 16, 1999 due to the large negative price spikes that occurred on this day.**

- Average day-ahead ancillary service prices increased sharply in the first two weeks of July which can be attributed to high prices during July 12-13 when system loads were extremely high. During this period the $250/MW price cap was hit in five hours in the regulation market, three hours in the non-spinning reserve market, and four hours in the replacement reserve market. There were also numerous instances of prices in excess of $200/MW in all four ancillary service markets.

Ancillary Service Costs

- On April 6, 1999, in an effort to create a more active hour-ahead market, the ISO began shifting a portion of day-ahead ancillary service requirements to the hour-ahead market. For April 1999, the average daily costs of ancillary service capacity bought in both the day-ahead and hour-ahead market was $1,125,000 representing about 8% of the estimated wholesale value of actual hourly loads in the ISO control area. For May and June 1999, the average daily cost was approximately $1.3 million represent approximately 9% and 11% of the estimated wholesale value of actual hourly loads in the ISO control area, respectively. For the first two weeks of July (July 1-13) average daily ancillary service costs increased twofold over May and June levels. This increase is largely due to very high prices for the peak demand days of July 12-13. The total daily cost of ancillary services on July 12 and July 13 were $ 7.9 million and

$9.6 million, respectively. Though the average daily cost of ancillary service doubled in July, the relative cost (i.e. as a percent of estimated overall energy costs) remained roughly the same at 10%.

Month	Avg. Daily Cost* ($ million)	% of Energy Costs*
April	1.125	8%
May	1.309	9%
June	1.333	11%
July 1-13	2.792	10%

*** Includes day-ahead and hour-ahead procurement costs**

**** Energy cost = actual hourly loads multiplied by the PX Day-ahead Unconstrained MCP.**

In the Congestion Management Markets:

- Import congestion on the northwest paths increased significantly in June compared to May levels as higher energy prices attracted more imports from the northwest. For the month of June, COI was congested about 17% of peak hours with an average price of $10.57/MW and 10% of off-peak hours with an average price of $3.18/MW. Congestion on the ISO's portion of the Pacific DC Intertie (NOB) also increased from May levels with north to south congestion in June occurring in roughly 11% of peak hours with an average price of $3.56/MW and in 2% of off-peak hours with an average price of $4.88/MW.

- From July 1 to July 13 import congestion on the northwest paths picked up dramatically. During this period COI was congested during 58% of peak hours and 37% of off-peak hours and NOB was congested in 27% of peak hours and 5% of off-peak hours. Day ahead prices on COI ranged from $.01/MW to $66.59/MW and averaged $13.23/MW. Day ahead prices on NOB ranged from $.10/MW to $49.64/MW and averaged $10.68/MW.

- Congestion levels on the southwest paths were generally lower in June as higher loads in the southwest reduced flows into California. Import congestion on the Eldorado branch group was similar to May levels for peak hours with congestion occurring in approximately 4% of peak hours. Off-peak congestion declined from 16% in May to 6% in June. June prices were on average higher on Eldorado, averaging $10.65/MW in peak hours and $7.53/MW in off-peak hours. There was no congestion on Palo Verde in June.

- Congestion levels on the southwest paths were minimal from July 1-13. However, there was significant congestion on Path 15 in the south to north direction. During this period, Path 15 was congested south to north in 25% of peak hours and 73% of off-peak hours. Prices on Path 15 ranged from $.01/MW to $58.86/MW and averaged $11.81/MW.

Issues under Investigation:

- **Sale of PG&E Hydro Assets.** The legislature asked the ISO's Market Analysis Department to analyze market power mitigation measures for the potential sale of PG&E's hydro assets. A number of mitigation options were reviewed including contracts for differences, divestiture to a large number of owners, and minimum quantity and bid price requirements. Market Analysis, in collaboration with ISO Operations, presented a white paper (which is being provided to the Board as an attachment to the Legislative Committee memorandum) that proposed safeguards to be included in the conditions for any transfer of the assets. The case studied in the minimum capacity bid option was if PG&E were to transfer the entire hydro portfolio to its unregulated affiliate. This case would require the PG&E affiliate to bid in A/S markets to ensure bid sufficiency. The PG&E affiliate would be a price taker for this minimum amount. They would be able to bid additional amounts in any A/S market at a market index bid cap, and would earn the market clearing price. The proposal is intended to ensure that a new owner is not able to set the market clearing price for the minimum requirements, but continues to have an incentive to compete in all A/S markets.

- **Possible Day-Ahead Congestion Gaming.** For operating day May 25, 1999, for approximately 16 hours, several thousand MWs were scheduled through the PX across ISO path Silver Peak (SR3) from Nevada to Southern California. Silver Peak has a maximum available capacity of 15 MW. This strategic bid affects the PX zonal price, but not other SCs scheduling directly with the ISO. When the PX submitted the schedule to the ISO, our procedures required that we award several thousand MWs of adjustment bids to relieve the congestion. The assessment of Usage Charges to the PX resulted in significantly higher clearing prices in the PX day-ahead market. This incident has created some concerns about possible market gaming and abuse. Market Analysis investigated the issue in collaboration with the PX Market Compliance Unit and suggested some measures that the PX could implement to prevent this event from re-occurring. The PX is investigating the issue further to assess various options.

