REPORT ON IMPACTS OF RMR CONTRACTS ON MARKET PERFORMANCE

Prepared by

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EXECUTIVE SUMMARY

The ISO's Market Surveillance Committee (MSC), in its August 19, 1998 report to FERC, expressed concerns that RMR contracts are providing incentives for RMR units to withhold their capacity from the Day Ahead energy market. The ISO Market Surveillance Unit (MSU) has conducted an independent investigation of the impacts of the RMR contracts and presents the results in this report. Throughout this report, we define withholding to include withholding or strategic bidding of capacity from RMR units, which results in capacity that could have been profitably cleared the Day Ahead PX market not being scheduled in the Day Ahead energy market, or any of the subsequent energy and ancillary service markets. In a competitive market, free from market distortions, suppliers can be expected to maximize revenues by fully utilizing capacity in these different markets.

Generation owners can benefit from withholding or strategic bidding of capacity from RMR units in two ways. First, the generator may anticipate being called under RMR Contract A and receiving revenue from a reliability capacity payment in excess of what it would receive if it bid into the Day Ahead energy market. Second, by withholding capacity from the market, the generator may be able to influence the clearing price and thus receive a higher price for all other units in the owner's portfolio.

The ability to receive an above-market reliability payment exists primarily under Contract A. The ability to influence market clearing prices and receive higher prices for non-RMR units in an owner's portfolio (the portfolio effect) exists for units under either contract, but much more so for units under Contract B. Currently, Contract B requires a generator to return 90% of its market profit to the ISO. Therefore, when a generator withholds an RMR unit, its loss of opportunity for that unit is only 10% of market profit, while the remainder of their portfolio will benefit from a higher market clearing price. We view this as rational and expected profit-maximizing behavior on the part of generators given the current incentives present under RMR contracts and their utilization by the ISO.

A second way in which RMR contracts distort California's energy market results from the current practice of dispatching RMR units after the PX Day Ahead market. This market design ignores the fact that this generation must run and ultimately will be used to meet demand, and results in excess supply being purchased in the day ahead market. Purchasing this excess supply, in turn, increases the PX price, by artificially inflating demand with the inclusion of load that must ultimately be met by RMR generation. This creates unnecessary market inefficiencies, and requires that consumers pay twice for the local reliability provided by RMR units: once through direct fixed cost payments to generators, and again through higher market prices. Although this report focuses primarily on the impacts of current RMR contracts in terms of withholding or strategic bidding of capacity in the PX market, one of the key recommendations of the report is that RMR generation should be effectively "netted out" of market demand prior to the Day Ahead market, in order to allow all remaining supply and demand to be balanced in the most economically efficient manner through the subsequent energy markets of the PX and ISO.

Study Description

This report focuses primarily on the impacts of current RMR contracts in terms of withholding or strategic bidding of capacity in the PX market. However, it is important to note that features of current RMR contracts, such as the requirement that 90% of market revenues be credited back under Contract B, also facilitate withholding or strategic bidding of capacity in the ISO's markets for ancillary services and real time imbalance energy. In addition, even in the absence of RMR contracts, suppliers with market power can benefit from withholding or strategic bidding of capacity in all of these markets. In quantifying the magnitude of potential impacts from withholding or strategic bidding of capacity from RMR units, we have focused primarily on the impacts in the PX market since these impacts are likely to be the most significant to consumers and to decisions regarding negotiation of revised RMR contracts.

To address concerns that current RMR contracts create or increase incentives to withhold capacity (or bid less competitively) in day-ahead markets, we compared market participation by units under RMR contracts to the level of market participation that could be expected under competitive conditions. Our assessment of when units would could be expected to participate in the market under competitive market conditions is based on when it would be profitable for units to be operating based on unit operating costs and prices in the Day Ahead PX market. In assessing the actual market participation of RMR units, we accounted for the ability of suppliers to maximize profits by arbitraging between different energy and ancillary service markets by defining actual market participation to include all capacity that is scheduled in the Day Ahead energy market, as well as the ISO's ancillary service and supplemental real time energy markets

For the period May to October, 1998, we estimate the overall participation in energy markets by units under Contract A to be about 23% to 29% lower than would be expected given the actual market prices and projected operating costs of these units. Over these same months, participation in energy markets by units under Contract B appears to be about 30% lower than would be expected in a fully competitive market. When pooled together, we found participation in day ahead markets by all RMR units to be about 27% to 29% lower than would be expected in a highly competitive market.

Withholding or strategic bidding of capacity from RMR units can also increase the amount of additional energy the ISO needs to schedule under RMR in order to meet minimum reliability requirements. Based on the analysis of withholding summarized in this report, we estimate these direct costs to be approximately $21 million over the 6-month period from May to October 1998.

Withholding or strategic bidding of capacity from RMR units also impacts energy costs indirectly by decreasing the supply of energy bid into the day-ahead PX market, thereby increasing the market-clearing price for all energy purchased in the day-ahead market. Using hourly ISO and PX schedule and bid data for the 4-month period from June to September 1998, we estimate these potential indirect costs in the entire PX market to be as high as $272 to $313 million.

Discussion of Results

Results of this analysis should be viewed as providing an indication of the potential magnitude of impacts of withholding or strategic bidding of capacity from RMR units in 1998 and in future years. During the 1998 summer peak, the market was in its very formative stage. Owners of generation resources were just beginning to test the market. The overall markets impacts assessed in this report represent the cumulative effect of bidding and scheduling decisions made by many different market participants.

However, the lessons learned will not be lost on 1999 market participants. In 1998, a large portion of generation resources were still owned by the state's IOU's who, as net buyers of generation, may face mixed incentives in terms of how to utilize their generation resources in the market. In future years, a much larger portion of generation resources will be owned by new entities who can be expected, understandably, to exploit fully the profit potential inherent in the "A" and "B" contract structures. Whether or not these bidding strategies were used in 1998, it cannot be assumed that they will be ignored during the 1999 peak period.

For purposes of considering the benefits of modifying RMR contracts, we believe it is not necessary to fix the amount of the cost increase beyond the level of precision of the analysis in this study. Whatever the amount, whether it be $100 million or $500 million, it is in the best interest of California that the focus now be on the modifying RMR contracts to ensure a workably competitive market in the peak period of 1999.

Due to the ability of supplier and buyers to arbitrage between the Day Ahead and real time markets, the change in PX price resulting from the withholding or strategic bidding of capacity that is quantified in this report could be offset in part by a shifting of demand from the Day Ahead Market to the real time market. To the extent this occurred, however, significant negative market impacts would nevertheless result from the withholding or strategic bidding of capacity from RMR units. Increased (and often unpredictable) demand in the real time markets increases the overall volatility of prices, and the costs associated with insuring against the effects of demand uncertainty on system reliability. The ISO is implementing a wide range of modifications to its current protocols to discourage under scheduling of load in the Day Ahead market, and to decrease reliance on the real time imbalance market. During the next peak summer season, these modifications will hamper the extent to which demand can simply respond to high prices in the Day Ahead PX market by shifting demand into the real time market.

In addition, as previously noted, the definition of market participation used in this analysis included all capacity that cleared either the PX energy market, or the ISO's ancillary service and real time markets. Results of the analysis indicate that a significant amount of capacity from RMR units which could have profitably cleared by Day Ahead PX market was not merely shifted to subsequent energy and ancillary service markets, but was withheld from all these different markets. Thus, even if a portion of the effects of withholding or strategic bidding of capacity from RMR units may be offset in a shift in demand to the real time energy market, withholding or strategic bidding of capacity from RMR units has the effect of increasing prices in all these different markets.

Finally, it is important to note that the overall market impacts of withholding or strategic bidding of RMR capacity that are quantified in this report are distributed among different market participants, which include both investor owned utilities and new generation owners (NGOs). In 1998, for instance, we estimate NGO's accounted for less than 10% of total energy sales and only about 13% of total gross revenues in the PX market. The ultimate effect on and profits of suppliers, and costs to consumers depends on the market share of different suppliers, as well as the degree to which increased costs of supply are ultimately passed on to consumers.

Recommendations

The Market Surveillance Unit (MSU) recommends three modifications based upon fundamental economic principles that it believes would significantly correct the RMR-contract incentive problems. The MSU considers these fundamental principles to be essential for the proper functioning of RMR contracts in a competitive, efficient market:

1. Declaring RMR dispatch before the day-ahead market.
2. Treating the pre-market dispatched portion of RMR generation as "must-take" in the Day Ahead energy market.
3. Separating the bidding incentive from the payment mechanism. This can be accomplished by basing compensation paid to RMR owners primarily on an up front payment for the option to call them under for reliability RMR.

The first modification would effectively remove the generator's incentive to withhold from the market to receive a potentially higher RMR price under Contract A, since the RMR generation requirements would be known before bids to the day-ahead market were developed. The modification is also necessary in order for RMR generation requirements to be "netted out" of the Day Ahead market, as discussed below.

The second change recognizes the fact that the RMR generation requirement must be satisfied and accepted by the system for reliability purposes. The selection of RMR generation is not a function of price but rather a function of the system reliability requirements. Thus, the portion of RMR generation needed for grid reliability is in fact "must take" in the same sense that nuclear power is considered must-take, and should be bid accordingly.

The third proposed modification ensures that the pricing for the regulated RMR generation is separate and independent from the pricing for the unregulated energy market. The intent of this principle is to facilitate obtaining the necessary reliability services without adversely impacting the competitiveness and efficiency of the remaining energy market.

