Analysis of Payments in Excess of Competitive Market Levels in California's Wholesale Energy Market

May 2000 - 2001

FERC Settlement Conference

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Summary

This report summarizes analysis of payments in excess of competitive market levels in California's wholesale energy market from May 2000 to May 2001. The analysis was performed for the Settlement Conference in order to quantify provide potential refunds that may result under different "rate formulas", designed to determine the amount of refunds based on the difference between actual market transaction prices and prices that would result in a competitive market. It should be noted that the methodology and results of this analysis does not constitute the settlement position of California's delegation to the settlement conference. Rather, the analysis was performed to provide Commission staff, the California delegation and other participants in the conference with a potential framework for settlement discussions.

This report summarizes results two scenarios, representing a range of potential approaches may be considered for determining refunds for charges in excess of *just and reasonable* levels from May 2000 to May 2001.

- The first scenario examines potential refund levels based on energy prices that could be expected under competitive market conditions are estimated as a baseline for use in the analysis. Consistent with well established economic theory, the *competitive baseline price* upon which the ISO's analyses are based represent the estimated short-run marginal cost of the highest-cost thermal generating unit needed to meet system demand for capacity in a given hour. Results of this analysis indicate potential refund levels of $7.7 billion from sales to the ISO, CDWR and PX from May 2000 to May 2001.
- The second scenario examines potential refund levels based on an approach in which payments are limited to the actual cost of the highest cost gas-fired unit dispatched in the ISO's real time imbalance market. The scenario also excludes sales to the CDWR on a month ahead basis. Results of this analysis indicate potential refund levels of $6.1 billion from sales to the ISO, CDWR and PX from May 2000 to May 2001.

Detailed descriptions of the methodologies used in these analyses are provided in Appendix A and B of this report. The remainder of this section summarizes key results of this analysis.

In comparing results of these two approaches, it is important to note that the higher level of refunds under the ISO's competitive baseline scenario reflect the fact that this analysis accounts for the impact of both *economic withholding* (or bidding capacity significantly in excess of costs) and *physical withholding* (or failing to bid a portion of capacity into the real time market). In contrast, the second scenario does not account for the degree to which economic and physical withholding prevent all available capacity from being dispatched in merit order based on actual marginal costs. This important distinction not only explains the difference between hourly baseline price levels resulting from these two approaches – it also highlights the inefficiencies resulting from market power and the benefits of *must-bid* requirements and *bid price mitigation* in terms of basic economic efficiency.

The analysis presented in this report shows when just minor screening is applied to "filter out" the impacts of economic and physical withholding of capacity in the real time market, the marginal cost of energy actually dispatched in the real time market is just slightly above the c*ompetitive baseline level* calculated by the ISO in previous analysis presented to the commission in these proceedings. The relatively small difference between these two approaches when minor screening is applied to actual unit dispatches reinforces the validity of the ISO's competitive baseline model as an accurate measure of true system marginal costs under competitive market conditions.

The systematic and widespread practice of *economic withholding* (or bidding capacity significantly in excess of costs) and *physical withholding* (or failing to bid a portion of capacity into the real time market) in the ISO's real time market since May 2000 has been documented in a variety of filings and data submitted to the Commission. One of the direct impacts of economic and physical withholding of capacity in the real time market is that the higher cost units (and units with quicker ramp times) must be often be dispatched to meet demand that could otherwise be met by lower cost capacity withheld – either economically or physically – from the market. Thus, in order to avoid overestimating the true system marginal costs under competitive conditions, any analysis based on actual real time energy dispatches must account for the fact that energy actually dispatched in the real time market has been dispatched based on the *bid price of capacity offered* in the real time market, rather than on the *actual cost of all capacity actually available* to meet demand.

Results of this preliminary analysis can be supported by more detailed analysis the impacts of economic and physical withholding of the real time energy market:

- The impacts of *economic withholding* can be assessed by simulating how gas-fired capacity actually bid into the real time market would have been "re-dispatched" based on actual costs, rather than bid prices.
- The impacts of *economic withholding* can be assessed by identifying gas-fired capacity that was available, but not bid into the real time market. The competitive price that would result in the absence of such physical withholding can be calculated by including this capacity in the simulation of how gas-fired capacity would have been "re-dispatched" based on actual costs, rather than bid prices.

More detailed analysis is being performed to provide further support for the degree to which real time prices in the ISO system have been inflated by the exercise of market power since May 2000.

