UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	)	Docket Nos. ER98-496-000
	)	and ER98-2160-000
	)	
	)	

INITIAL TESTIMONY OF ERIC HILDEBRANDT
ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. Please state your name and address.

A. My name is Eric Hildebrandt. My address is 151 Blue Ravine Road, Folsom, California 95630.

Q. Where are you employed and in what capacity?

A. I am employed by the California Independent System Operator Corporation ("the ISO") as Manager of Market Monitoring Systems in the Department of Market Analysis.

Q. Please give your educational and professional background.

. I hold a B.S. degree in Economics from the Colorado College, and an M.S. and a Ph.D. in Energy Management and Policy from the University of Pennsylvania. I have specialized in economic analysis and market research relating to energy issues for over ten years, with emphasis on performing economic and market research, planning and evaluation studies for the electric utility industry. I began my career in energy research at the Center for Energy and Environment at the University of Pennsylvania, and then worked for over six years as an economic consultant to the electric utility industry with the firms of Xenergy Inc. and Hagler Bailly Consulting in Philadelphia, Pennsylvania. Prior to joining the ISO, I worked for over three years at the Sacramento Municipal Utility District as Supervisor of Monitoring and Evaluation. I have published numerous articles on energy issues in professional journals and have frequently presented my research in academic and industry forums.

Q. Are you familiar with the issues in the current proceedings?

A. Yes. The issues are the appropriate Fixed Option Payment Factors to be used in calculating the Monthly Availability Payments to be paid to the Owners of Reliability Must-Run (“RMR”) (generating) Units, and the portion of the costs of Capital Items and Repairs necessary at such generating units that should be paid by the ISO, under the Must-Run Service Agreements (“RMR Agreements”) between the ISO and the Owners of the RMR Units.

Q. Are you familiar with the background of these issues?

A. Yes. As a member of the Department of Market Analysis of the ISO, part of my duties has been to monitor the operation of the California Energy and Ancillary Services markets, including the effect on those markets of the RMR Agreements and the bidding behavior of the RMR Units, and to make recommendations to ISO management for changes in the RMR Agreements, the ISO Tariff, or bidding protocols or other protocols, to increase the efficiency of those markets. In order to carry out this part of my duties, I have familiarized myself with both the earlier versions and the current versions of the RMR Agreements, the behavior of RMR Units in the markets, and the issues in this proceeding, both as those issues existed during the evolution of these proceedings over the last many months, and the issues as they remain for resolution through the current hearings. I assisted in the preparation of the *Report on Impacts of RMR Contracts on Market Performance*, which was issued by the Department of Market Analysis (then known as the Market Surveillance Unit) in March 1999, and filed with the Federal Energy Regulatory Commission ("FERC") in April 1999. I also assisted in the preparation of the ISO's *Annual Report on Market Issues and Performance*, dated June 1999, which was prepared by the Department of Market Analysis (again, when known as the Market Surveillance Unit) and filed with FERC in June 1999. The *Annual Report* contains a discussion of the RMR issue and the RMR Agreements. I also submitted a statement to FERC in support of the Offer of Settlement filed in these proceedings on April 2, 1999.

Q. What is the purpose and organization of your testimony?

A. My testimony has four purposes. In Part I, I will briefly explain the nature of the problem created by the existence within a competitive generation market of certain units that must run at certain times to ensure the reliability of the transmission grid, the various ways in which one might try to deal with the problem and the way in which California chose to address the problem when it moved to competitive generation markets. In Part II, I will explain the market-distorting effects of the original form of RMR Agreement, and how the current form of the Agreement moderates those effects. In Part III, I will explain the objectives of the ISO as they relate to the issues that remain for resolution in this proceeding, and explain the ISO's recommended approach to determining the appropriate Fixed Option Payment Factor for an RMR Unit. In Part IV, I will briefly describe the ISO's recommended approach to determining the portion of the cost of Capital Items or Repairs to be paid by the ISO on behalf of the Responsible Utility.

Q. Please summarize the major points to be made in your testimony.

A. The existence within a competitive generation market of certain units that must run at certain times for reliability reasons presents regulators with the problem of preventing those units' exploitation of their market power while, at the same time, ensuring their availability when needed and avoiding distortions of the overall competitive market. In California, the mechanism for addressing all of these goals is the RMR Agreement. Certain aspects of the original form of that

