Attachment A

Analysis of Market Power in California's Wholesale Energy Markets

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November 21, 2000

This paper summarizes the recent performance of California's wholesale energy markets, and provides a description of the methodology and results of a more quantitative analysis of the impact of market power and potential scarcity on wholesale energy prices.

Overview of Market Performance

Over the California ISO's first two years of operation, supply conditions were sufficient to ensure workable competition among suppliers for most hours of the year, with competition leading to prices closely aligned with the costs of supply required to meet demand. Analysis by the ISO's Department of Market Analysis (DMA) shows that when significant supply exists (e.g. when total available supply reaches or exceeds 120% of system demand for energy and ancillary services), prices tend to be close to the variable operating cost of the highest-cost generating unit required to meet demand. However, during high load hours and hours of limited supply, the combination of tight supply conditions and the limited ability of consumers to reduce consumption in response to prices creates the situation in which any firm that owns a significant share of the generation serving the ISO system can exercise market power to inflate wholesale prices.

The persistently high prices in California's wholesale energy markets since late May of this year reflect, in part, a combination of several underlying factors, or "market fundamentals," including: (1) unusually high demand for electricity region-wide due to unseasonably high temperatures and recent economic growth, (2) a doubling of gas prices over the last year, and (3) the fact that no significant new supply has been added in California in recent years. However, the combination of very tight supply and demand conditions — in conjunction with the very limited ability of consumers to reduce consumption in response to rising prices — has also created the opportunity for the exercise of market power during many hours, as well as absolute shortages of supply during some hours. The persistent exercise of market power since late May of this year has inflated wholesale prices well above levels that would have resulted under competitive market conditions, even after taking into account underlying "market fundamentals" that have increased supply costs and hours of potential scarcity of supply. A more detailed description of the methodology and results of a more quantitative analysis of the impact of market power and potential scarcity on wholesale energy prices by the DMA is provided in the following section of this paper.

Analysis of Market Power and Scarcity

The persistently high prices observed in California's wholesale energy markets since late May during periods when no absolute scarcity of supply exists provide a strong indication of the successful exercise of significant market power. For instance, over the 12 month period from October 1999 to September 2000, while only a few peaking units have had estimated operating costs of $100/MWh, the combined hourly average wholesale price of energy in the PX/ISO markets has exceeded $100/MWh of load served more than 1,200 hours, or over 14% of total hours on an annualized basis. In contrast, the average wholesale price of energy in the PX/ISO markets exceeded $100/MWh during only 1% to 2% of hours during the ISO's first two years of operation.

The DMA has also performed more systematic, quantitative analyses of market power and any potential scarcity of supply within the ISO system over the ISO's first two and one half years by comparing the difference between the actual wholesale price of energy in the ISO system and an estimate of baseline costs that would be incurred under competitive market conditions. The competitive baseline price used in this analysis represents the estimated variable operating cost of the marginal thermal generation unit within the ISO system needed to meet system demand each hour, after taking into account the actual supply of imports and other supply resources within the ISO control area. The degree to which the actual wholesale energy price (including load met in the PX Day Ahead market and the ISO real time market) exceeds this competitive baseline cost (expressed as a percentage of actual wholesale prices) represents the *price-cost markup.*

The methodology used to determine this competitive market baseline and the price-cost mark-up is as follows.

1. First, the operating cost of major non-utility owned thermal units within the ISO system are estimated based on unit heat rates, spot market gas prices, estimated O&M costs of $4/MWh for combustion turbines and $2/MWh for other thermal units.[1]

2. Second, the availability of these units is determined for each operating day based on metering, scheduling, and bid data. The availability of individual units each operating day was based on whether or not a unit was actually in operation and/or bid into the ISO markets. Specifically, if metering information, final energy and ancillary service schedules, and supplemental energy bids indicated a unit was available during any hour of a day, it was assumed the unit's full capacity was available for that operating day.

3. Third, a thermal supply curve is developed by ranking units based on price, and summing up the capacity available at each price level. In the base case of our analysis, we also include real time energy bids from imports submitted as Replacement Reserve and Supplemental Energy bids in this supply curve (rather than simply "netting out" these imports from ISO system demand).