Scenario 1:
Payments in Excess of Competitive Hourly Baseline

Base Case: ISO Analysis of FERC Order Presented at Conference
(Competitive Market Baseline)

Millions of Dollars

	ISO	CDWR	PX	Total
Non-Public Sellers				
May-Sept	$1,487	$0	$236	$1,724
Oct-May	$1,697	$2,916	$279	$4,893
Total Non-Public	$3,185	$2,916	$516	$6,616
Public Sellers				
May-Sept	$301	$0	$22	$323
Oct-May	$175	$544	$42	$761
Total Public	$476	$544	$64	$1,084
Total Non-UDC (Non-Public + Public Sellers)				
May-Sept	$1,789	$0	$258	$2,047
Oct-May	$1,872	$3,460	$322	$5,654
Total non-UDC	$3,661	$3,460	$580	$7,700

Scenario 2: Payments in Excess of Highest Cost Unit Dispatched in ISO Real Time Market

Millions of Dollars

	ISO	CDWR	PX	Total
Non-Public Sellers				
May-Sept	$1,205	$0	$302	$1,507
Oct-May	$1,352	$2,081	$311	$3,744
Total Non-Public	$2,557	$2,081	$613	$5,251
Public Sellers				
May-Sept	$212	$0	$22	$234
Oct-May	$134	$456	$33	$623
Total Public	$346	$456	$55	$857
	Total Non-UDC (Non-Public + Public Sellers)			
May-Sept	$1,417	$0	$324	$1,740
Oct-May	$1,486	$2,538	$344	$4,367
Total non-UDC	$2,902	$2,538	$668	$6,107

Comparison of Results

Appendix A and B provides a description of the methodologies used to calculate system marginal costs and total potential refunds under Scenario 1 and Scenario 2, respectively.

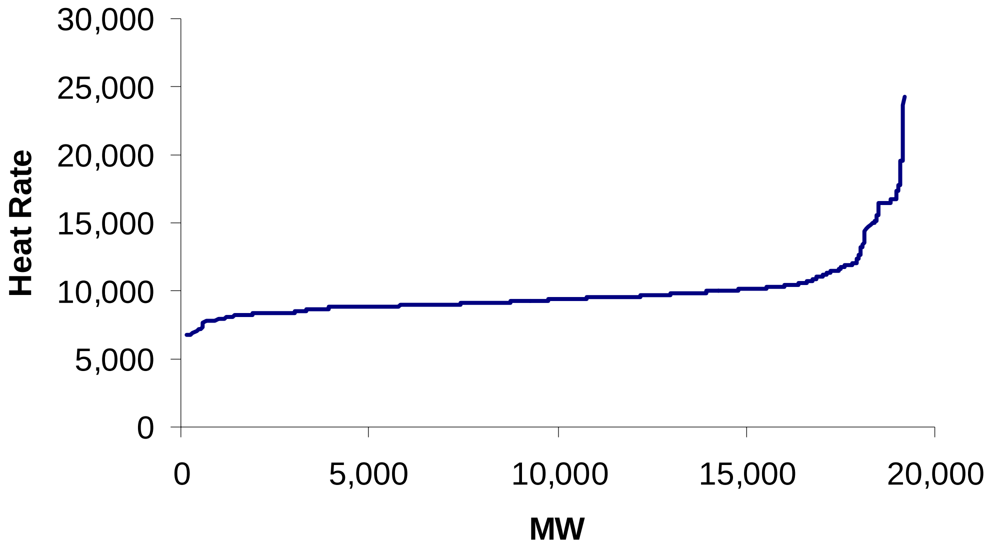
Figures 1 through 5 show how results of the calculations of the highest cost unit actually dispatched in the ISO's real time market have been analyzed in order to assess how such data may be used as a basis for determining refund levels.[1]

- Analysis indicates that when just minor screening is applied to "filter out" the impacts of economic and physical withholding of capacity in the real time market, the marginal cost of energy actually dispatched in the real time market is just slightly above the c*ompetitive baseline level* calculated by the ISO in previous analysis presented to the commission in these proceedings. (see Figures 2-4) Thus, we have included two scenarios in which energy dispatched from the highest cost 1,000 MW of peaking capacity in each hour is screened from the analysis hour unless this energy exceeds a minimum threshold level (50 or 100 MWh). These scenarios are designed to differentiate hours when significant amounts of energy from these units was actually needed to meet system demand, rather than hours when a relatively small amount of gas-fired peaking capacity was dispatched due to zonal or ramping constraints, and/or the economic or physical withholding of lower cost gas-fired capacity. The scenarios provide a quick indication of the potential impact of a more detailed analysis of the amount of high cost generation that could be avoided or displaced by "redispatching" real time energy bids based on the actual cost (rather than bid price) of gas-fired units in the real time market.