- **Intra-zonal Congestion and Creation of New Zones.** Based on intra-zonal congestion costs associated with Path 26, it appears that this path is a candidate to become an inter-zonal interface. Section 7.2.7 of the ISO Tariff includes provisions for creation, modification, and elimination of zones. The Tariff sets a two-part test for the creation of a new zone: 1) the cost of intra-zonal congestion mitigation; and 2) existence of workably competitive generation markets on both sides of the interface for a substantial period of the year. However, no definition is provided in the Tariff for a "workably competitive generation market", and no explicit requirement is set for competitive markets within each new zone. We are studying the issue to define measures for workable competitiveness. Path 26 intra-zonal congestion will be used as a test case. Other options to new zone creation under review include: raising the transfer capability of Path 26 by implementing Remedial Action Schemes (RAS); moving the boundary of the two active zones from Path 15 to Path 26; having two zones with floating boundaries (Path 15 or Path 26) depending on ISO's forecast of congestion conditions for each operating day; and a transmission system upgrade/reinforcement.

  A parallel investigation is also underway to determine the proper course of action if it is found that there is no workably competitive market to mitigate intra-zonal congestion. The solution may involve the use of RMR units where available, adding intra-zonal congestion mitigation as a criterion (in addition to the current local reliability criteria) for designation of RMR units, or devising a cost-based tariff for incremental and decremental bids exclusively for intra-zonal congestion mitigation.

- **Use of Real-time Generation Meter Multipliers (GMMs).** At present actual transmission losses are not accounted for in the balanced forward market (day-ahead and hour-ahead) schedules. A GMM=1 is used in both day-ahead and hour-ahead markets for scheduling purposes. Presently, a SC can use the hour-ahead GMMs to decide how much to generate at each location to meet its effective schedule commitment with minimal or no real-time deviation. This provides a mechanism for a SC to bypass the current limitation of having to use GMM=1 for scheduling in the forward markets. However, because actual losses can be different from losses computed based on hour-ahead schedules, differences are allocated as Unaccounted For Energy (UFE) and charged to all SCs in proportion to their load.

In its October 30, 1997 Order, FERC approved ISO plans to "recalculate GMMs based on actual data on Generation and Demand after the fact and to use these ex-post GMM's to determine each SC's loss responsibility ". The Ex-post GMMs based on actual data cannot be used in determining loss responsibility until ISO's State Estimator (SE) is implemented (a Stage 2 Power Management System function scheduled for implementation in early 2000), and the ISO gives "30 days notice posted on the WEnet of its intent to use them". As soon as the software changes are implemented, the ISO plans to use forecast GMMs (based on day-ahead and hour-ahead markets) for scheduling and real-time GMMs (based on State Estimator results) for settlement purposes. Some market participants have expressed concerns that using actual GMMs for settlement purposes will undermine their ability to satisfy their forward market commitments. We are studying the issue. We will review market efficiency impacts of using hour-ahead GMMs for settlement purposes on an ongoing basis or as a temporary measure until the software allowing real-time GMMs to be used for settlement purposes is available. Forward market GMMs would be used as a basis for acceptance or rejection of "balanced" schedules as soon as the PX and other SCs are able to accommodate them in their day-ahead and hour-ahead schedules.

- **Potential Exercise of Market Power in the Hour-ahead A/S Market.** Starting April 7,1999, the ISO has been deferring part of its day-ahead A/S requirements to the hour-ahead market. This was a request made by market participants in the A/S redesign process to increase liquidity of the hour-ahead market and reduce A/S costs.

  We expected that initially this would result in higher hour-ahead prices, but that increased liquidity of the hour-ahead market would attract hour-ahead market supply and result in price equilibrium between the day-ahead and the hour-ahead markets. In practice, hour-ahead market prices constantly increased, particularly in the Regulation market, where the price cap was hit frequently. This is partly attributable to the separate procurement of upward and downward regulation with a single market-clearing price, a practice that will be changed this summer to allow separate MCPs for upward and downward regulation. However, announcing exactly how much the ISO will procure in each of the day-ahead and the hour-ahead markets, which can provide incentives for some suppliers to withhold capacity from the day-ahead market (or bid very high prices), and show up in the hour-ahead market where a relatively limited number of suppliers can provide regulation depending on prevailing hydro conditions and technical unit characteristics.

  In response to these concerns, the ISO has advised Market Participants that an ***advisory*** percentage deferred to the hour-ahead market will be posted on the Web. The actual amount purchased in the day-ahead and hour-ahead markets is based on a number of factors affecting operating requirement, including updated load projections, actual system conditions (e.g. generator availability and outages), weather conditions, estimated hour-ahead self provision, thickness of the hour-ahead market, and the purchase price of the A/S service. Based on our observation of A/S market behavior, bid sufficiency, and pivotal suppliers, we are considering an ISO procedure for day-ahead purchases that would maintain a Residual Supply Index (RSI) above a minimum threshold.

- **Public Data Release Policy.** At its July 9th meeting, the Market Surveillance Committee recommended that the ISO should release aggregate bid data as soon as practicable, and release all bid data (including the identity of the bidders) with a three-month time lag. A vote by the ISO Board and a FERC tariff change are required to implement this recommendation. We are currently estimating the internal resources required to implement this recommendation. We will review the impact of data release on market efficiency, market power, and possible incentives or disincentives it might create for participation in the ISO markets or the bilateral markets. The next steps include soliciting stakeholder input, formulating a management recommendation, and sending a recommendation to the ISO Board for action in August.