4. Fourth, the net demand that must be met by these sources of supply is calculated for each hour *t* as follows:

$$\text{Net Demand}_t = \text{System Energy Demand}_t - \text{Imports}_t - \text{Residual ISO Supply}_t - \text{Estimated System Losses and Unaccounted for Energy}_t$$

Where:

$$\text{System Energy Demand}_t = \text{Actual ISO System Load}_t + \text{Upward Regulation Requirements}_t$$

$$\text{Imports}_t = \sum_i \text{Final Hour Ahead Energy Schedule}_{i,t} + \text{Real Time Energy Dispatched}_{i,t}$$

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1. Analysis of the potential impact of NOx emissions costs was also performed based on estimates of the potential cost of emission credits in Southern California. Results of this analysis indicate that emissions credits costs could have a significant impact on prices toward the late summer months (i.e. starting in August), but that overall prices were still significantly in excess of competitive levels. However, results of this analysis are not presented due to significant uncertainty about actual emission credit costs that should be used in such analysis, and the cost and feasibility of alternative abatement options. In addition, it should be noted that on a going forward basis, emissions costs that should be included in the cost of generation should be based on the cost and feasibility of alternative abatement options, rather than the price at which emissions credits may ultimately be traded.

Residual ISO Supply $_t$ = $\sum_j$ Max [Metered Output$_{j,t}$, Final Hour Ahead Energy Schedule$_{j,t}$ + Upward Regulation Capacity Scheduled$_{j,t}$ + Real Time Energy Dispatched$_{i,t}$ + RMR Schedule Change$_{j,t}$]

i = All import schedules into the ISO control area

j = All generating resources within the ISO control area other than major thermal units

System Losses and Unaccounted for Energy in each hour *t* were estimated based on the difference between hourly system loads reported by the ISO based on telemeter data and the summation of estimated generation from all sources within ISO control area plus final import schedules.[2]

5. Fifth, a competitive baseline price is calculated based on the supply curve of non-utility thermal units and real time energy import bids (Step 3) and the net demand needing to be met from these sources of supply (Step 4).

6. Sixth, the *price-cost markup* is calculated based on the degree to which actual market costs (net of generation owned or already under contract to UDCs) exceed costs that would be incurred at this competitive baseline price. Specifically, the price cost markup is calculated for each month (or other time period) by aggregating results for each hour t as follows:

$$\text{Markup} = \frac{\sum \text{Net Market Costs}_t - \text{Competitive Baseline Costs}_t}{\sum \text{Competitive Baseline Costs}_t}$$

Where:

Net Market Costs$_t$ = (Total ISO Load$_t$ - UDC Generation$_t$) $\times$ Average System Energy Price$_t$

Average System Energy Price$_t$ = (Scheduled Load$_t$ $\times$ PX MCP$_t$) + (Unscheduled Load$_t$ $\times$ Real Time MCP$_t$) [3]

Competitive Baseline Costs$_t$ = (Total ISO Load$_t$ - UDC Generation $_t$) $\times$ Competitive Baseline Price$_t$

[2] For virtually all peak hours with relatively tight supply and demand conditions, the difference between the system load and the sum of unit level estimates of generation (plus import schedules) was between approximately 1% to 3% of the ISO official estimate of system loads. This is within the range expected to line losses. Most importantly, however, this reconciling reported system loads with "bottom up" calculations based on scheduled and metered generation of individual resources and imports schedules ensures that any missing or inaccurate data does not introduce significant errors into the analysis.

[3] Estimated PG&E area loads (net of utility generation) multiplied by prices in NP15 and net SCE/SDG&E area loads multiplied by SP15 prices.

7. In order to assess the degree to which high wholesale prices may be attributable to absolute scarcity of supply, rather than market power, we also identify the portion of the price-cost markup occurring during hours of potential resource scarcity. In this analysis, scarcity is defined based on hours when total available supply in the ISO system (including import bids and out-of-market purchases) is less than total system demand for energy plus 10% ancillary services (representing about 3% upward regulation, and 7% operating reserve). Additional details of the methodology and results of our analysis of scarcity were presented in a previous DMA report (*Report on California Energy Market Issues and Performance: May-June, 200*0, Special Report by ISO DMA, August 10, 2000).

Table 1 presents the results of this analysis of overall competitiveness of California's wholesale energy markets based on the markup of prices above costs. As shown in Table 1, wholesale costs exceeded this competitive baseline by only 8% during the first year of operation and only 10% during the second year of operation.[4] During the most recent twelve months of operation, however, wholesale costs have exceeded this competitive baseline by 43%. While a significant portion of the increase in wholesale costs above this competitive baseline have been incurred during hours of potential absolute resource scarcity, the bulk of these additional costs are attributable to market power, rather than scarcity. In addition, prices continued to significantly exceed competitive levels even after the ISO's real time price cap was lowered to $250 in August 2000.

Both the methodology and results of the analysis summarized in Table 1 are similar to analysis performed by the Chairman of the ISO's Market Surveillance Committee (MSC) in conjunction with researchers at the University of California Energy Institute.[5] Table 2 summarizes key differences in the methodologies used in these two studies. Although conducted independently and with somewhat different assumptions, both of these studies reach essentially the same conclusion with respect to the significant increase and level of market power being exercised in California's wholesale energy markets since late May of this year.