- Each of these different scenarios were then also assessed in terms of the total amount of charges that would be refunded if the hourly price resulting from each scenario (representing the cost of the highest cost gas unit dispatched or needed to meet demand) were used as a basis for determining refund levels.

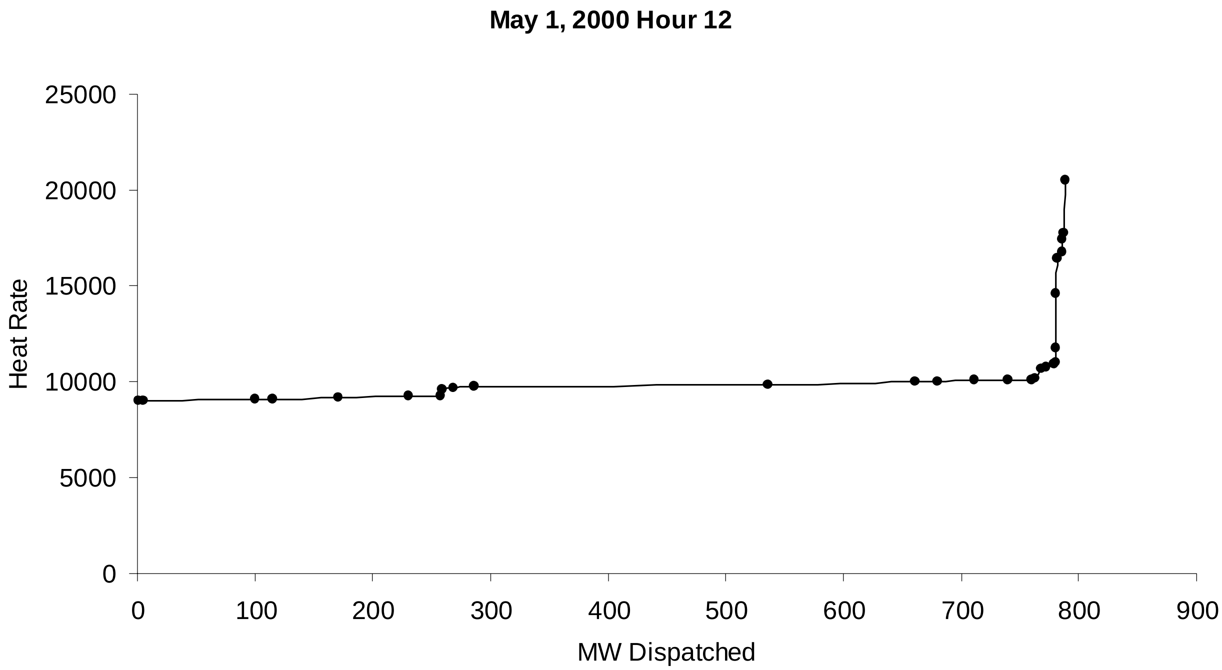
[1] Initial calculations indicate that during about 60% of hours from May 200 to May 2001, the unit with the highest reported heat rate dispatched in the ISO's real time market was a single 25 MW cogeneration (see Figure 3 and 4). Subsequent analysis of this unit indicates that the actual heat rate of this unit is 9,500. Thus, we have revised our analysis with this new heat rate. A description of the engineering analysis performed to assess the actual heat rate of this unit at different operating points will be provided under separate cover.

Figure 1. Incremental Heat Rates of Gas-Fired Generation in ISO System



The bulk of the approximately 19,000 MW of gas-fired generation in the ISO system (93%) has a heat rate of less than 12,000 MBtu. In the absence of the economic or physical withholding of lower cost capacity, units with heat rates above this level would be needed only during periods of extremely high peak demand or for short intervals of time to meet short term energy imbalances. Results of analysis presented in this report show that relatively minor amount of higher cost units have been dispatched during many hours. However, the preliminary analysis presented in this report shows when just minor screening is applied to "filter out" the impacts of economic and physical withholding of capacity in the real time market, the marginal cost of energy actually dispatched in the real time market is just slightly above the c*ompetitive baseline level* calculated by the ISO in previous analysis presented to the commission in these proceedings.