In summary, the California ISO Market Surveillance Unit agrees with the Market Surveillance Committee that the current RMR contract mechanism provides incentives to generation owners to either withhold, or price at higher than competitive levels, capacity into the day-ahead markets. This incentive results in higher energy costs to the California consumer. The MSU recommends the corrective actions outlined above and firmly believes that incorporating these fundamental principles in RMR contract design and utilization will result in a more competitive and efficient energy marketplace.

Professor Robert Wilson of Stanford University, consultant to the ISO on market design issues, has expressed an opinion on the MSU recommendation, which is included as Appendix A of this report.

The MSC has provided a summary opinion regarding revision of the RMR contracts, which is included as Appendix B. The full report of the MSC is being submitted under separate cover.

1. INTRODUCTION

Market Surveillance Unit (MSU) Role

The MSU is charged with investigating and analyzing any bidding behavior that may impact overall market performance. Because it appeared that the use and behavior of RMR units were impacting overall market performance, the Market Surveillance Unit and the Market Surveillance Committee undertook separate and independent studies of the contract structures and empirical market data.

Problem Statement

Our examination of the contract structures led us to believe that we could expect the following problems:

<u>Current Contract A: (MWh based reliability payment when capacity is called by ISO)</u>

- The reliability payment based on MWh generation creates an incentive to withhold in order to earn the RMR payment when it is higher than the market price.

- For owners with a large portfolio of non-RMR units, withholding RMR units can increase the market clearing price. They would receive increased revenue from their non-RMR portfolio.

<u>Current Contract B: (100% of fixed cost paid, and 90% market profit is returned to ISO)</u>

- The portfolio effect described above exists for contract B, but with even stronger incentives.

- In looking at the cost compared to the benefits gained from withholding, the cost is small since units under Contract B keep only 10% of the normal market profit, while the benefit for their portfolio in withholding may be higher market prices for the remaining units.

This behavior increases the costs the ISO pays for RMR services. As a result of generators under Contract A withholding, the ISO is forced to call RMR units during times the unit should normally have bid into the market, and pay them the higher contract price. This is a direct cost to the market. A second, and more serious consequence for market performance, is the indirect cost of this withholding behavior. These RMR generators, either by withholding or bidding prices higher than their marginal costs can cause PX prices to be higher than if the RMR units would bid competitively with the intent of being selected.

The following example illustrates how different RMR contracts can create incentives for generators to withhold capacity from the day-ahead market in order to increase net profit.

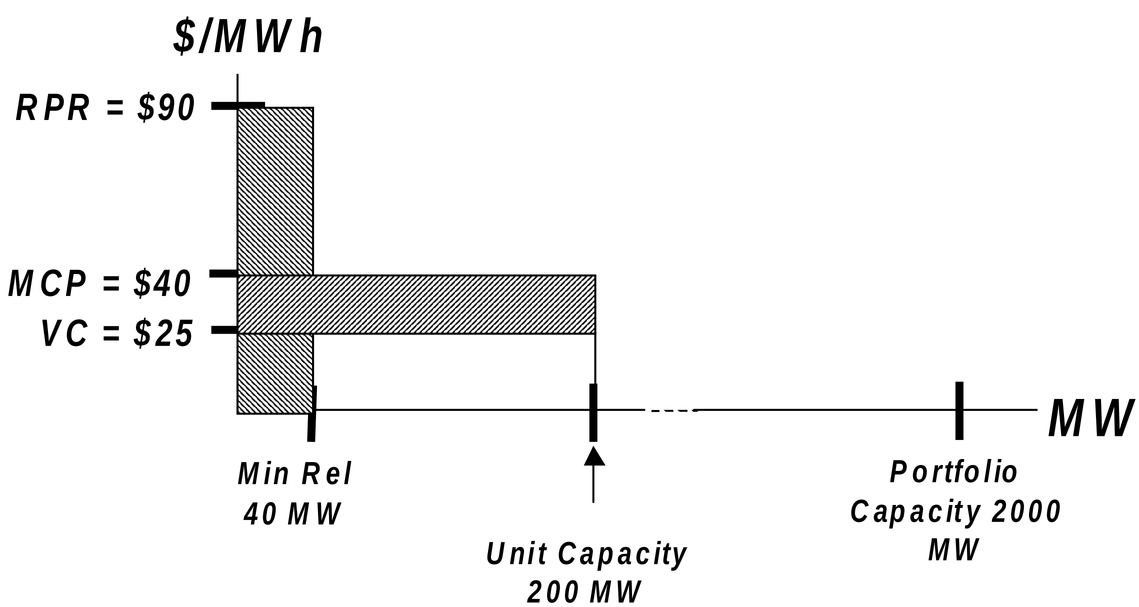
Illustrative Example:

Assume an Owner has a generation portfolio of 2,000 MW including a 200 MW RMR unit. The variable cost (VC) of this RMR unit is $25/MWh, and when under Contract A, its Reliability Payment Rate (RPR) is $90/MWh. Under Contract B, with all fixed cost paid, the RMR unit would be required to pay back 90% of its market profit. The minimum reliability level (MW) the RMR unit is needed is 40MW. The other units in the portfolio would clear the day-ahead market.

The day-ahead energy market clearing price (MCP) is $40/MWh when the RMR unit participates in the market by bidding competitively. Assume that by withholding this RMR unit the MCP would increase by $1/MWh (from $40/MWh to $41/MWh).

As the following figure illustrates, under Contract A, the unit would forego a potential profit of $3,000 (i.e., ($40-$25)*200MW) by not participating in the day-ahead energy market. In return it would be paid a net of $3,600 (i.e., $90* 40MW) if called under RMR after the day-ahead market. This is a direct gain attributable to the RPR incentive created by Contract A. In addition, to this direct net gain of $600 (i.e., $3,600-$3,000), the rest of the Owner's portfolio would have an additional profit of $1,800 (i.e., $1*(2,000MW-200MW)).

If this unit were under Contract B (with all its fixed cost paid and only 10% of market profit retained), the unit would forego a potential profit of $300 (i.e., ($40-$25)*200MW*10%) by not participating in the day-ahead energy market. In return, the rest of the Owner's portfolio would have an additional profit of $1,800 (i.e., $1*(2,000MW-200MW)), for a net overall increased profit of $1,500.



Report Structure

Following this introductory section, we provide a detailed empirical analysis of market performance under RMR Contracts in Section 2. Section 3 outlines several design principles which we feel are essential to remedy the problems with the existing contracts. Section 4 presents the main conclusions and recommendations.

Appendix A presents the opinion of Professor Robert Wilson of Stanford University, consultant to the MSU on market design issues. Appendix B presents a summary opinion of the Market Surveillance Committee containing recommendations for revising RMR contracts. The details of the methodology used in the MSU's analysis are presented in Appendix C.

2. MARKET PERFORMANCE UNDER CURRENT RMR CONTRACTS

2.1 METHODOLOGY

Empirical Investigation

To investigate the actual impact of these structural disincentives to competitively bidding which are inherent in the current RMR contract structures, the MSU conducted empirical analysis of ISO and PX market operation data from the period May 1998 to October 1998. We believe there is clear evidence of withholding and the impact on market efficiency has been significant.

Analysis of Withholding of Capacity from Day Ahead Markets

In this analysis, we compared the following data on the actual participation of RMR units in different energy and ancillary service markets:

1. Energy schedules that could be expected for different hours of a day based on each unit's marginal operating costs, start-up costs, and actual market clearing prices in the PX. Throughout this analysis, we refer to this expected energy schedule as the Economic MWh for each unit during each hour. This is the minimum amount of capacity we would expect to be scheduled in different energy and capacity markets under competitive conditions, profit maximizing behavior, and no distortion of marginal incentives from RMR contracts.

2. The actual Day Ahead energy, ancillary service and real time energy schedules for units under RMR contracts. The sum of capacity from each unit scheduled in each of these different markets represents the measure of total market participation used in this analysis. This approach was used to account for the ability of suppliers to arbitrage between different markets which clear after the PX Day Ahead market, as discussed in more detail below.

In a competitive market, suppliers can be expected to seek to maximize profits by arbitraging between opportunities to utilize supply capacity in different markets, which include the day ahead energy market, ancillary service markets, and the supplemental real time energy market. Due to the sequential nature of these markets, suppliers may bid into each market based on their estimated profits in subsequent markets, which represent the true marginal or opportunity cost to suppliers if their bids are accepted in previous markets. For instance, a supplier can be expected to bid capacity into the Day Ahead PX market at levels such that, if accepted in the Day Ahead energy market, this capacity would yield profits that are comparable to those that could have been earned if the capacity instead cleared in the ancillary services or supplemental energy markets.

However, it is important to note that if capacity it bid into the PX based on the perceived opportunity cost of capacity in subsequent markets, suppliers profits can only be maximized by then bidding any capacity that does not clear the PX more aggressively in subsequent markets to ensure that this capacity clears in these markets. In the absence of market power (defined as the ability to set market prices by withholding or strategic bidding of capacity), capacity which fails to clear in subsequent markets yields no revenues for suppliers. Thus, in the absence of market power, such "opportunity cost" bidding in the PX only maximizes revenues if all capacity which could have cleared the PX clears in a subsequent market.

In order to account for suppliers' ability to arbitrage between different markets which clear after the PX Day Ahead market, the measure of market participation used in this analysis was defined as including all capacity scheduled in the Day Ahead energy, ancillary service and supplemental real time energy markets. This measure of actual market participation was compared to the amount of capacity that could be expected to be in the market, based on each unit's variable operating costs and energy prices in the Day Ahead energy market. We estimated potential withholding of capacity from the day-ahead market due to incentives for capacity withholding or strategic portfolio bidding created by RMR contracts by calculating the difference between the economic MWh for each unit during each hour, and each unit's actual energy schedule (plus any ancillary service capacity provided). A more detailed description of the methodology used in this analysis is provided in Appendix C.