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[4] Results presented in Table 1 vary somewhat from preliminary results submitted as part of the ISO's October 20 filing to FERC due to modifications in the gas price data used in the analysis. The major effect of these gas price changes was to increase the estimated market power during the first and second years of operation (from 1% and 6%, respectively, to 8% and 10%). Results in Table 1 are based on average daily sport market prices reported for PG&E Citygate and Southern California Border Average (for units in NP15 and SP15, respectively), plus estimated transportation charges (ranging from approximately $.20 to .$50/MMBtu since April 1998).

[5] Borenstein, Severin; Bushnell, James; and Wolak, Frank, "Diagnosing Market Power in California's Restructured Electricity Markets", August 2000; Updated results through June 2000 presented in *An Analysis of the June 200 Price Spikes in the California ISO's Energy and Ancillary Service Markets*, MSC Report, September 6, 2000).

Table 1. Analysis of Impact of Market Power on Wholesale Energy Prices

Period	Avg. Wholesale Cost ($/MW) [1] A	Competitive Baseline Costs($/MW) B	Avg. Price-cost Markup ($/MW) (A – B)	Markup during Hours of Potential Scarcity [2]	Markup during Hours of No Potential Scarcity	Markup as Percent of Total Wholesale Cost [3]
Apr-98	$23	$26	-$3	$0	-$3	-12%
May-98	$13	$11	$2	$0	$2	15%
Jun-98	$14	$20	-$6	$0	-$6	-37%
Jul-98	$36	$30	$8	-$1	$9	21%
Aug-98	$43	$32	$15	$2	$13	33%
Sep-98	$38	$28	$12	$1	$11	30%
Oct-98	$27	$29	-$2	$0	-$2	-6%
Nov-98	$26	$30	-$3	$0	-$3	-11%
Dec-98	$30	$28	$3	$0	$3	9%
Jan-99	$22	$25	-$2	$0	-$2	-10%
Feb-99	$20	$23	-$3	$0	-$3	-16%
Mar-99	$20	$23	-$2	$0	-$2	-12%
Apr-99	$25	$26	$0	$0	$0	0%
May-99	$25	$23	$3	$0	$3	10%
Jun-99	$27	$27	$2	$0	$1	6%
Jul-99	$35	$29	$8	$1	$7	21%
Aug-99	$38	$33	$6	$1	$5	15%
Sep-99	$36	$33	$4	$1	$4	12%
Oct-99	$50	$37	$14	$0	$14	27%
Nov-99	$35	$31	$5	$0	$5	13%
Dec-99	$30	$30	$0	$0	$0	0%
Jan-00	$32	$30	$2	$0	$2	5%
Feb-00	$30	$32	-$2	$0	-$2	-5%
Mar-00	$30	$33	-$3	$0	-$3	-10%
Apr-00	$31	$31	$0	$0	$0	1%
May-00	$58	$45	$16	$1	$15	26%
Jun-00	$147	$54	$105	$30	$75	66%
Jul-00	$112	$54	$64	$15	$48	54%
Aug-00	$167	$63	$108	$29	$79	63%
Sep-00	$118	$70	$52	$7	$45	42%
Oct-00	$97	$64	$34	$0	$34	35%
Apr 1998-Mar 1999	$27	$26	$2	$0	$2	8%
Apr 1999-Mar 2000	$33	$30	$3	$0	$3	10%
Nov 1999-Oct 2000	$78	$46	$35	$8	$28	43%

[1] Average Wholesale Cost = [Hour Ahead Schedule$_{NP15}$ x PX MCP $_{NP15}$] + [Hour Ahead Schedule$_{SP5}$ x PXMCP$_{SP15}$] + [(System Load Hour $_{NP15}$ - Ahead Schedule$_{NP15)}$ x Real Time MCP $_{NP15}$] + [(System Load Hour $_{SP15}$ - Ahead Schedule$_{SP15)}$ x Real Time MCP $_{SP15}$] ,

where zonal schedules and loads are estimated based on Utility Distribution Company (UDC) area schedules and generation (with NP15 prices applied to PG&E area and SP15 prices applied to other SCE and SDG&E areas).

[2] Hours of potential scarcity defined based on hours when total available market supply of capacity was less than total system energy demand plus 10% ancillary services (3% upward regulation, plus 7% operating reserve).

[3] Overall Price-Cost Markup = (Actual Wholesale Costs - Baseline Costs) / Baseline Costs, with hourly costs weighted by total system loads minus generation owned or under contract to UDCs (utility-owned generation, QFs, etc.)