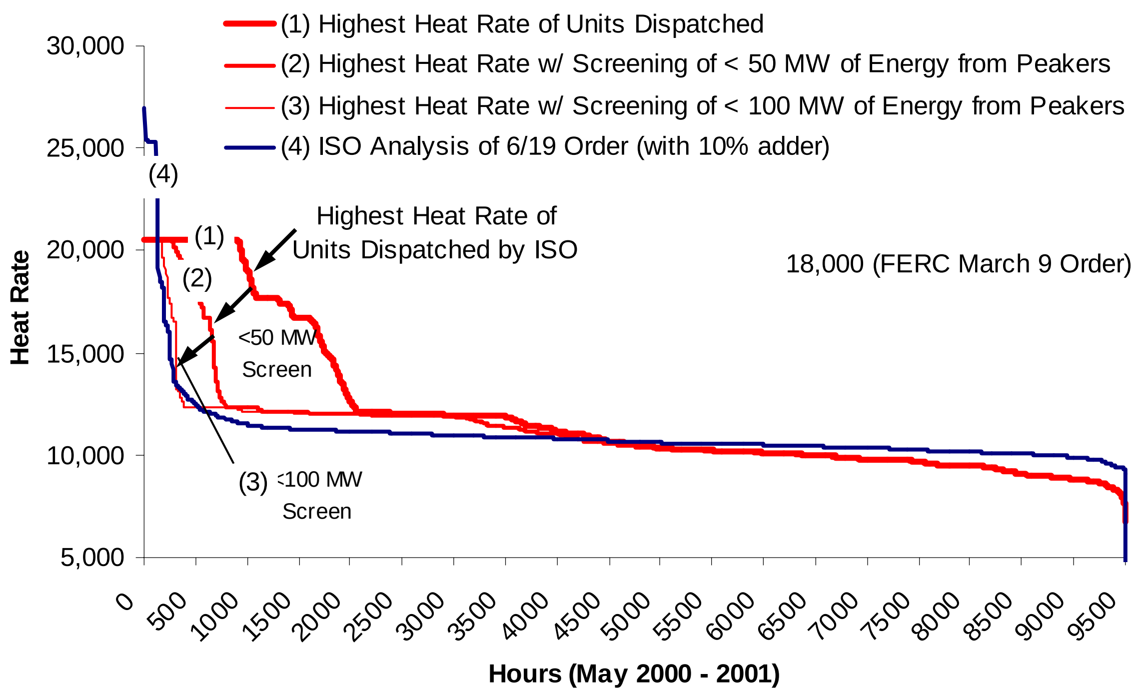
Figure 2. Incremental Heat Rates of Gas-Fired Generation Dispatched in Real Time Market



The chart above shows how filtering out even a small amount of gas-fired generation dispatched to meet demand dramatically reduces results of the analysis presented in this report. The above example was drawn from the first day covered in the analysis (May 1, 2000). During hour 12 of this day, 788 MWh of gas-fired generation was dispatched. About 780 MW of this gas-fired capacity had a heat rate of less than 12,000 or less. However, about 9 MW of high cost peaking units were dispatched, with a maximum heat rate of over 20,000 MBtu.

A similar pattern was found during many hours covered in this analysis. During such hours, a simulation how actual available gas-fired generation would have been dispatched if bid at near actual cost shows that the actual marginal cost of meeting demand would be roughly half of the 20,000 MBtu heat rate of the unit actually dispatched.

Figure 3. Incremental Heat Rates of Gas-Fired Generation Dispatched in Real Time Market (May 2000-May 2001)



The chart above shows how results change when even a small amount of gas-fired generation dispatched to meet demand is "filtered out" of the analysis to reflect the degree to which higher cost capacity may have been displaced if generation was dispatched in true merit order (based on cost), in the absence of economic or physical withholding.

Second, up to 100 MW of real time energy dispatched from the highest cost 1,000 of peaking capacity in each hour were screened from the analysis. The screening was preformed by summing up the real time energy dispatched from the 1,000 MW of gas-fired turbines listed in Attachment A, and then screening out up to 100 MW of energy dispatched from these units.

This scenario is designed to differentiate hours when significant amounts of energy from these units was actually needed to meet system demand, rather than hours when a relatively small amount of gas-fired peaking capacity was dispatched due to zonal or ramping constraints, and/or the economic or physical withholding of lower cost gas-fired capacity. The scenario provides a quick indication of the potential impact of a more detailed analysis of the amount of high cost generation that could be avoided or displaced by "redispatching" real time energy bids based on the actual cost (rather than bid price) of gas-fired units in the real time market.

As shown by this screening analysis, "displacing" up to just 100 MW of energy that was actually dispatched from these 1,000 MW of high cost capacity results in hourly system marginal costs just slightly above the competitive baseline level calculated by the ISO based on actual overall system load and supply conditions.

Figure 4. Incremental Heat Rates of Gas-Fired Generation Dispatched in Real Time Market (May 2000-May 2001)