Agreement failed to meet the regulatory goal of avoiding distortions to the overall competitive market; the changes to the RMR Agreement included in the Offer of Settlement of April 2, 1999 have partially mitigated that problem. One consequence of the changes, however, was to create the need to determine an appropriate Fixed Option Payment Factor for RMR Units operating under Condition 1. The ISO has three objectives related to system reliability and overall market efficiency that are affected by the determination of the Fixed Option Payment Factor. Those are (1) ensuring that an RMR Unit remains available and is in operation when needed to ensure local reliability, (2) ensuring that the amount paid to ensure that availability is reasonable and not excessive, and (3) ensuring that the costs associated with ensuring local reliability through RMR Units can be compared to the costs of potential longer-term alternatives for meeting local reliability requirements, to allow the costs of meeting the reliability needs to be reduced to the extent possible over the longer term through a competitive process. Fixing the amount of the Monthly Availability Payment at the amount of net incremental costs imposed on a unit by virtue of its being designated an RMR Unit is consistent with all these objectives. This “incremental cost” approach is also appropriate for determining the ISO’s share of any Capital Item or Repair: the ISO’s share should be only the net cost of any portion that was occasioned solely by virtue of the unit’s having been designated an RMR Unit.

<u>PART I</u>

Q. What is the purpose of this part of your testimony?

A. In this section, I will explain the nature of RMR Units, the challenges they present to regulators in the context of a competitive Energy market, and how California chose to address those challenges.

Q. What is an RMR Unit?

A. An RMR Unit is one that must provide Energy and/or Ancillary Services to the transmission grid at certain times in order to ensure that reliability of the grid is not impaired. The need for an RMR Unit is a consequence of limited transmission system capacity at certain locations, which makes it necessary under specific loading conditions to ensure that some portion of the load at those locations is met by generation within the area rather than by Energy imported into the area over the transmission system. In California, the ISO also calls upon RMR Units in real time to help resolve Intra-Zonal Congestion when the Adjustment Bid market is not workably competitive. The RMR Agreement also allows the ISO to call upon an RMR Unit to provide Ancillary Services in the event that the supply of Ancillary Services bid into the ISO markets from competing sources is insufficient to meet the ISO's need for those services or, sometimes, when the supply that is bid does not yield a workably competitive market.

Q. What is the nature of the problem that is created by the existence of RMR Units in the context of a competitive generating market?

A. At those times when such a unit must be generating in order to ensure the reliability of the transmission grid, it effectively has a form of local monopoly power. Many other units are able to displace an RMR Unit’s output when there is no transmission constraint, and the only need is for sufficient Energy to balance the overall load on the system. However, at those specific times when there is a binding transmission constraint, and only a particular unit can, because of its strategic location, meet a local load, it has in effect a monopoly of the market for meeting that local load, with no effective competition from either other generating units in the area or the transmission of Energy from units located outside the area. At those times, the absence of any viable substitute for the unit’s generation from the perspective of system reliability gives this unit the classic market power of a monopolist – the power to raise prices, at least in the short run, unimpeded by competition. And, in this case, due to the long lead times for either a transmission upgrade or the construction of a competing generating unit in the area, the “short run” during which the unit could control prices could be rather long.

Q. How should the problem of a unit with local market power in the context of competitive generation markets be approached by regulators?

A. Regulators should seek to intervene in competitive markets to the minimum extent possible. The existence of units with local market power, however, requires regulatory intervention. The regulator should seek to address three separate goals. First, the regulator must mitigate to the extent possible a unit's ability to exercise its local market power to earn monopoly rents, *i.e.*, supra-competitive profits (profits in excess of profits that would result under competitive market conditions). Second, the regulator must ensure that the unit receives adequate compensation to assure its availability at times when it is needed for grid reliability but it would otherwise be uneconomic for the unit to run on the basis of market prices. Finally, the regulator should ensure that the mitigation measures do not affect the functioning of the competitive markets beyond the areas affected by the transmission constraint that gives the unit its market power.

Q. How can the possession of local market power by certain units at certain times affect pricing in generation markets that are run competitively, as in California?

A. In California's market, the Market Clearing Price for generation is set through competition over a geographic area (or congestion zone) that is greater than the area affected by the local transmission constraints that create the need for "must-run" generation. In those cases, the must-run generating unit sometimes does not clear the market. Because that unit must be in operation to ensure system reliability even if it does not clear the market, the ISO must "constrain on" that unit. If a unit that must be constrained on were paid the unit's bid price, one can readily see that a unit operator that could foresee a high probability of the unit's being required for reliability would have a strong incentive to bid the unit's capacity into the Day-Ahead Market for Energy at an amount significantly higher than its marginal operating cost or its opportunity cost in terms of potential revenues from selling this Energy or capacity in subsequent Energy and/or Ancillary Service markets. This is because the unit operator would be secure in the knowledge that even if the unit did not clear the market, it still would likely be called "out of merit order" and receive its bid price. For a unit that would be economic to operate at market prices, the difference between the unit's bid price (at which it is paid) and the Market Clearing Price would represent "monopoly rent" attributable to the unit's local market power. For a unit that would not be economic to operate at Market Clearing Prices, the difference between the unit's bid price (at which it is paid) and the unit's marginal operating costs (or opportunity costs in terms of other markets) would represent "monopoly rent" attributable to the unit's local market power.