In determining the Economic MWh for each unit during each operating hour, we paid careful attention to how start-up decisions are made and how start-up costs affect when it is economic for units to participate in the market. We assume units with start-up times of less than two hours to have a new start-up every day that they are scheduled. We assumed units with start-up times over 2 hours to start-up only at the beginning of periods (lasting one or more days in duration) when operating revenues would be sufficient to cover start-up costs. Once a unit starts up, we assumed it to continue operating each day as long as net daily revenues (market revenues minus variable operating costs) are positive. A more detailed description of the methodology used to identify days when it would be economic for units to be participating in energy markets is provided in Attachment C.

We believe our analysis is based on conservative assumptions in defining days when would be profitable for units to start up and be participating in the market under fully competitive market conditions without any distortions created by RMR contracts. For instance, the analysis assumes every start-up has to be a profitable decision based solely on these energy revenues. In real markets, there is no such guarantee that all start-ups will be profitable, and generators may often start-up based on merely the expectation that start-up costs will be covered by subsequent revenues as actual market conditions unfold. In addition, potential revenues for ancillary services when units are on-line but not operating at full capacity are not factored into the decision to start up or continue operating a unit. These revenues from ancillary services can provide a major source of additional revenues for RMR units, particularly those with higher variable operating costs.

In order to provide results under another conservative assumption, we also calculated a second case which uses the same basic definition of withholding described above, but assumes that no capacity withholding for units under contract A during hours when a unit's Minimum Reliability Requirement is greater than zero, and the unit's day ahead energy schedule is greater than this requirement. In these hours, no change in the unit's day ahead schedule was necessary to meet RMR requirements. This case is designed to exclude cases when it is apparent that capacity was not withheld from the day ahead energy market specifically to receive reliability payments for energy called by the ISO under Contract A. This is conservative because it would have been profitable to produce at full capacity but the unit was producing less. This type of withholding can be attributed to other market imperfections, but we did not attribute it to withholding due to RMR contract incentives.

Table 2-1 summarizes our results for both of the cases, or definitions of withholding, described above. For the period May through October, we found an overall *withholding rate* for RMR units under Contract A of about 34%. Under Case 2, which is designed to assess withholding that may be more directly attributable to incentives created by reliability payments received under Contract A, withholding is estimated at about 23% of total economic MWh. For units under Contract B, the overall *withholding rate* was about 28%.

During the months of May to October, the percentage of economic capacity withheld decreased, while the quantity of this capacity withheld was highest during the peak summer months. Several potential explanations for this trend are:

- Changes have occurred in the ancillary services market. In spring, all units were subject to FERC cost based rates for ancillary services. The ISO frequently had to call upon the RMR units to remedy the bid insufficiency in the ancillary services markets. By withholding from the day-ahead energy or ancillary services markets even when it would have been economic to participate in these markets, the unit could receive a large reliability payment to be scheduled at its minimum operating point if needed for ancillary services. In the summer, when market based rates were granted for some RMR units, the incentive to withhold capacity in anticipation of calls for ancillary services may have been reduced. This incentive was practically eliminated in November when all units were granted market-based rates.
- Owners of generation units under RMR contracts have indicated that, until about July or August, they had not developed well defined bidding and scheduling procedures to ensure the most efficient use of all capacity under their ownership.

We found the average withholding rate of RMR units under Contract A to be generally higher than for units under Contract B during all months until October. We attribute the increase in withholding for units under Contract B to a number of large units, which switched from Contract A to Contract B starting in October.

Table 2-1. Estimated Withholding of Economic Capacity From Day Ahead Markets

		Case 1		Case 2	
		All Economic MWh		**Excludes MWh Withheld by Units under Contract A When Final Energy Schedule > RMR Reliability Requirement**	
	Economic MWh	MWh Withheld	Percent Withheld	MWh Withheld	Percent Withheld
Units Under Contract A					
May	42,940	16,654	39%	16,576	39%
June	181,827	55,903	31%	52,431	29%
July	1,805,546	609,477	34%	517,313	29%
Aug	2,589,520	687,253	27%	510,779	20%
Sept	1,486,430	458,468	31%	345,589	23%
Oct	249,255	24,151	10%	12,559	5%
Sub-Totals	**6,130,751**	**1,779,350**	**29%**	**1,386,241**	**23%**
Units Under Contract B					
July	2,218,671	575,681	26%		
Aug	2,618,418	511,162	20%	Same as Case 1	
Sept	1,969,812	469,436	24%		
Oct	2,127,746	1,085,551	51%		
Sub-Totals	**8,934,647**	**2,641,830**	**30%**		
Totals	**15,065,398**	**4,421,180**	**29%**	**4,028,071**	**27%**

Table 2-1 summarizes estimated withholding of economic capacity from day ahead markets by month for all RMR units under Contract A and Contract B. The column labeled *Economic MWh* shows the total number of MWh that our analysis indicates would have been economic for generators to bid into the day ahead energy market (at prices lower than the actual PX market clearing price). The column labeled *MWh Withheld* represents the portion of this economic energy that was not scheduled in the day ahead energy market, ancillary service markets, or real time imbalance market.

For Case 1, the amount of *MWh Withheld* is calculated on a unit-by-unit, hour-by-hour basis using the following equation: *Economic Energy (MWh) - Day Ahead Energy Schedule (MWh) – Ancillary Service Schedule (MW) – Real Time Energy Schedule (MWh)*. Case 1 is designed to capture withholding due to both RMR reliability payments and the overall effect of strategic portfolio bidding that is facilitated by RMR contracts. Case 2 uses this same equation, but assumes no capacity withholding for units under contract A during hours when a unit's Minimum Reliability Requirement is greater than zero, and the unit's day ahead energy schedule is greater than this requirement, so that no change in the unit's day ahead schedule was necessary to meet RMR requirements. This case is designed to represent a more conservative estimate of withholding, which excludes cases when it is apparent that capacity was not withheld from the day ahead energy market specifically to receive reliability payments for energy called by the ISO under Contract A. In both cases, *MWh Withheld* is zero for hours when *Economic Energy (MWh) < Day Ahead Energy Schedule (MWh) + Ancillary Service (MW) + Real Time Energy Schedule (MWh)*.

Direct Costs of Capacity Withholding

Withholding of capacity from the PX market directly effects costs by increasing the amount of additional energy the ISO needs to schedule under RMR in order to meet minimum reliability requirements. We calculated these additional direct costs on an hour-by hour-, unit by-unit basis using the additional energy the ISO needed to schedule (if any) due to withholding by each unit, in each hour.[1]

Table 2-2 summarizes the estimated direct financial impacts of withholding separately for units under Contract A and Contract B. As shown in Table 1-2, we estimate the total direct impacts from increased RMR payments to be about $21 million for the 6-month period May through October 1998.

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[1] For hours in which our analysis indicates it would have been economic for a unit to be operating through the day ahead energy market, the increase in energy scheduled to meet Minimum Reliability Requirements due to this withholding of capacity for each unit in each hour is equal to:

MWh_Called = RMR Requirement by ISO(MWh) – Energy Scheduled (if >0, 0 otherwise).

The net direct cost of this increase in energy called under RMR contracts for each unit under Contract A in each hour was calculated using the following equation:

Added_Cost_Per_MWh = (Reliability Payment per MWh + Variable Operating Cost per MWh + Contract *Pro Rata* Start-up Payment per MWh) - Real Time Imbalance Price

For Contract B, only the Variable Operating Cost Contract plus *Pro Rata* Start-up Payment per MWh)was used. The total direct cost for each unit in each hour is therefore the product of MWh_Called and Added_Cost_Per_MWh.

Table 2-2. Direct Costs of Estimated Withholding of Economic Capacity From PX Day Ahead Energy Market

	Minimum Reliability Requirement (MWh) *	RMR Schedule Change (MWh) *	Schedule Change to Dispatch Economic MWh	% Schedule Change to Dispatch Economic MWh	Additional Direct Costs
Units Under Contract A					
May	986,754	831,352	7,691	1%	$ 233,237
June	1,052,644	771,191	13,069	2%	$ 601,108
July	872,777	357,840	168,670	47%	$ 6,396,179
Aug	1,055,544	417,359	207,658	50%	$ 7,338,479
Sept	711,419	264,470	74,138	28%	$ 2,242,334
Oct	341,830	9,003	399	4%	$ 27,837
Sub-Totals	5,020,968	2,651,215	471,626	18%	$16,839,174
Units Under Contract B					
July	708,539	82,554	43,306	52%	$ 1,660,237
Aug	782,489	38,653	23,705	61%	$ 1,077,527
Sept	658,597	70,147	45,556	65%	$ 1,285,125
Oct	446,647	125,225	16,295	13%	$ 714,595
Sub-Totals	2,596,272	316,579	128,862	41%	$ 4,737,485
Totals	**7,617,240**	**2,967,794**	**600,488**	**20%**	**$ 21,576,659**

* Minimum Reliability Requirements and Schedule Changes for all RMR units.

Table 2-2 summarizes direct costs of withholding or strategic bidding of capacity from RMR units, in terms of additional amount of RMR payments made by the ISO for energy from units that would have been economic to schedule in the day ahead energy market (based on unit operating costs and market clearing prices in the PX). For units under Contract A, RMR payments include operating costs and a reliability payment. For units under Contract B, these direct costs are based only on variable operating costs. As shown in the table above, analysis indicates that a total of about 20% of energy scheduled through all RMR contracts by the ISO after the close of the day ahead market could have economically cleared the day ahead PX market. During the peak summer months of July through September, nearly half of generation schedule changes issued by the ISO through all RMR contracts could have economically cleared the day ahead PX market.

