THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, **Complainant,** **v.** **Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange,** **Respondents.**	)	**Docket No. EL00-95-045**
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	**Docket No. EL00-98-042**

PREPARED DIRECT TESTIMONY OF
DR. ERIC HILDEBRANDT ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS

A. My name is Dr. Eric Hildebrandt and I am the Manager of Market Investigations for the California Independent System Operator Corporation (“ISO”). My business address is 151 Blue Ravine Road, Folsom, CA 95630.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. As the Manager of Market Investigations, I have worked extensively on analysis of the overall performance and competitiveness of California’s

Energy[1] and Ancillary Services markets, analysis and mitigation of local market power through Reliability Must-Run ("RMR") Contracts, and development and analysis of system market power mitigation options. Over the last year, I have also worked extensively on the issue of how refunds may be determined to ensure just and reasonable outcomes for participants in California's wholesale Energy market.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold a B.S. degree in Political Economy from 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 research relating to energy issues for over thirteen years, with an emphasis on performing economic analysis, market research, and 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 in 1998, I worked for over three years at the Sacramento Municipal Utility District as Supervisor of Monitoring and Evaluation.

[1] Capitalized terms are defined in the ISO Tariff, Appendix A – Master Definitions Supplement.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE COMMISSION?

A. I have provided written and oral testimony in proceedings related to RMR contracts in California (Docket Nos. ER98-496-000, ER98-1614-000, ER2145-000 and ER99-3603). I have also submitted several reports and statements to the Commission in conjunction with previous filings by the ISO in these proceedings, including written and oral comments before Judge Wagner during the Settlement Conference on refunds held pursuant to the Commission's June 19, 2001 Market Mitigation Order[2].

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain how the ISO arrived at the mitigated price to be used in determining the amount of refunds due for transactions in the ISO and California Power Exchange ("PX") markets during the period of October 2, 2000 through June 20, 2001 (the "refund period") pursuant to the methodology set forth in the Federal Energy Regulatory Commission's ("Commission" or "FERC") July 25, 2001 Order, 96 FERC ¶ 61,120 (2001) ("July 25 Order"). The first section of my testimony provides a background description of the design and operation of the ISO's Real Time Market. The second section addresses the key provisions of the July 25 Order as well as the other Commission orders relating to calculation of the mitigated price based on the ISO's Real Time

[2] *Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference*, 95 FERC ¶ 61,418 (2001) ("June 19 Order").

Market. Subsequent sections then provide a detailed description of the methodology used by the ISO in calculating the mitigated price to be used in determining refunds.

I. DESIGN AND OPERATION OF THE ISO'S REAL TIME MARKET

Q. PLEASE DESCRIBE THE PURPOSE AND BASIC DESIGN OF THE ISO'S REAL TIME MARKET.

A. One of the ISO's key responsibilities is to ensure a balance between load and generation in the ISO Control Area in real-time. The ISO's Tariff and Operating Protocols are designed to allow the ISO to rely, whenever possible, on competitive market mechanisms to perform this balancing of load and generation to ensure system reliability. The ISO's Real Time Market for Imbalance Energy is an essential mechanism whereby the ISO controls the actual dispatch of resources to ensure the reliability of the transmission grid that it operates. [3]

The ISO's market design rules require that all entities participating directly in the California wholesale market interact with the ISO as Scheduling Coordinators ("SCs"). The ISO Tariff requires SCs to submit schedules on

[3] The ISO Tariff defines "Real Time Market" as "the competitive generation market controlled and coordinated by the ISO for arranging real time Imbalance Energy." ISO Tariff, Appendix A – Master Definition Supplement, Original Sheet No. 341.

a Day-Ahead and Hour-Ahead basis that are "balanced," meaning that they include an equal amount of scheduled load and generation. *See* ISO Tariff § 2.2.7.2. In real time, however, actual loads often deviate from scheduled generation for a number of reasons. For example, generation may deviate from schedules unintentionally (due to outages and ramping constraints), as well as intentionally, in response to real time prices. Similarly, actual loads often deviate from Day Ahead and Hour Ahead load schedules due to load forecast error, as well as "under-scheduling" of expected load by buyers in response to the price and quantity of supply offered in various markets prior to real time.