Q. How has California chosen to address the problem of the existence of must-run generating units in the context of competitive generation markets?

A. California chose to have Market Clearing Prices for generation set within relatively large geographic areas (or congestion zones), which are much larger than the local areas affected by local transmission constraints that create the need for must-run generation. When additional generation is needed for local reliability (after Final Day-Ahead Schedules for Energy are submitted to the ISO), rather than dispatching and paying operators "as bid," California chose to compensate units by means of previously agreed-upon, contractually based payments when they do not clear the market but must be in operation to ensure system reliability. This is the genesis of the RMR Agreement.

RMR Agreements are, in effect, contracts under which California consumers (through the ISO and the Responsible Utility) provide a payment to certain units in consideration for the assurance that such units can be required by the ISO to be in operation when needed to ensure local system reliability. Since RMR costs are passed through by the ISO to Responsible Utilities, an RMR Agreement is similar in nature to a bilateral contract for local reliability services between the Responsible Utility and the RMR Owner. And, of course, the fundamental purpose of each of these contracts is the same, namely, to provide a means of ensuring that sufficient generation is in operation to ensure local reliability and compensating generation owners for the cost of ensuring local reliability through must-run generation.

Q. Do the RMR Agreements in California adequately meet the three regulatory goals to which you alluded earlier?

A. In general, yes. As I explained earlier, those goals are mitigating the exercise of local market power, providing a mechanism to ensure that required generation is in operation to ensure local system reliability when it otherwise would be uneconomic for this generation to operate at market prices, and avoiding adverse effects on the remainder of the competitive market.

The RMR Agreement mitigates the exercise of local market power by paying the RMR Units only a contractually agreed upon (or FERC set) price when they do not clear the market, but are needed to be in operation to ensure local reliability. This means that these Units are unable to "set their own prices" (and extract monopoly rents) at those times. In addition to mitigating local market power, the RMR Agreement also provides a mechanism for fairly compensating RMR Units when it is necessary that they operate for local reliability, but it would be uneconomic for them to operate at Market Clearing Prices. Under all RMR Agreements that have been in effect, when RMR Units have been dispatched (or "constrained on") by the ISO to ensure local system reliability, the ISO (and ultimately the Responsible Utility) has paid for unit start-up costs, plus any difference between market prices and the variable operating costs of the RMR Units. Thus, there is no financial burden on the RMR Units from being called upon.

It should be noted that, in practice, when an RMR Unit is "constrained on" by the ISO after the Day-Ahead Market (and the Owner does not elect to provide this Energy through a market transaction, as permitted under the new RMR Agreement), the resulting generation produced by the RMR Unit is actually sold in the Real Time Market at the price for Imbalance Energy. Since these market revenues are credited to the RMR Owners through the ISO settlement process, the Responsible Utilities only pay RMR Owners for the difference between these market revenues and the variable costs associated with providing this must-run generation. In effect, this payment system "makes whole" RMR Owners for any variable operating costs associated with the need for them to operate when "constrained on" by the ISO to ensure system reliability. In addition to providing for payment covering the net variable operating costs associated with RMR generation requirements, each form of the RMR Agreement has provided for additional payments that cover or exceed the incremental costs imposed on RMR Owners due to the need to provide RMR service.

Finally, with respect to the third goal I have described -- avoiding effects on the remainder of the competitive market -- certain aspects of the original RMR Agreement affected prices in the overall competitive Energy market in an unanticipated manner. In that respect the original form of the RMR Agreement did not unambiguously meet the third goal I have described. I will explain this problem, and how it was addressed, in the next section of my testimony.

The current RMR Agreement, put in place by FERC's approval of the Offer of Settlement of April 2, 1999, represents a major improvement over the original RMR Agreement in terms of this third goal -- avoiding effects on the remainder of the competitive market. However, this third goal still is not unambiguously met, due to the fact that current RMR protocols do not include provisions to ensure that all demand that is met through RMR Energy is "netted out" of demand that is met through the competitive market.

<u>PART II</u>

Q. What is the purpose of this part of your testimony?

A. In this section, I will describe certain aspects of the original RMR Agreement that were found to have unintended, negative effects on the competitive Energy markets. I will also describe how the RMR Agreement was modified in order to moderate those effects.