Table 2. Comparison of Methodologies

Component of Methodology	BBW [1]	ISO/DMA [2]
Market Energy Price compared to competitive baseline	Unconstrained PX Market Clearing Price	Weighted average of zonal (constrained) PX and zonal real time price (weighed by scheduled and unscheduled load, respectively).
Thermal Unit Availability	Monte Carlo simulation of forced outage rates	Unit availability determined on daily basis based on metering, scheduling, and bid data. Unit assumed available if metering data shows unit is on, unit is scheduled in any Hour Ahead market, and/or unit is bid into the real time energy market
System Demand	Reported ISO load + Regulation Up Requirements	Reported ISO load + upward regulation requirements. Upward regulation requirements (vs. purchases) is used to avoid overestimation due to significant purchases of upward regulation up as substitute for other Ancillary Services under Rational Buyer protocol.
System Load + Losses/Unaccounted for Energy	Reported ISO load (based on telemetered data)	Reported ISO load with losses/unaccounted for energy explicitly calculated and treated as “negative” energy source. Hourly losses/unaccounted for energy calculated based on the difference between reported ISO load based on telemetered data and “bottom up” summation of hourly generation output from all unit and imports data used in analysis. This reconciles supply data used in analysis with demand data used.
Energy Output of Generating Units	Metered data with 90-day lag for submission/adjustment of settlement quality data.	Metered data used if/when it exists. Otherwise, energy estimated based on summation of scheduled energy output (Hour Ahead Energy Schedule plus real time energy dispatches, etc.) Any errors unit-level errors this may introduce are cancelled out when the summation of unit-level and import data are reconciled with telemetered system load data. This approach avoids the need to wait 90 days for final settlement data.

Table 2. Comparison of Approaches (Continued)

Net System Demand (used with cost-based supply curve to calculate competitive baseline price)	System Demand – Imports - Hydro – Geothermal – Regulatory Must Run/Must Take	System Demand – Hour Ahead Import Schedule - Minimum Reliability Requirement of Thermal RMR units – All other generation within ISO system except thermal generation of five major non-utility owners.
Thermal resource supply curve "dispatched" to meet system demand after netting out of other supply	All thermal units except Regulatory Must-Run/Must-Take (including RMR units, municipals and small suppliers)	Thermal units of five major non-utility generation owners, after subtracting Minimum Reliability Requirement of Reliability Must-Run (RMR) Units from total unit capacity.
Imports	Actual Imports + Aggregation of Adjustment bids on all paths. (See discussion on BBW, p. 27-29)	Limit on each import path included in allowable imports. Final Hour Ahead import scheduled and import energy from spinning and non-spinning reserves "netted out" of ISO system demand. Real time energy offered through replacement reserve and supplemental energy bids included in supply curve at bid price.

[1] (BBW) Borenstein, Severin; Bushnell, James; and Wolak, Frank, "Diagnosing Market Power in California's Restructured Electricity Markets", August 2000; Updated results through June 2000 presented in *An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Service Markets*, MSC Report, September 6, 2000).

[2] California Independent System Operator (ISO), Department of Market Analysis (DMA).

Summary and Conclusions

The performance of the ISO markets over the first two years of operation has shown that when supply is sufficient to cause competition among suppliers, competition leads to prices closely aligned with the variable operating cost of the highest-cost generating units required to meet demand. However, since late May of this year, the combination of very tight supply and demand conditions — in conjunction with very limited ability of consumers to reduce consumption in response to high prices — has created the opportunity for the persistent exercise of market power in California's wholesale energy markets. The exercise of this market power has inflated wholesale energy costs significantly above levels that would have resulted under competitive market conditions, even after taking into account fundamental market factors driving up costs and hours of potential scarcity of supply. While some degree of market power may be tolerable from the perspective of defining a workably competitive market, the exercise of market power since late May of this year has clearly exceeded the level that may be considered consistent with a workably competitive market. Since additions of new supply are likely to merely keep pace with or even fall short of demand growth over the next two years, the exercise of significant market power can be expected to continue – if not worsen – over the next two years absent action to more effectively mitigate system-wide market power.

The fundamental solution to mitigate this market power is to create ways for consumers to respond to increasing prices, accelerate entry to the market by new suppliers, and provide consumers the ability to avoid or hedge against the financial impacts of market power through long term contracts. Each of these structural market changes or developments are likely to require at least two years to be implemented to a degree that will ensure a workably competitive market. In the interim, mitigation of the exercise and financial impact of market power on consumers (and load serving entities that may be obligated to serve customers at limited prices) is necessary to allow continued development of deregulated energy markets.