The ISO's primary mechanism for maintaining a balance between loads and generation in real time is the Real Time Market, which involves the dispatch of Generating Units based on real time Energy bid prices through the Balancing Energy and Ex-Post Pricing ("BEEP") system.[4] If increased supply is needed to match actual loads with generation (i.e., demand exceeds supply in real time), bids for additional generation (or *incremental* energy) are selected in increasing order of price (or "merit order") and dispatched through the BEEP system. If decreased supply is needed to match actual loads with generation (i.e., supply exceeds demand in real time), bids to decrease generation (or *decremental* energy) are selected in

[4] "BEEP Software" is defined in the ISO Tariff as "the balancing energy and ex post pricing software which is used by the ISO to determine which Ancillary Service and Supplemental Energy resources to Dispatch and calculate the Ex Post Prices." ISO Tariff, Appendix A – Master Definitions Supplement, Sheet No. 307

decreasing order of price through the BEEP system. Bids for decremental energy submitted by Generating Units within the ISO system represent the price suppliers are willing to pay in order to reduce their operating levels and, in effect, buy Energy in the Real Time Market. Decremental bids submitted by resources outside the ISO Control Area also represent bids to buy real time Energy, but may represent either a decrease in Energy imports scheduled into the ISO system or an increase in Energy exports from the ISO system.

Q. WHAT TYPES OF BIDS ARE AVAILABLE FOR DISPATCH THROUGH THE ISO'S BEEP SYSTEM?

A. Bids available for dispatch through the BEEP system include the bids for incremental Energy that must be submitted for all capacity that is scheduled to provide the following Ancillary Services: Spinning, Non-Spinning and Replacement Reserve. In addition, bids eligible for dispatch through the BEEP system include Supplemental Energy bids for incremental and decremental Energy submitted by resources within and outside of the ISO system. Supplemental Energy bids of incremental Energy represent any uncommitted capacity available from these resources following the finalization of the Hour-Ahead Schedules that suppliers choose to bid into the Real Time Market. Since Energy bids from Ancillary Services capacity represent incremental Energy, the only resources available in the BEEP system for decreasing or decrementing generation are those that have submitted Supplemental Energy bids for decremental energy

Q. HOW DOES THE ISO IDENTIFY THE GENERATING RESOURCE ASSOCIATED WITH ENERGY BIDS SUBMITTED INTO ITS REAL TIME MARKET?

A. Bids for generating resources within the ISO Control Area are submitted under resource identification codes (or "Unit ID's") used in scheduling, each of which represents a specific physical Generating Unit or resource in the ISO's Control Area. However, all real time Energy bids from sources *outside* the Control Area are identified only in terms of the transmission inter-tie over which they are delivered, the Scheduling Coordinator submitting the bid, and an "Interchange ID" that may contain some general information about the source of the bid. However, with respect to bids from sources outside of the ISO's Control Area, the ISO is generally unable to determine the individual Generating Unit or even the resource type that will produce the Energy pursuant to such a bid.

Q. HOW IS THE PRICE OF ENERGY IN THE ISO'S REAL TIME MARKET ESTABLISHED?

A. Supplemental Energy and Ancillary Service energy bids are submitted to the ISO's Real Time Market for each operating hour. The BEEP system then ranks these bids in merit order based on price in order to create a supply curve of real time Energy, commonly referred to as the “BEEP stack.” Bids in the BEEP stack are dispatched though BEEP on a 10-minute basis (each of these 10-minute periods is known as an “interval”). Additionally, the BEEP system establishes real-time Imbalance Energy prices every 10 minutes based on the real-time Energy bid of the marginal unit dispatched to meet the system imbalance in that 10-minute interval. For example, if the ISO is incrementing the Energy to balance supply and demand in real time, the highest bid for incremental Imbalance Energy actually selected by the BEEP system for dispatch during a 10-minute interval is $100/MWh, then the real-time price for incremental energy for that interval is set at $100/MWh and all units dispatched for incremental Energy during that 10-minute interval are paid that price. If the ISO is decrementing generation to balance supply and demand in real time, then the real-time price for decremental energy is set at the lowest bid for decremental Imbalance Energy selected by the BEEP system for dispatch that 10-minute interval, and all units disptached for decremental Energy during that interval are paid that price.

Each 10-minute interval, the ISO establishes two different Market Clearing Prices (or “MCPs”) for real time Energy: one price based on the highest incremental Energy bid dispatched (commonly referred to as the incremental MCP or the “inc price”), and another price based on the lowest decremental Energy bid dispatched (commonly referred to as the decremental MCP or the “dec price”). If the ISO is only incrementing resources, the decremental MCP is set equal to the MCP for incremental Energy. Likewise, if the ISO is only decrementing resources, the incremental MCP is set equal to the MCP for decremental Energy. These two MCPs are used for the financial settlement of Imbalance Energy provided in response to BEEP dispatch instructions (or Instructed Energy), as well as Uninstructed Energy provided when units deviate from their final Hour-Ahead Energy Schedules, as described later in my testimony.