Q. Please describe those features of the original RMR Agreement that will be relevant to your discussion.

A. Originally there were three contract conditions in the RMR Agreement. These contract conditions were known as “A,” “B,” and “C.” Contract C was for RMR Units that could not be profitable in the competitive market but that had to be supported in order to be available to generate at times for reliability. Under contract C, the ISO paid all of an RMR Unit’s fixed costs and also paid its start-up and variable operating costs when it was called upon for reliability. An RMR Unit on contract C was not allowed to participate in the competitive market. Under contract A, an RMR Unit was paid by the ISO only when it was called upon to provide reliability service. When called, the RMR Unit was paid its start-up costs, if any, its variable operating costs, and a Reliability Payment. The Reliability Payment consisted of a portion of the RMR Unit’s fixed costs. Under contract B, the ISO paid all of an RMR Unit’s fixed costs “up front,” in a monthly Availability Payment that was not tied to how much the RMR Unit operated for reliability. Whenever the ISO called upon the RMR Unit for reliability, it paid the RMR Unit’s start-up costs, if any, and its variable operating costs. Unlike RMR Units on contract C, which also received their fixed costs in the form of up-front payments, RMR Units on contract B could participate in the competitive Energy and Ancillary Service markets. However, they were required to rebate to the ISO, as a credit against the Availability Payment, 90% of any net revenues they earned in the competitive markets, until they had repaid the entire annual amount of the Availability Payment, after which they could keep any net market revenues.

Q. What were the unintended consequences of these contract conditions, to which you alluded previously?

A. While contract C prevented an RMR Unit from participating in the competitive market even if, on some occasions, it might be profitable for it to do so, this was a known shortcoming of contract C from the outset and was seen as a necessary consequence of giving the RMR Unit full support payments. No unintended consequences were discovered with respect to contract C. In fact, during 1998, no RMR Unit operated under contract C.

Both contract A and contract B were found to have the unintended consequence of creating incentives for the RMR Owner either to withhold from the PX Day-Ahead Market for Energy the capacity that had been designated for RMR, or to bid that capacity into the market at supra-competitive prices (prices significantly above a unit's variable operating cost, or its opportunity cost in other markets). There were two separate problems. The first, created only by contract A, was that the Owner of an RMR Unit that received a relatively high Reliability Payment when called upon by the ISO faced a significant opportunity cost of bidding into the PX Day-Ahead Market – namely the loss of that Reliability Payment. As a consequence, when there seemed to be a reasonable chance that the ISO would have to call upon the RMR Unit, the Owner would either bid a price for the

RMR capacity into the PX Day-Ahead Market that was significantly higher than it would have bid without the potential for the RMR call, or it would even withhold the capacity from the PX market altogether and await the RMR call.

The second problem was created by both contract A and contract B, although it was more acute with contract B. This problem was given the name "portfolio effect." An Owner with both RMR capacity and non-RMR capacity in its generating portfolio had an incentive to bid the RMR capacity at a higher than competitive price in the PX Day-Ahead Market, or to withhold the capacity altogether, in an effort to influence the Market Clearing Price in that market upwards, in order to benefit its non-RMR capacity. Since contract B required the Owner to rebate 90% of its net market revenues to the ISO (until the Availability Payment had been fully repaid), the Owner suffered very little opportunity cost in bidding the RMR capacity very high or keeping the capacity out of the market: the Owner only had to forego 10% of the potential net revenue the capacity would earn if it cleared the PX Day-Ahead Market.

Q. What effect did these unintended consequences of contracts A and B have on the competitive Energy market?

A. Both the opportunity cost of bidding created by the Reliability Payment of contract A, and the "portfolio effect" associated with both contracts, but especially contract B, created incentives for the withholding of capacity (or the functional equivalent, through higher than competitive bidding) from the PX Day-Ahead Market. Such withholding decreased the amount of effective competition in that market, with the result that Market Clearing Prices could be expected to be higher than they would have been had the RMR capacity been bid at competitive prices.

Q. When and how were these problems with contracts A and B recognized?

A. They were recognized by the Department of Market Analysis ("DMA")(then known as the Market Surveillance Unit) and by the Market Surveillance Committee ("MSC"), in the late summer and fall of 1998.

Q. Could you briefly explain the purpose and function of the DMA and the MSC?

A. Both were established to monitor the operations of the markets run by the ISO and to identify any distortions in those markets and recommend solutions to deal with those distortions. The MSC is an external advisory committee composed of three members that reviews the performance of the ISO's markets and provides recommendations to the ISO and FERC regarding potential market design and policy options. The DMA is the ISO's own internal group that monitors the performance of the ISO's markets, identifies potential gaming and market design flaws, and identifies and analyzes potential market design changes. Another function of the DMA is to support the MSC with information and analysis that the MSC utilizes in developing recommendations to the ISO and FERC. Beyond the support function that the DMA provides to the MSC, the DMA and MSC are independent entities that each review market performance and provide recommendations concerning market design and market power issues.

Q. What happened after the problems were recognized?

A. The reports of the MSC and the DMA were prepared while the parties in these proceedings were negotiating possible changes in the payment mechanisms and other aspects of the RMR Agreement. In the spring of 1999, the parties involved in RMR negotiations agreed to change the RMR Agreement in ways that had the effect (among other effects) of addressing the unintended consequences that had been recognized.