Indirect Costs of Withholding

Withholding of capacity from the PX market also effects costs indirectly by decreasing the supply of energy bid into the day ahead PX market. In our preliminary analysis, we estimated these direct impacts by combining result of our analysis of capacity that could have been economically bid into day ahead markets with a regression model of market clearing prices and quantities in the PX market for each month. This approach is illustrated in more detail in Appendix C.

For this report, we use a similar approach, but estimate the indirect impacts of withholding on day ahead energy prices using actual supply and demand bid segments for each hour provided by the PX. With this approach, results of our analysis of capacity withheld from the day ahead markets that could have economically cleared the PX market were used to generate additional "bid segments", representing additional supply that would have been available to different price levels. The market clearing price in the PX was then recalculated with these additional supply bid segments added to actual bid segments submitted to the PX. The increase in PX price due to withholding of this additional capacity was then calculated based on the difference in the PX price with and without these additional bid segments. Indirect costs were calculated by multiplying the change in PX price by the actual market clearing quantity in each hour. The figure below depicts how this change in the PX market clearing price is calculated based on a shift in the supply curve during each hour.

The PX Market

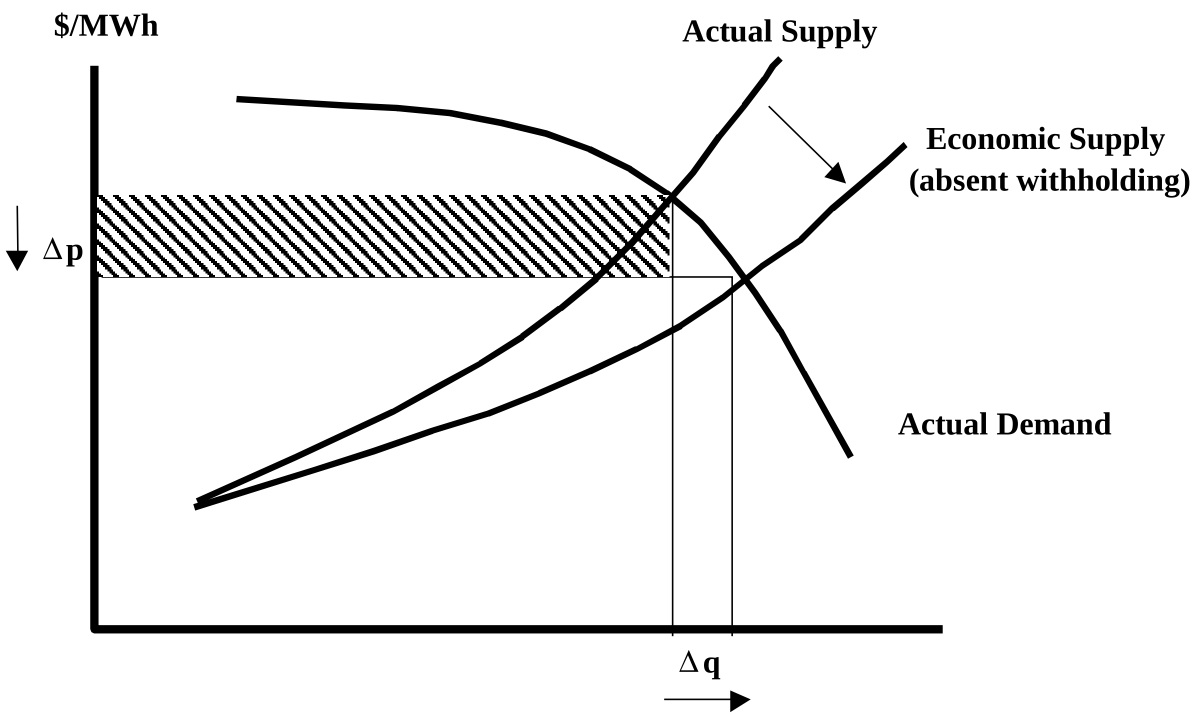


Table 2-3 summarizes our estimates of combined indirect financial impacts of withholding for units under Contract A and Contract B. Under the broadest definition of witholding used in Case 1, total indirect impacts from total withholding by RMR units are estimated at about $313 million for the 4-month period June through September 1998. Under the definition of withholding used in Case 2, which excludes hours when units were scheduled a level high enough to meet minimum reliability requirements (but lower than their economic capacity), indirect impacts in the PX market are about $272 million.

Table 2-3. Potential Indirect Costs of Withholding of Economic Capacity From PX Day Ahead Energy Market

	Case 1 **All Economic Hours**	**Case 2** **Excludes Units under Contract A When Final Energy Schedule > RMR Reliability Requirement**
Units Under Contract A & B		
June	$ 3,937,303	$ 3,891,245
July	$115,133,838	$108,256,217
Aug	$145,024,232	$124,966,081
Sept	$ 49,124,735	$ 35,013,978
Totals	$313,220,108	$272,127,521

Table 2-3 summarizes the indirect cost of capacity withheld from the day ahead energy market in terms of increased costs in the PX. These indirect costs were calculated on an hour-by-hour basis by combining estimates of the amount of capacity withheld by shown in Table 2-1, with actual supply and demand bids in the PX. Increased costs in the PX were calculated by multiplying the actual market clearing quantity in the PX each hour by the decrease in the market clearing price that would have resulted if all economic capacity from RMR units had been bid into the PX market. As described above, the amount of capacity and energy that cleared the subsequent ancillary service and supplemental real time markets was subtracted from the amount of capacity from RMR units used in this analysis. The analysis simulated prices that would result if RMR capacity not clearing any of these markets had been bid into the PX. In this analysis, each unit's full operating capacity was assumed to be bid into the PX at it's variable operating costs during hours when the actual PX price exceeded the units variable operating cost. PX demand and supply bid data were only available for June through September.

2.2 COMPARISON WITH PREVIOUS ANALYSIS

The analysis presented in this report represent a revised version of an earlier analysis presented by the MSU to the Market Surveillance Committee (MSC) and to participants in RMR negotiations in December 1998. Analysis included in this report includes several key changes to address some of the concerns expressed by the generator owners and other participants who have reviewed our earlier analysis.

- In analyzing whether it would be economical for units to start-up and operate for one or more days, the impact of start-up costs is explicitly taken into account. Units are assumed to start-up only when projected revenues from the participation in the Day Ahead energy market for the subsequent seven day period would exceed start-up and variable operating costs. As noted above, this approach is conservative in that additional revenues from ancillary services were not factored into the start-up decision.

- In defining market participation by each generating unit, we have included the amount of capacity clearing the real time energy imbalance market, in addition to the capacity clearing the Day Ahead energy and ancillary services market.

- As noted in the previous section, two different cases, representing different definitions of withholding are used. The first case quantifies withholding as in our previous analysis, based on the difference between an hourly operating schedule which would be economic given each units operating costs and market prices, and amount of energy and capacity actually scheduled in each hour through the day ahead energy and ancillary service markets. A second case is also analyzed which is based on this same definition of withholding, but excludes any unscheduled capacity during hours when a units' energy schedule was high enough to meet the units minimum reliability requirement. This second case is designed to represent a more conservative estimate of withholding *directly* attributable to incentives created by RMR contracts, rather than withholding that may result from the other factors allowing generators to influence market prices through strategic bidding or capacity withholding.

- Revised marginal cost data for geothermal unit were used, and hydro units were screened from the sample due to the difficulty of incorporating the effect of hour to hour variations in available energy into the analysis of the amount of energy that could be profitably produced by these units each hour.

- Revised gas prices were used to calculate unit operating costs, based on monthly gas price data provided by transmission owners for northern and southern California.

- The actual hourly PX supply and demand bids are now used instead of the regression model of the overall market equilibrium price and quantity used in the earlier analysis.

- The direct and indirect costs of withholding have only been calculated for months in which actual operating and PX bid data were available, with no attempt being made to extrapolate from these results to estimate cost impacts on an annualized basis.

2.3 KEY FINDINGS

Key findings of this analysis are summarized below:

1. Withholding of capacity from the day ahead markets is a problem with both Contract A and B. For the period May to October, 1998 the overall participation in day ahead markets (taking actual participation in both the energy and ancillary services) by units under Contract A appears to be about 23% to 29% lower than would be expected given market prices and operating costs of these units. For the 4-month period from July to September, participation in day ahead markets by units under Contract B appears to be about 30% lower than would be expected given market prices and operating costs of these units. The ability to make direct comparisons between results for units under Contract A and Contract B are difficult due to difference in the type of units under each contract, and by the fact that may units switched from one contract to another during the period used in this analysis.

2. The direct cost of capacity withholding to the ISO (the higher RMR payments for energy that could have been economical for generators to schedule through the day ahead energy market) has been approximately $21 million for the 6-month period May through October 1998.

3. The indirect cost of capacity withholding to the PX energy market is estimated at approximately $272 to $313 million for the 4-month period June through September 1998 (the period for which the MSU had actual data on PX supply and demand bids).

4. As shown in Table 2-4, the total potential indirect costs quantified in this study represent about 7% of total gross revenues in the PX market in 1998, and about 11% of gross revenues for the four month period from July to October.

Table 2-4. Potential Indirect Costs of Withholding of Economic Capacity Compared to Total PX Day Ahead Energy Market

Month	Total PX Costs*	MWH	$/MWh	Potential Indirect Impacts (as percent of PX costs)	
April	$333,854,802	14,318,066	$23.32		
May	$177,103,791	14,173,289	$12.50		
June	$204,210,450	15,406,313	$13.25		
July	$672,177,957	18,892,642	$35.58	$3,891,245	1%
Aug	$836,426,447	19,269,236	$43.41	$108,256,217	13%
Sept	$633,034,527	17,129,914	$36.95	$124,966,081	20%
Oct	$429,677,062	15,750,747	$27.28	$35,013,978	8%
Nov	$402,756,647	15,411,989	$26.13		
Dec	$478,628,734	15,966,510	$29.98		
Total	$4,167,870,416	146,318,707	$28.48	$272,127,521	7%
July-Oct	$2,571,315,992	71,042,540	$36.19	$272,127,521	11%

* Based on unadjusted MCP x MCQ.

3. RMR DESIGN PRINCIPLES

There are several economic principles key to correcting the incentive problems created by the RMR contracts:

1. *Principle of the separation of Grid Operation from the Energy market.*

   Acquiring the RMR service should not impact the energy market performance. Current RMR operation impacts the energy market performance since the dispatch of additional RMR capacity after the Day Ahead market creates imbalanced schedules and over generation. This over-generation depresses the real-time energy price and attracts demand from Day Ahead market into real-time, causing the real- time market to take up part of the energy market trading. This means RMR dispatch is actively influencing the energy markets. Dispatching RMR before the Day Ahead market and treating RMR dispatch energy as must take is key to implementing this principle of separation of RMR from the energy markets.

2. *Principle of protecting competitive energy market.*

   RMR operation and the energy byproduct are purchased outside the market, via contracts, to mitigate locational market power. RMR operation should isolate contracted reliability service from the much larger competitive part of the energy market. RMR contracts should not change a generator's incentive to bid in the market through RMR contracts. When contracts and bidding behavior are linked, they can have a significant impact on market-clearing prices. This has been shown in the empirical analysis. Contract A reliability payments attached to MWh generation is an example of coupled incentive. Another example of this is in Contract B, where the 10% profit retention rate gives little incentive for these units to bid into the market. RMR contracts should not change a generators marginal incentive to bid into the market. Decoupling bidding incentives from RMR payments will accomplish this goal.

3. *Principle of fair compensation of RMR service*

   Given RMR service is critical to system operation, it should be compensated fairly. Whenever possible, the ISO should use positive incentives to replace negative incentives to improve market performance and generators' potential for profit. A negotiated contract should incorporate provisions that allow the generator to maximize profits under competitive conditions rather than relying on command and control measures.

4. *Improved transparency.*

   Increased transparency of what RMR generation costs will attract potential generation entrants and encourage transmission upgrades that help attain the goal of reducing and eventually eliminating the requirement for RMR contracts.

4. RECOMMENDATIONS

The MSU believes that the following economic principles would significantly correct the RMR contract incentive problems, and considers these fundamental principles to be essential for the proper functioning of RMR contracts and a competitive, efficient market:

1. ***Treating RMR generation as "must-take".*** This recommendation reflects the fact that the RMR generation requirement must be satisfied and accepted by the system for reliability purposes. The selection of RMR generation by the ISO is not a function of price, but rather a function of the system reliability requirements. Thus, the portion of RMR generation needed for grid reliability is in fact "must take" in the same sense that nuclear power is considered must-take, and should be bid accordingly. Load that must be met by RMR generation must be "netted out" prior to the Day Ahead market in order to allow all remaining supply and demand to be balanced in the most economically efficient manner through the subsequent energy markets of the PX and ISO. Although this report focuses primarily on the impacts of current RMR contracts in terms of witholding or strategic bidding of capacity in the PX market, one of the key recommendations of the report is that market distortions created by RMR contracts can only be minimized be by "netting out" all generation required from RMR units at the time of the Day Ahead market. In practice, RMR generation can be "netted out" of demand at the time of the Day Ahead market by either requiring that RMR generation be bid into the PX at zero, or be balanced against load in the Day Ahead schedule through a bilateral contract.

2. ***Declaring RMR dispatch before the day-ahead market***. Pre-dispatch is necessary for RMR to be treated as "must-take" on the day ahead market. Also, this modification would effectively remove the generator's incentive to withhold from the market to receive a potentially higher RMR price under Contract A, since the RMR generation would be known before bids to the day-ahead market were developed.

3. ***Separating the bidding incentive from the payment mechanism***. This can be accomplished by basing compensation paid to RMR owners primarily on an up front payment for the option to call them under for reliability RMR. This third proposed modification ensures that the pricing for the regulated RMR generation is separate and independent from the pricing for the unregulated energy market. The intent of this principle is to facilitate obtaining the necessary reliability services without adversely impacting the competitiveness and efficiency of the remaining energy market.

In summary, the California ISO Market Surveillance Unit agrees with the Market Surveillance Committee that the current RMR contract mechanisms provide incentives to generation owners to either withhold capacity from the day ahead markets, or bid this capacity at significantly higher prices than would occur in the absence of RMR contract incentives. This incentive results in higher energy costs to the California consumer. The MSU endorses the recommended corrective actions outlined above and firmly believes that these fundamental principles will result in a much more competitive and efficient energy marketplace.

Appendix A

Opinion of Prof. Robert Wilson

Date: 3 December 1998
To: Market Surveillance Unit, California ISO
From: Robert Wilson, Consultant

RE: Summary Report on RMR Procedures

1. RMR operations are purchased by the ISO to enhance grid reliability. The byproduct is an energy supply (not matched with any demand load) that the ISO purchases under the existing provisions of long-term contracts with generators. If this energy surplus spills over into the real-time market then the ISO must, in effect, resell this energy in the real-time balancing market.

   The basic organizing principle of the ISO's charter is that it manages the grid independently of the energy markets. This principle is implemented by accepting only balanced schedules from participating Scheduling Coordinators. In particular, the aggregate of the day-ahead schedules should be balanced.

   This principle implies that the energy acquired from RMR purchases, to the extent known and called before the PX day-ahead market opens at 7 AM, should be offered as must-take supplies in the PX. (The PX is the relevant energy market since it is the only one that is fully transparent.) If this is not done then the aggregate of the Scheduling Coordinators' balanced schedules and the unsold RMR energy is unbalanced – and in effect, the ISO is thereby participating in the energy markets, contrary to the basic market design that separates the ISO's grid management from the energy markets.

   The RMR energy is must-take because there is no prospect of reducing its supply due to price considerations; i.e., like all other must-take supplies its opportunity cost is zero even though the variable cost of generation is positive.

2. RMR operations provide the public good of grid reliability for which the ISO is responsible. RMR operations and the energy byproduct are purchased outside the market, via contracts, because otherwise the local monopoly power of the generators would often enable them to demand prices above the market price that the ISO would be forced to accept to ensure grid reliability.

   The important principle to guide the contract specifications is that the ISO must obtain the requisite RMR reliability services without impairing the competitiveness of the general market for energy. That is, the ISO's RMR purchases of operations and energy must decouple reliability management from the equalization of demand and supply in the much-larger competitive part of the energy market.

The Market Surveillance Unit's proposed contracts show that this can be accomplished if the RMR energy passes through the PX market as must-take. The must-take provision is required because otherwise the absence of any part of the RMR energy in the day-ahead market and its spillover into later markets would tend to raise day-ahead prices and lower real-time prices, which can be corrected only by elaborate arbitrage – such as UDC's withholding demands from the day-ahead market to real-time market – which would undermine the key design of the California markets in which most transactions are to be accomplished via balanced day-ahead schedules, and the real-time market is reserved for intra-zonal balancing (at the ISO's expense!).

3. Regardless of the strength of the present evidence pro or con that RMR contractors might be withholding RMR energy from the day-ahead markets to influence the market price obtained by other units in their portfolios, or to obtain the greater of the RMR price and the market price, the fact remains that the incentive to withhold poses a long-term risk of severe proportions that cannot be ignored. Eliminating this incentive by requiring called RMR energy to pass through the PX market as must-take is necessary to ensure decoupling of grid reliability operations from the competitive energy markets, and thereby to ensure the continued competitiveness of the energy markets. The Market Surveillance Unit's proposal to allow the RMR contractors to obtain the maximum of the market price and the RMR payment provides assurance that no RMR contractor is disadvantaged.

   Claims are reportedly made that treating RMR energy as must-take could lower the day-ahead price and thereby reduce the profitability of other units in an RMR contractor's portfolio. If this were true it would reflect incomplete arbitrage between the day-ahead and real-time prices, in which case the contractor could preserve its profitability by withholding some energy from the day-ahead market in order to obtain higher expected prices in the subsequent real-time market. The evidence is strong, however, that there is no systematic difference between the day-ahead and real-time prices, and there is no indication that any future scenario would entail a systematic divergence in prices. Therefore, I see no convincing evidence that contractors' profits on their other units will be reduced by the MSU's proposals.

Appendix B:

Summary of Recommendations Concerning Revising RMR Contracts

by Market Surveillance Committee, California ISO

As the Market Surveillance Committee (MSC) has stated in its earlier discussions on this subject, it is best to explicitly recognize that RMR contracts are by definition 'out of market' arrangements between the ISO (and transmission owners) and certain generators. These units have local market power in the sense that under certain grid contingencies they are required to run for local grid reliability reasons. They are the only (or one of a very small number of) available suppliers of these local grid reliability services. The RMR contract is therefore an agreement to provide these services at regulated prices because of the extreme local monopoly or oligopoly power possessed by RMR units. These local reliability services are similar to electricity supplied by the vertically integrated electric utility in the old geographic monopoly regime and therefore should be supplied at regulated prices.