Q. What changes did the parties make in the RMR Agreement?

A. The parties removed the Reliability Payment under contract A and the requirement under contract B that the RMR Owner credit back to the ISO 90% of the Owner's net market revenues from sales from the RMR capacity. The parties actually combined contracts A and B into one payment mechanism, known as condition 1. Under condition 1, the ISO pays the Owner of an RMR Unit a Monthly Availability Payment as part of a fixed, up-front payment, and also pays it, as another part of the up-front payment, the costs of all start-ups that the ISO estimates it will need during the year. When the ISO calls on the RMR Unit to run for reliability, and the Owner elects to provide this must-run generation under the RMR contract, the ISO pays the RMR Unit's variable operating costs only. When the Owner elects to provide this must-run generation through a transaction in the competitive Energy markets, it is allowed to keep all of the market revenues, with no obligation to credit anything back to the ISO.

Q. How did these changes address the problems identified with the original version of the RMR Agreement?

A. By removing the Reliability Payment and the start-up payment from the amount paid when an RMR Unit is called, the new condition 1 removed the source of the opportunity costs that a Unit under original contract A faced when it was bidding into the PX Day-Ahead Market. Now, all that the Owner of an RMR Unit receives in payment under the RMR Agreement, when a Unit is called upon to provide Energy for reliability, is the Unit's variable operating costs. In order to avoid operating at a loss, the Owner of an RMR Unit would bid into a competitive market a price at least equal to its variable operating costs (including start-up and shutdown costs), as it has to incur those costs any time it runs the Unit. Therefore, the payment the Owner will not receive from the ISO if the Unit is selected in the PX Day-Ahead Market is no greater than what the Owner would bid, at a minimum, in the PX Day-Ahead Market anyway. This means there is no opportunity cost of a competitive bid in the PX Day-Ahead Market.

The new condition 1 also addresses the disincentive to bidding that was created by the requirement under original contract B that the Owner credit to the ISO 90% of its net revenues from market operations. Now, under condition 1, the Owner keeps all revenues from market operations. This significantly changes the Owner's calculations in deciding whether it is more advantageous to bid the RMR Unit's output at a competitive price into the PX Day-Ahead Market, or instead to withhold that output in hopes of driving the PX price upwards to the benefit of the Owner's non-RMR capacity. Previously, the Owner would be foregoing only 10% of any potential net revenues if the RMR Unit were to be selected in the PX Day-Ahead Market. Now, the Owner would be foregoing *all* of any potential net revenues. This makes it much more likely that the Owner will decide, on balance, that it is in its economic interest to bid the RMR Unit's output into the PX Day-Ahead Market at a competitive price.

Q. Did the change from the original contract A and contract B to the new condition 1 create any new problems?

A. To date, neither the MSC nor the DMA has identified any unanticipated market distortions from the new condition 1, under which most RMR Units have been operating since June 1, 1999. As I noted earlier in this testimony, however, the current practice of dispatching RMR requirements after the close of the PX Day-Ahead Market (rather than prior to that Day-Ahead Market) creates significant market distortions and inefficiencies. This issue will be addressed in detail in a separate filing to modify the ISO's Tariff, which may be made shortly.

There is a practical issue embedded in the structure of condition 1, and it is the one that has spawned the hearing in which this testimony is being submitted. As I have mentioned, under condition 1 the ISO pays the Owner of an RMR Unit a Monthly Availability Payment, the amount of which depends on the Unit's availability when the ISO calls on the Unit, but not on the Unit's generation when called upon. This was not the case with the old Reliability Payment, which was designed to pay a portion of a Unit's fixed costs every time the Unit was called upon to provide Energy. This feature of condition 1 creates the need to determine *what* portion of the fixed costs the ISO should pay through the Monthly Availability Payment. The determination of the portion to be paid has been the subject of negotiations with each RMR Owner since the form of condition 1 was agreed upon. While the ISO and the transmission owning utilities who are responsible for paying the RMR costs (the "Responsible Utilities") have been able to settle the amount of this payment with some RMR Owners, it has not been possible with others, and therefore the appropriate payment to be paid by the ISO (on behalf of the Responsible Utilities) is one of the subjects of these hearings. In the next section of my testimony I will explain the nature of the ISO's objectives with respect to the amount of the fixed payment to RMR Owners, and I will present an approach to determining that payment which is supported by the ISO because it addresses the ISO's objectives.

PART III

Q. What is the purpose of this portion of your testimony?

A. In this section I will explain the objectives that the ISO seeks to achieve through the determination of the appropriate Monthly Availability Payment to be made to Owners of RMR Units, and why the approach advocated by the ISO and the Responsible Utilities meets those objectives.