Therefore, without local grid reliability services provided at regulated prices, it makes little sense to attempt to run a competitive market for electricity in California for the current configuration of the California grid and set of available generation capacity. During those periods when certain generation facilities are needed for local grid reliability needs, the relevant plants can bid virtually any price and still be dispatched. One can therefore think of these local grid reliability services as facilitators of a competitive market for electricity supply. Given this perspective, it is best to make payments for the provision of these local grid reliability services in a manner that minimizes their impact on the workings of the energy and ancillary services markets. This implies making fixed payments to generators in exchange for operating conditions, so that their bidding incentives into the PX and ISO markets are unaffected by their RMR status. Any compensation scheme for RMR energy that creates an opportunity cost to bidding into the PX or any ancillary services market may be used by an RMR unit owner to elevate prices in the PX and ancillary services market. An important goal in designing an RMR compensation scheme is to prevent such an extension of local market power.

The type of contract that meets these goals is a pure option contract, with periodic (monthly or annual) fixed payments with no requirements for a rebate of deemed profits. The size of the fixed payment made to RMR generators is, to a large extent, a subject of negotiation and regulation. There are however, several economic principles that can inform these negotiations over the size of the fixed payment received by RMR generators. These principles include:

1. **Fixed costs** associated with the going-forward operation of the generation unit should play a role in the calculation of a fixed RMR payment. Because some units are expected to be 'must-run' for reliability purposes far more often than others, the percentage of annual fixed costs included in these payments may need to be scaled in some way that reflects the relative contribution of each plant to system reliability during the year. The purpose of RMR contracts is to compensate certain generation units in such a way that ensures their continued operation, which has been deemed essential for reliability purposes. Pre-existing capital costs, being sunk, have little to do with an economic decision to continue operation of a plant.

2. Stakeholders may or may not decide that **opportunity costs**, such as forgone market revenues from energy or ancillary services markets should be incorporated into fixed RMR payments. The special

status of these units also entails special responsibilities. In our opinion, the fixed subsidies received for continued operation represent a *quid pro quo* for some degree of forgone market revenues. If it is decided that RMR units must be compensated for opportunity costs, however, we strongly recommend that this compensation be in the form of fixed payments, rather than an energy payment linked to specific, hourly market outcomes. The fact remains that, at certain times, a large fraction of a plant's capacity is required for local reliability purposes, so that at these times such units simply cannot provide ancillary services. If they cannot provide these services, they should not be allowed, or given the incentive to, influence the market prices of these services.

3. Unit **start-up costs** represent a difficult incentive problem. On the one hand, generation units profit from having these start-up costs, including ramp-up and ramp-down costs, covered by RMR payments, regardless of the rate paid for RMR energy, and may therefore adjust their market bids accordingly. On the other hand, generation units fear that the ISO, if it were not responsible for start-up costs, may call on these units more than just for grid reliability reasons. The best way to resolve the incentive problems on both sides is to incorporate expected start-up expenses into the fixed annual payments made to units. Unit owners would receive an fixed annual payment based on the expected number of startups for local reliability needs that is independent of the number of times the unit is actually started-up or called to provide energy or ancillary services under its RMR contract. Under this scheme, unit owners are liable for the full cost of all start-ups they incur whether it is to provide RMR energy, or energy or ancillary services through any of the PX or ISO markets. Generator decisions on market bidding and participation would therefore not be influenced by the payment for start-up costs associated with an RMR energy or ancillary services calls versus the lack of any explicit payment for start-up costs for supplying energy or ancillary services into a PX or ISO market. The current RMR contract regime pays for the start-up costs associated with an RMR call if the unit is currently shut down. A generator can use knowledge of the timing of its unit's RMR energy calls to determine the timing the unit's shutdowns so that a large fraction of the unit's start-up costs are covered by its RMR contract. The amount added to the fixed payments that is linked to RMR specific start-up costs could be periodically re-adjusted to both correct inaccuracies in the forecasted start-ups for that unit and to provide an incentive to the ISO to mitigate the number of starts needed for RMRs.

The protocols for the operation of RMR units have also been a subject of the current negotiations. The issues in question include the conditions under which units can be called under RMR contracts and the payments that they receive for each unit of energy provided under RMR. On these questions, we advise the following:

1. Must-run energy needs, which are based upon load forecast and physical system conditions, should be made public before the day-ahead energy and ancillary services markets are held.
2. The per-unit of energy or ancillary services variable rate of compensation for providing RMR energy or ancillary services should be the marginal cost associated with providing that energy or ancillary service.
3. The owners of the generation that has been declared to be must-run must at this point decide whether they wish to receive, as their per MWH compensation rate, their respective RMR variable rates or the as yet undetermined PX price for that hour for their RMR energy.
4. The total RMR supply for that hour should then be treated in the same way as regulatory must-take capacity in the PX bid curve, because it is a regulated service that has already been paid for with the up-front payment. Consequently, it should therefore be a price-taker in the PX market.

The impacts of RMRs payment schemes on bidding incentives can, and have, had a significant impact on market-clearing prices. Given the significance of these impacts, it is important to de-couple, as much as is possible, reliability must-run requirements from the performance of the broader markets. It is therefore much less risky to the competitiveness of the ISO and PX markets to err on the size of fixed payment commitments than to attempt find a compensation scheme for must-run generation that is linked to hourly market performance. Linking payments for RMR services to hourly market outcomes runs a real risk of producing higher market prices for all energy and ancillary services purchased from PX and ISO markets. Such a linkage between RMR payments and market outcomes therefore unnecessarily increases market prices and total electricity supply costs for final consumers.

An additional advantage of up-front payments for all non-variable cost RMR services is the transparency of the non-variable cost payments received by RMR unit owners to current and potential generation entrants and current regional transmission operators. The ultimate aim of the ISO is to eliminate as many of these RMR units from the California market as rapidly as possible without reducing system reliability. This will be most rapidly and efficiently accomplished if the costs of these units are transparent to all market participants. If the above-marginal cost payments made to RMR generation for the services they provide are made in the form of a single up-front payment known to current and potential market participants, instead of as a complicated per unit payment scheme which depends on the number of times a generator is called under the contract and its market revenues, the economic signals for new generation plant location or where grid expansion or enhancement should occur will be much stronger. Under this up-front payment scheme new entry and/or grid expansion should take place where these up-front payments are the highest. Under this scheme, California should more rapidly progress to the efficient competitive market all participants desire.

Appendix C: Description of Withholding Analysis Methodology

This appendix summarizes the methodology used to assess withholding of capacity from the day ahead PX and ancillary service markets.

Economic Daily Energy Schedule

The step of the analysis involved an assessment of the specific days and hours in which in would be economic for units under RMR contracts to operate and sell energy through the day ahead energy market. Throughout this report, results of this initial portion of the analysis is referred to as the Economic Energy Schedule or *Economic MWh* for each unit during each hour. Since Economic MWh represents the total MWh that a unit could have scheduled in day ahead energy markets in order to maximize net revenues, this number forms the basic denominator ultimately used in calculating a “withholding rates” or percent of energy we estimate could have cleared the PX market, but that did not either clear the PX or ancillary service markets.

For this analysis, the decision of whether or not it would be economic for each unit to participate day ahead energy markets is first assessed on a daily basis, based on the net marginal revenues that would be earned by given actual market clearing prices, and each unit’s variable operating and start-up costs.

- First, an hourly energy schedule that maximizes net revenues for each unit is developed, by assuming that units would run at maximum capacity when the PX market clearing price (MCP) exceeds the unit’s MC (marginal operating cost, including fuel, variable O&M, and emission costs). During hours when the PX MCP is less than a unit’s MC, it is assumed that units either shut down or operate at their minimum operating level.

- Units with start-times of less than 2 hours are assumed not to have a market energy schedule during hours when the PX MCP < MC, reflecting the fact that it would typically be economic for these units to shut down (or provide ancillary services) rather than to sell energy at market prices lower than their marginal operating costs. For these units, potential *net daily revenues* are therefore calculated by first summing up hourly net marginal revenues from hours when PX MCP > MC, and then subtracting the complete cost of starting up the unit.

- Units with start-times of 2 hours or more are assumed to have a market energy schedule equal to their minimum operating level during hours when the PX MCP < MC, reflecting the fact that for days in which these units are operating, it would be most economic for these units to minimize marginal operating losses during these hours by operating at this minimum level (and perhaps provide ancillary services). For these units, potential *net daily revenues* are also calculated by first summing up hourly net marginal revenues (including losses) for each 24 hour period.

Results of this daily analysis are then used to determine periods of consecutive days (lasting from one day to many days) over which it would be economic for each unit to start-up and continue operating. With this approach:

- Total net daily revenues are first summed up for each series of consecutive days (spanning up to the next seven days) when net daily revenues would be positive (indicating it would be profitable for the unit to operate based on variable operating costs on revenues).

- If the sum of net daily revenues for a group of consecutive days (up to seven days) exceeds unit start-up costs, it would be most economic for the unit to start-up up on the first day of this period, and continue operating each consecutive day for which daily revenues would continue to exceed daily variable operating costs.

This "forward looking" approach was specifically designed to simulate how the decision to start-up units was described by generation owners in discussions with ISO staff. It should be noted that this approach assumes that units start-up only at the beginning of periods (lasting one or more days in duration) when operating revenues would be sufficient to cover start-up costs. We believe these are conservative assumptions for several reasons.