Q. Please explain the ISO's objectives as they relate to the appropriate amount of the Monthly Availability Payment to RMR Owners.

A. The ISO has three separate but interweaving objectives that affect its approach to this issue. Those objectives are, first, that the payment be large enough to ensure that an RMR Unit remains available to provide Energy when necessary for reliability; second, that the payment be no more than is reasonably necessary to meet the first objective; and third, that the method of determining the payment enable the ISO to predict the total amount of RMR costs attributable to an RMR Unit, so that the ISO can conduct a process in which other units, transmission upgrades, and demand-side management proposals can compete to displace the ISO's need for the Unit.

Q. Would you please briefly explain the source and nature of each of these objectives.

A. Under the statutory framework for the restructuring of the California electricity industry, the ISO is responsible for ensuring the reliability of the ISO-controlled transmission grid. As I have noted, it is necessary at certain times for RMR Units to be generating at certain minimum levels in order to ensure that the grid remains stable. Therefore, the ISO is concerned that the fixed payment be sufficient to ensure that the RMR Units will remain open and available to operate when that is necessary.

A second consideration for the ISO is that it has a general mandate to improve the efficiency of the markets that it operates, and thus an implied mandate to keep down the costs to consumers of meeting all of its responsibilities. Thus, to the extent that it is consistent with ensuring that RMR Units remain open and available to operate when needed for reliability, the ISO has an implied obligation to keep the costs to consumers from RMR Units at a reasonable level. This objective also requires that RMR payments be limited to the incremental cost of providing these services in order to avoid potential inefficiencies that could be created by investment in alternatives for meeting local reliability requirements that cost more than the actual incremental costs of meeting local reliability requirements through RMR Units.

These points -- the ISO's general mandate to ensure reliability at lowest reasonable cost, and the need to provide proper price signals for assessment of and investment in other potential options for meeting local reliability --- lead to the ISO's third objective with respect to the manner of determining the size of the Monthly Availability Payment. The ISO annually conducts a process in which proposals for new generating units, transmission upgrades, and demand-side management are considered as potential replacements for existing RMR Units. This solicitation is conducted as part of the ISO's Local Area Reliability System ("LARS") process. The ISO conducts this solicitation in order to keep the cost of ensuring local reliability as low as reasonably possible. In order to conduct a fair and competitive process, the ISO and Market Participants must be able to estimate the costs will be incurred to keep a specific existing RMR Unit in that status. Establishing a firmer and more transparent estimate of the costs of RMR Agreements will provide market participants and the ISO with a benchmark for use in developing and assessing options that could compete against RMR Units in future LARS solicitations. Therefore, the ISO would like to see an approach to calculating the Monthly Availability Payment that it can apply with some assurance in order to estimate the ongoing costs of an RMR Unit to consumers. In making this calculation, the ISO must of course consider both the fixed payment to RMR Units, as well as the payments necessary to "make whole" RMR Owners for any difference between their variable operating cost and the real time price for Imbalance Energy they receive for Energy when they are constrained on by the ISO, and elect to receive payment under the RMR Agreement instead of meeting their generating obligation by entering into a market transaction. It should be noted that while the ISO uses the LARS solicitation to identify any cost-effective alternatives to existing RMR Agreements for meeting local reliability requirements, there may not be lower-cost alternatives in some areas, where transmission upgrades or other options are prohibitively expensive. In these cases, the existing RMR Agreement would establish the maximum that should be paid to ensure local reliability.

Q. When the ISO takes into account all of the factors that you have discussed in your previous answer, what approach to the calculation of the appropriate Monthly Availability Payment does the ISO support?

A. These considerations lead the ISO to support an approach under which the amount of the fixed payment (leaving aside payment for anticipated start-up costs) is equal to the net incremental costs imposed on a unit by virtue of its having been designated an RMR Unit. We refer to this approach as the "incremental cost" approach to setting the fixed payment.

Q. How does the ISO propose that this approach work, in practice?

A. The first step would be to determine whether an RMR Unit, absent an RMR obligation, could be expected to earn positive net revenues – or operating revenues which exceed all of the costs that the Owner must recover in order to make it economically rational for the Owner to keep the Unit operational. Those costs are the "going-forward" costs of the Unit; that is, the costs that the Owner would incur in order to keep the Unit open absent an RMR obligation. These are the only costs that the Owner can avoid by shutting down the Unit, and thus the only costs that the Owner should consider in deciding whether to keep the Unit open. ("Sunk" costs, which are the costs (such as construction or purchase costs) that were incurred in the past, would remain a burden on the Owner regardless of whether or not the Owner closed the Unit; therefore, sunk costs should not be considered in the Owner's decision of whether to keep a Unit open.)