- Although the algorithm does assume perfect foresight of day ahead energy prices, the algorithm also assumes every start-up has to be a profitable decision based solely on these energy revenues. In real markets, there is no such guarantee that all start-ups will be profitable, and generators may often start-up based on merely the expectation that start-up costs will be covered by subsequent revenues as actual market conditions unfold.

- In addition, potential revenues for ancillary services which can be provided when units are online but not operating at full capacity are not factored into the decision to start up or continue operating a unit. Revenues from ancillary services provide a major source of additional revenues for RMR units, particularly those with higher variable operating costs.

A more detailed description of the equations and inputs used to calculate the Economic MWh of each unit is provided below.

Description of Algorithms Used to Calculate Capacity Withholding

1. Calculate economic daily energy schedule

For units with start-times ≥ 2 hours:

For hours when PX > MC (at Minimum Capacity, including O&M and emissions)

Economic MWH = Maximum Unit Operating Level (MW)

For hours when PX ≤ MC (at Minimum capacity)

Economic MWH = Minimum Unit Operating Level (MW)

For units with start-times < 2 hours (no units have start time between 2 and 6 hours):

For hours when PX > MC (at Maximum capacity):

Economic MWH = Maximum Unit Operating Level (MW0

For hours when PX ≤ MC (at Maximum capacity):

Economic MWH = 0

2. Calculate net hourly revenues (assuming unit will be active)

For units with start-times ≥ 2 hours:

For hours when PX > MC (at Minimum capacity)

$$\text{Net Hourly Revenue} = (\text{PX\_MCP} - \text{MC\_Max}) \times \text{Max\_MW}$$

For hours when PX ≤ MC (at Minimum capacity)

$$\text{Net Hourly Revenue} = (\text{PX\_MCP} - \text{MC\_Min}) \times \text{Min\_MW}$$

For units with start-times < 2 hours :

For hours when PX > MC

$$\text{Net Hourly Revenue} = (\text{PX\_MCP} - \text{MC\_Max}) \times \text{Max\_MW}$$

For hours when PX ≤ MC

$$\text{Net Hourly Revenue} = 0$$

3. Calculate net daily revenue

For units with start-times ≥ 2 hours:

Net Daily Marginal Operating Revenue = ∑ Net Hourly Revenue

For units with start-times ≤ 2 hours:

Net Daily Revenue = ∑ Net Hourly Revenue for hours 1 through 24
- Start-up Fuel Cost (@ ~ $2.75/MMBTU)
- (Start-up MWh × $60/MWh)
- (Shutdown MWh × $60/MWh)

Fuel costs were based on average monthly gas prices in southen and northern California provided by SCE and PG&E, respectively.

4. Calculate unit start-up and operating days

For units with start-times ≤ 2 hours, it would be economic for units to start-up and operate only in days when Net Daily Revenue (including start-up costs) > 0.

For units with start-times ≥ 2 hours, it would be economic to start-up if the *sum* of net daily revenues (not including start-up) for all consecutive days when Net Daily Revenues > 0 exceed start-up costs.

Withholding of Capacity From Day Ahead Energy Market

Withholding of capacity from the day ahead PX markets was estimated based on the *difference* between the economic MWh for each unit during each hour, and each units' actual day ahead energy schedule, plus any ancillary service capacity provided through the day ahead AS market).

For each unit during each operating hour, potential MWh withheld from day ahead energy market was calculated using the following equations:

Withheld MWh = Economic MWh – Final Energy Schedule (MWh)
– AS Capacity (MW) – Real Time Energy (MWh)

For the relatively small portion of hours when Economic MWh > Final Energy Schedule (MWH) + AS Capacity (MW) + Real time Energy (MWh), Withheld MWh was set to zero, rather than a negative number.

The definition of capacity withholding described above accounts for the actual level of capacity clearing day ahead energy and A/S markets. As a result, the MSU believes this definition of withholding provides the best indication of the degree of withholding of capacity from day ahead markets that may be attributed to incentives created (or exacerbated) by RMR contracts.

A second case, based on a second definition of withholding, was also calculated (Case 2 in the report). Under this definition of withholding, for all hours in which any unit had an energy schedule that was lower than it's Economic MWh, but still high enough to meet any Minimum Reliability Requirement established for that hour, it was assumed that no capacity was withheld due to the expectation that the units may be called under their RMR contracts. As noted in the report, this second case is designed to represent a more conservative of withholding directly attributable to incentives created by RMR contracts, rather than withholding that may result from the broader incentives generators may have to influence market prices through strategic bidding or capacity withholding.

Direct Costs of Withholding Capacity From Day Ahead Energy Markets

For hours in which analysis indicates it would be economic for units to have a day ahead energy schedule, the *increase* in energy scheduled to meet the ISO system/'s Minimum Reliability Requirements due to withholding from day ahead markets for each unit in each hour is calculated as follows:

If Economic MWh > Minimum Reliability Requirement:

Economic_RMR_ Called = RMR Schedule Change

Otherwise:

Economic_RMR_ Called = 0

The direct cost of this increase in energy called under RMR contracts for each unit in each hour was calculated with the following equation, in which the actual hourly PX price is used as a proxy for the value of energy purchased by the ISO under RMR contracts:

Added_Cost_Per_MWh = Reliability Payment ($/MWh) + Variable Operating Cost ($/MWh) + Startup Costs (Pro rated on a $/MWh basis) - Real Time Energy Price in Subsequent Market ($/MWh)

The Decremental Energy Price in Subsequent Markets is the potential revenue of the RMR energy for the ISO (assumed to be 0 in this analysis).

The total direct cost for each unit in each hour is therefore equal to:

Total Direct Cost = Economic_RMRCalled × Added_Cost_Per_MWh.

Indirect Direct Costs Withholding

The indirect costs of capacity withheld from the day head energy markets due to RMR Contracts was estimated using two approaches.

Preliminary Analysis

Under this first approach, used in the preliminary analysis, the effect of a change in supply on the final PX MCP was calculated using an econometric model of the PX MCP as a function of total demand. In order to capture the different effects of withholding (or changes in demand), analysis was performed on a month-by-month level, with separate calculations made for each level of demand in the PX market (e.g. 30-31 GWh, 31-32 GWh, 32-33 GWh, etc.) This approach was utilized during the first stage of this study in order to develop an initial estimate of the potential indirect impacts of capacity withheld from the PX .

The effect of a change in supply on the final PX MCP was calculated using an econometric model of the PX MCP as a function of total demand As shown in the figure below, the PX MCP rises in a highly linear patterns at demand levels of up to about 30 GWH. Above this level of demand, market clearing prices rise exponentially. Consequently, piecewise linear /non-linear model was used to reflect the actual patterns of market clearing price at different levels of demand.

A separate supply/demand model was for developed each month to reflect the changing nature of market clearing supply and demand quantities in different months. In order to capture the effects of withholding on supply at different levels of demand, analysis was performed on a month-by-month level, with separate calculations made for each level of total overall demand in the PX market (e.g. 30-31 GWh, 31-32 GWh, 32-33 GWh, etc.)

First, the PX market clearing price under actual historical conditions (PX_MCP1) at each level of demand (PX_MCQ) during each month was calculated using the supply equations depicted in Figures B-1 through B-4.

PX_MCP1 = f (PX_MCQ)

For each month, the supply/demand equations at each level of demand was adjusted to simulate the “shift” in the supply function that would result if additional supply capacity had been bid at prices lower than the actual PX_MCP.   As depicted below, the supply/demand function was adjusted based on the amount of capacity withheld on average during each hour in the month when total PX loads were at each level:

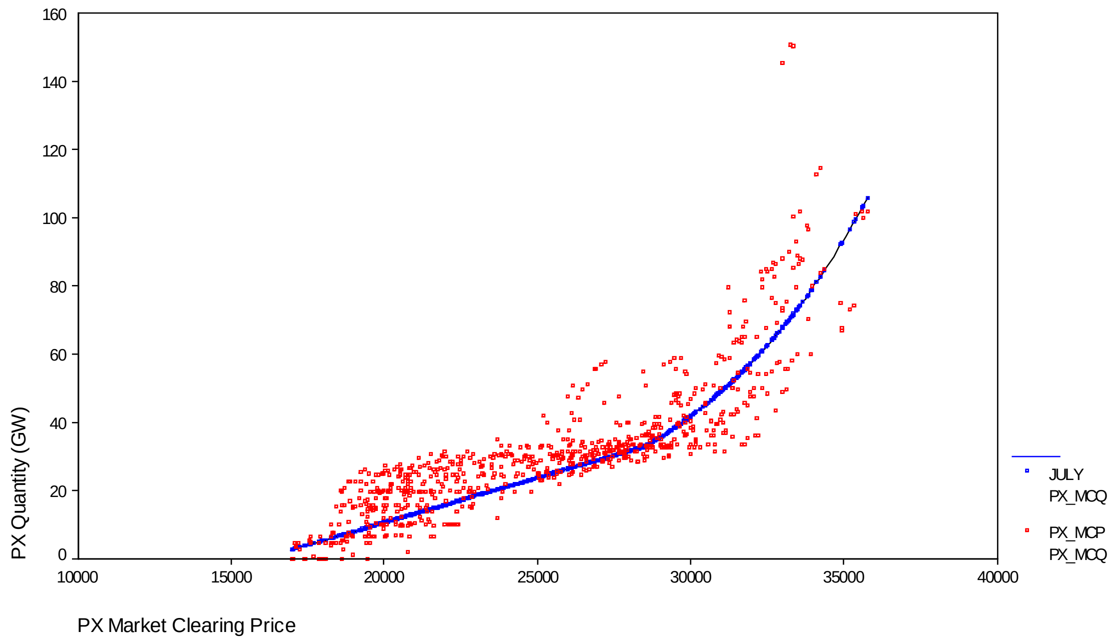
PX_MCP2 = f (PX_MCQ – Withheld MWH)

The resulting change in price was then used to calculate the increase in total PX costs due to capacity withheld:

Indirect Cost = PX_MCQ × (PX_MCP1 – PX_MCP2)

This approach was utilized during the first stage of this study in order to develop an initial estimate of the potential indirect impacts of capacity withheld from the PX. A comparison of results from this method with results derived from actual supply and demand bid data (summarized in the following section) indicates that the method used in this preliminary analysis yielded estimates about 10% higher than results based on actual PX demand and supply bid data.

JULY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25000
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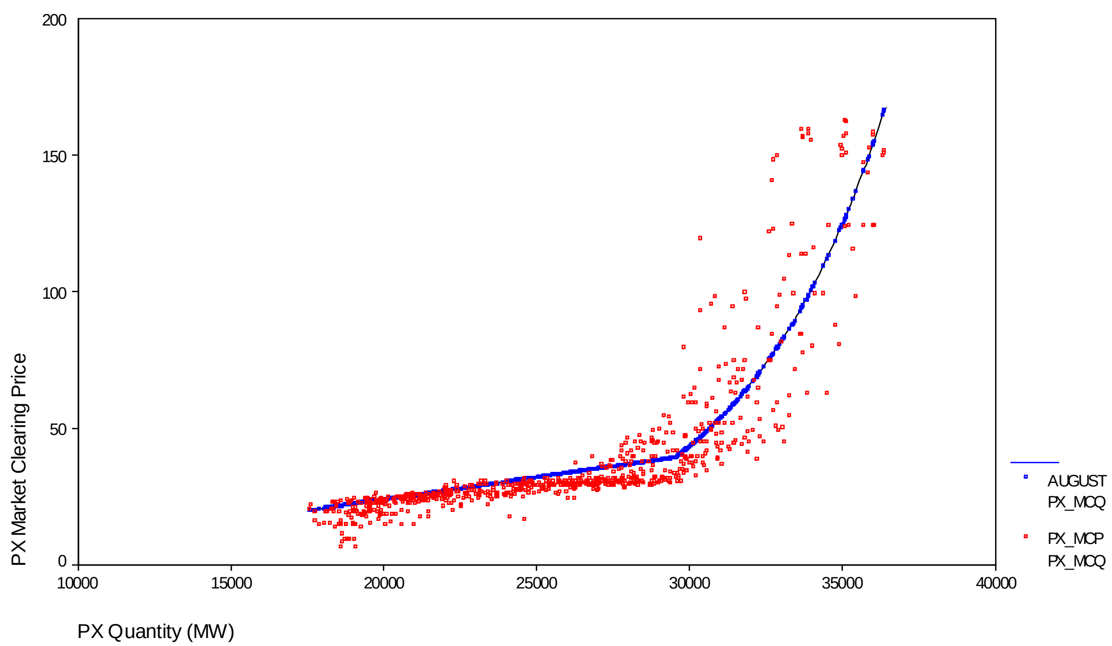
PX Quantity (GW)
PX Market Clearing Price
JULY
PX_MCQ
PX_MCP
PX_MCQ

AUGUST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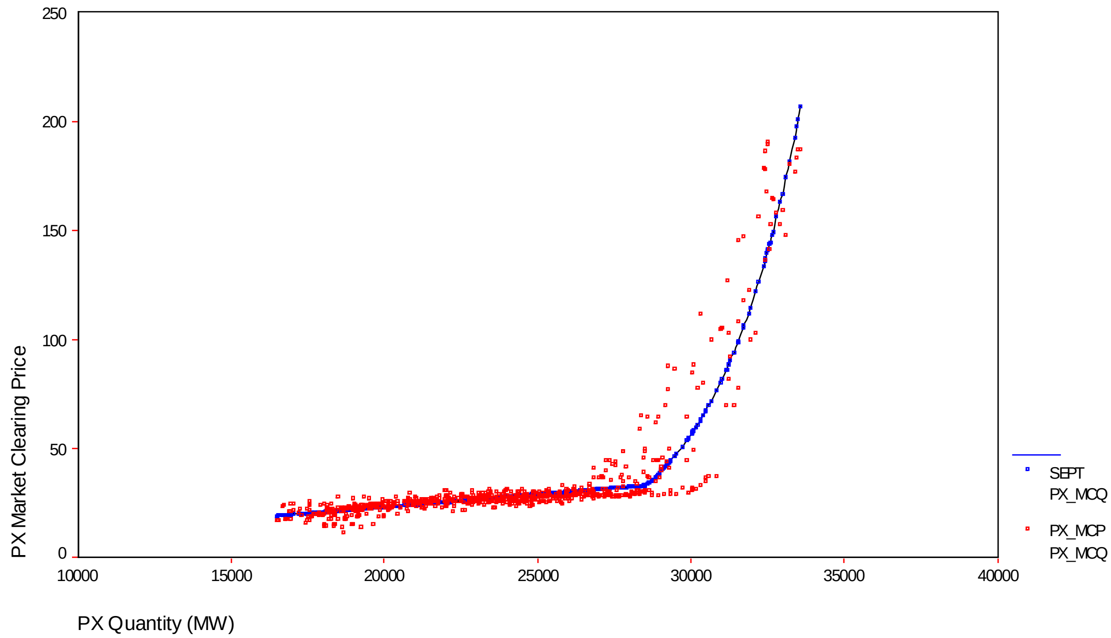
PX Market Clearing Price
PX Quantity (MW)
AUGUST
PX_MCQ
PX_MCP
PX_MCQ

SEPT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PX Market Clearing Price
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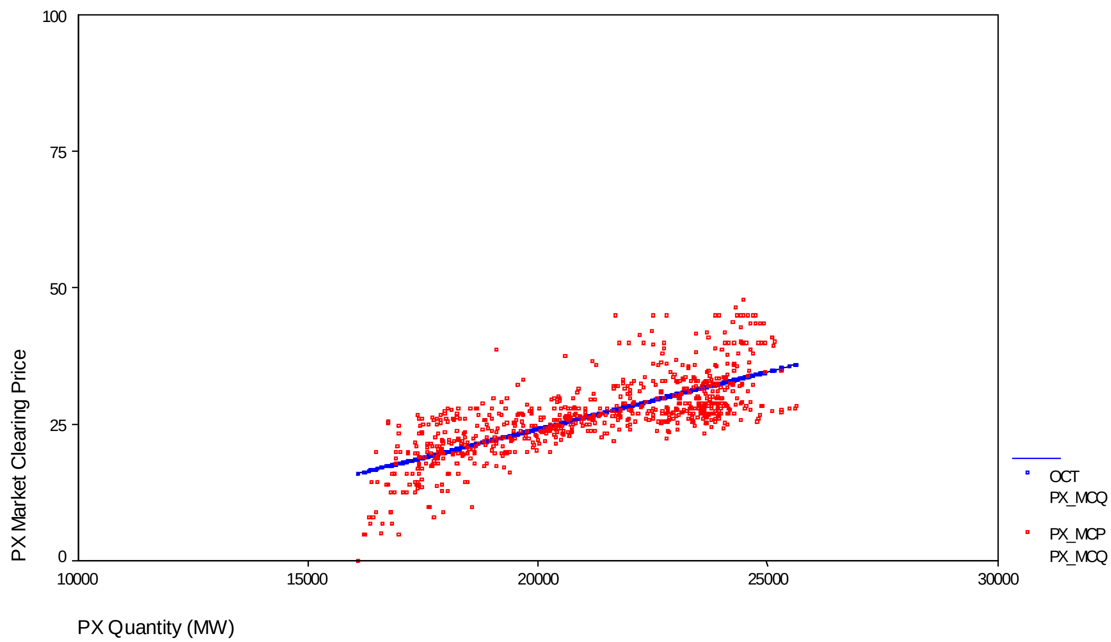
SEPT
PX_MCQ
PX_MCP
PX_MCQ

OCT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PX Market Clearing Price
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20000
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PX Quantity (MW)
OCT
PX_MCQ
PX_MCP
PX_MCQ

Final Analysis of Indirect Costs

For the final analysis summarized in this report, we use a similar approach, but estimate the indirect impacts of withholding on day ahead energy prices using actual supply and demand bid segments for each hour provided by the PX.

With this approach, results of our analysis of capacity withheld from the day ahead markets that could have economically cleared the PX market were first used to generate additional "bid segments", representing additional supply that would have been available to different price levels. During hours when each unit's MC < PX, bid segments representing capacity withheld from the day ahead market were priced at the unit's MC (including fuel, emissions and variable O&M). During hours when each unit's MC > PX, (when units with start times of over 6 hours were assumed to operate at minimum operating levels), bid segments representing capacity withheld from the day ahead market were priced zero, representing the opportunity cost of capacity from units needing to continue to operate at minimum capacity during these hours.

The market clearing price in the PX was then recalculated with these additional supply bid segments added to actual bid segments submitted to the PX. The increase in PX price due to withholding of this additional capacity was then calculated based on the difference in the PX price with and without these additional bid segments. Indirect costs were calculated by multiplying the change in PX price by the actual market clearing quantity (PX_MCQ) in each hour, as shown in the equation below.

$$\text{Indirect Cost} = \text{PX\_MCQ} \times (\text{PX\_MCP1} - \text{PX\_MCP2})$$

As noted above, this approach yielded estimates of indirect costs about 10% lower than the method used in our preliminary analysis.