If one determines that an RMR Unit could not be expected to recover all of its going-forward costs, the implication is that the Unit would be closed but for the obligation to remain open and to operate the Unit when needed for reliability under the RMR Agreement. Thus, in the situation in which the RMR Unit would be expected to be shut down absent an obligation to remain available to the ISO, the amount of the shortfall between fixed going-forward costs and net market revenues – or any net incremental costs --should be paid to the Owner in the Monthly Availability Payment under the RMR Agreement.

If, on the other hand, one determines that the Owner could be expected to earn all of an RMR Unit's fixed going-forward costs from the market without an RMR obligation, then the Owner should still be paid the net incremental costs as a fixed payment under the RMR Agreement. This is because the fixed going-forward costs of an RMR Unit include the additional fixed costs imposed on the Unit in order to meet the Unit's RMR obligations. These additional costs may be minor administrative costs, or they may be more major, such as the net costs incurred to keep a Unit open during a season in which it will not earn its fixed operating costs from the market and therefore would be shut down but for the RMR obligation. Whatever these additional costs may be, the Owner should be paid them through the fixed payment even if the Unit is expected to be able to recover all of its fixed going forward costs, including these RMR-imposed costs, from the market. Not to pay those net incremental RMR-imposed costs would mean that the Owner's profits from market operations would be less than they would have been had the Unit not been designated an RMR Unit. That would amount to penalizing the Owner financially for its Unit having been designated an RMR Unit.

Q. How would one determine whether there is some portion of the fixed going-forward costs of a Unit that an Owner cannot reasonably be expected to recover from operating the Unit absent an RMR obligation in the competitive markets?

A. Of course, one could simply determine what the Owner in fact recovers in net market revenues, and then subtract that amount from the RMR Unit's fixed going-forward costs. That approach, however, would mean that how the Owner bid the Unit into the market could affect the amount of the fixed payment that the Owner received from the ISO. The experience with the incentives created by the Reliability Payment under the original contract A and the credit-back requirement under the original contract B have taught the ISO and other parties to avoid payment mechanisms in which an Owner's actual behavior in the market can affect the amount of its payments under the RMR Agreement. Therefore, the better approach is to estimate what an economically rational Owner could be anticipated to make from a Unit over the course of a given year in the competitive markets absent an RMR obligation. In order to make that estimate, the ISO has developed a computer-based model, referred to as the "net market revenues" model, which estimates the anticipated market revenues of an RMR Unit absent an RMR obligation and given market prices observed in a specified time period. One then subtracts this amount from the fixed going-forward costs of an RMR Unit, and if the difference is positive, the amount of that difference is the appropriate amount of the fixed payment. The net market revenues model is discussed in the testimony of Brian Theaker.

Q. If the net market revenues model indicates that an Owner could be expected to recover all of the fixed going-forward costs of an RMR Unit from the market, the net incremental cost approach, as you have described it, would still require that the ISO pay the Owner the portion of the Unit's fixed going-forward costs that remain after netting out any incremental benefits that are attributable to the Unit's having been designated an RMR Unit. How would one determine the amount of additional fixed going-forward costs (or the net incremental fixed costs) that are imposed on a Unit by virtue of its having been designated an RMR Unit?

A. This is explained in the testimony of witnesses who are appearing on behalf of the Responsible Utilities.

Q. How does the net incremental cost approach compensate an Owner for any "opportunity costs" that it might incur from its Unit having been designated an RMR Unit?

A. Any opportunity costs are part of the "additional costs" imposed on a Unit by virtue of it being designated an RMR Unit. To the extent the RMR Owner can show that they exist and are not otherwise compensated under the RMR Agreement, they should be included as part of the fixed payment.

Q. You have stated that you believe that the incremental cost approach addresses the three objectives of the ISO that are affected by the determination of the amount of the Monthly Availability Payment. Please explain how the incremental cost approach addresses the first objective, that of ensuring that RMR Units remain open and available to be in operation to ensure local system reliability.

A. The incremental cost approach, combined with other features of the RMR Agreement, provides the Owner a reasonable opportunity to recover all of the costs that it must recover in order to keep an RMR Unit open and available to the ISO. Under accepted economic principles, an economically rational Owner would have no reason to shut down a Unit so long as the Owner is able to recover, from some source, all of its costs of keeping the Unit open (its "fixed going-forward costs") and operating it to produce Energy and/or Ancillary Services (its "variable operating costs"). The incremental cost approach, in combination with other features of the RMR Agreement (such as pre-payment for start-up costs), would give the Owner a reasonable opportunity to recover all of its fixed going forward costs and its variable operating costs.

First, under the RMR Agreement, the Owner always has the option to be paid for the variable operating costs associated with meeting an RMR dispatch requirement. The Agreement permits the Owner to participate in the Energy markets at its discretion. Presumably, the Owner will not enter into bilateral contracts at prices that fail to recover its variable operating costs, nor will it submit bids into the PX Energy markets at levels that would fail to recover those variable operating costs. When a Unit is not in the market but the ISO requires it to operate for reliability, the RMR Agreement requires the ISO to pay the Owner the variable operating costs of the Unit. The level of this variable cost payment is established for all the current Owners in the Stipulation and Agreement filed April 2, 1999. Thus, whether the Unit operates as the result of a market transaction or as the result of being called upon by the ISO, the Owner can recover the variable operating costs of the Unit.

Since the Owner will recover the variable operating costs of the Unit from the market or from the ISO, the only costs that the Owner must recover in the Monthly Availability Payment, in order to keep the Unit open, are the fixed going-forward costs. The incremental cost approach is intended to determine the portion of those fixed going-forward costs that the Owner can reasonably be expected to recover from market transactions, and to have the ISO pay the Owner, in the Monthly Availability Payment, the remainder of the fixed going-forward costs that are not reasonably expected to be recovered from the market. For RMR Units that can be reasonably expected to recover their fixed going-forward costs from market transactions, the incremental cost approach is designed to provide a payment that covers the net incremental costs of performing under an RMR contract. As I stated at the outset of this answer, if the Owner is able to recover all of a Unit's fixed going-forward costs and variable operating costs, then there is no reason for the Owner to take the Unit out of operation. Therefore, under the existing RMR Agreement and the incremental cost approach to calculating the Monthly Availability Payment, the RMR Units should be available when needed by the ISO.

Q. How does the incremental cost approach meet the ISO's second objective, that of ensuring that RMR Units are available at the lowest reasonable cost to consumers?

A. As I explained earlier, economic theory suggests that an Owner must be able to recover its fixed going-forward costs, in addition to its variable operating costs, in order to keep a Unit available for operation, and thus available to the ISO. The incremental cost approach is designed to afford the RMR Owner a reasonable opportunity to recover those fixed going-forward costs, but is also designed so that the ISO does not pay the Owner any more than is necessary to give the Owner that reasonable opportunity. As I noted earlier, the incremental cost approach also avoids the potential for stimulating investment in other options for meeting local reliability requirements that may actually cost more than the incremental cost of meeting local reliability through RMR Units.

Q. How does the incremental cost approach address the ISO's third objective, that of being able to estimate the ongoing costs to the ISO of an RMR Unit, for purposes of facilitating a solicitation for resources that might seek to displace the Unit?

A. The incremental cost approach yields a specific amount that the ISO will be required to pay, as a Monthly Availability Payment, to the owner of an RMR Unit. As noted earlier, in making this calculation, the ISO must of course consider both the fixed payment to RMR Units, as well as the payments necessary to "make whole" RMR Owners for any difference between their variable operating cost and the real time price for Imbalance Energy they receive for Energy when they are constrained on by the ISO, and elect to receive payment under the RMR Agreement instead of meeting their generating obligation by entering into a market transaction. In effect, this becomes the maximum that the ISO should pay for other options for meeting local reliability that are offered through the LARS process.

PART IV

Q. What is the purpose of this part of your testimony?

A. In this part, I will describe the ISO's recommended approach to determining the portion of the costs of ISO-approved Repairs and Capital Items at an RMR Unit that the ISO will be required to pay under an RMR Agreement.

Q. What is the approach that the ISO recommends?

A. The ISO recommends extending the concept of incremental costs to Capital Items and Repairs, using what has sometimes been called a "but for" test. Under this test, the ISO would be responsible for paying only the portion of the cost of any Repair or Capital Item that the Owner of the RMR Unit would not have made or installed "but for" the Unit's status as an RMR Unit. Of course, the ISO should receive a credit against this payment for any amount of additional net market revenues that the Owner can be expected to earn as a result of adding the portion of the Repair or Capital Item that is required solely as a result of the Unit's being an RMR Unit.

Q. Why does the ISO believe this is the correct test?

A. The Owner of an RMR Unit would make most Repairs and install most Capital Items in order to keep a Unit in the market or return it to the market, even if the Unit had not been designated an RMR Unit. The ISO – and ultimately consumers – should not have to subsidize the Owner's maintenance or improvement of the Unit for purposes of earning market revenues. Only when the Owner can establish that it would not have undertaken a Repair or installed a Capital Item, or a portion of either one, if the Unit were not an RMR Unit, should the ISO and consumers have to pay, and then only for the net amount that is attributable solely to an RMR requirement. This approach to determining the ISO's share of a Repair or Capital Item is simply another application of the "incremental" approach, and thus is consistent with the approach I have advocated for determining the amount of the Monthly Availability Payment.

CONCLUSION

Q. Does this complete your initial testimony?

A. Yes, it does.