In the absence of real-time Congestion between the ISO’s active Zones (SP15, NP15 and ZP26), the BEEP prices apply to all real-time Imbalance Energy system-wide. However, when real-time Inter-Zonal Congestion occurs, the BEEP stack is constructed and applied separately for each Zone and produces different prices for the zones on either side of the constrained zonal interface. In this situation, the ISO frequently needs to decrement resources in one zone, while incrementing resources in the other zones to mitigate this Congestion.

Q. ARE THERE OTHER SOURCES FROM WHICH THE ISO PURCHASES ENERGY IN ORDER TO MEET UNSCHEDULED DEMAND?

A. Yes. There are six other sources from which the ISO may purchase Energy that can ultimately assist in meeting demand that is not met by supply scheduled on a Day Ahead or Hour Ahead basis with the ISO.

These include: (1) residual Imbalance Energy, (2) Regulation Energy from units under Automated Generation Control ("AGC"), (3) real time Energy bids dispatched out of merit order – referred to as out-of-sequence ("OOS") transactions, (4) calls for additional real time Energy from RMR units, (5) out-of-market ("OOM") purchases that may be made just prior to or during real time to ensure adequate System Reliability, and (6) Uninstructed Imbalance Energy or "positive uninstructed deviations." However, unlike the bids for real time Energy which are dispatched through the BEEP system, these transactions are not eligible to set the MCP in the ISO's Real Time Market.

Q. WHAT IS RESIDUAL IMBALANCE ENERGY?

A. Residual Imbalance Energy represents Imbalance Energy generated as a result of a dispatch instruction issued during a previous 10-minute interval, which is not re-issued in a subsequent interval. Due to ramping constraints, for instance, a unit dispatched for Instructed Imbalance Energy in one interval may need to continue to generate some additional Imbalance Energy during one or more subsequent intervals during which this energy bid is not "re-dispatched" by the ISO. Under the ISO's settlement process, generators are compensated for this energy based on the Market Clearing Price ("MCP") for the interval in which this Energy was last dispatched. However, residual Imbalance Energy is not included in the determination of the MCP for any subsequent intervals during which this bid is not “re-dispatched” by the ISO.

Q. WHAT IS REGULATION ENERGY FROM UNITS ON AUTOMATED GENERATION CONTROL?

A. The ISO purchases capacity in the Day-Ahead and Hour-Ahead Ancillary Service auctions from units under AGC which can be used to provide both upward and downward Regulation. The ISO controls the output of units providing this Regulation capacity (within a prescribed operating range) in response to changes in system frequency and tie-line loading so as to maintain system frequency within acceptable target levels. Units providing Regulation are not ramped up or down in any specific merit order, but are controlled by the ISO as needed to best manage system conditions. In the settlement process, any Energy resulting from the operation of units to provide Regulation services is treated as Uninstructed Imbalance Energy and is not used in the determination of the real time MCP. Thus, units being paid to provide Regulation capacity are, in effect, required to be “price takers” in the Real Time Market, and are paid or charged the Real Time Market price for any incremental or decremental Energy they provide as a result of being ramped up or down by the ISO to balance system load and generation.

Q. WHAT ARE REAL TIME RMR CALLS?

A. In real time, the ISO may sometimes need to call for additional Energy from units under RMR contracts in order to ensure local area reliability. However, these calls for additional real time Energy from RMR units are relatively rare due to the fact that the ISO's Tariff is designed so that the level of Energy needed from RMR units is generally projected and scheduled prior to real time operations. Pursuant to Amendment 26 to the ISO Tariff, the minimum operating level required from each RMR unit in order to ensure local area reliability (or "minimum reliability requirements") is projected on a Day-Ahead basis by the ISO (a process known as "pre-dispatch"). After receiving this pre-dispatch notice, RMR unit operators may elect to be paid based either on market prices (the "market path") or based on a pre-determined formula for calculating variable operating costs (the "contract path"). In either case, Energy needed to meet this minimum operating requirement must be scheduled against demand prior to real time. If conditions in real time require additional Energy from an RMR unit to ensure local are reliability, an RMR "schedule change" may be issued to ensure that the RMR unit operates in real time at the required level. Payment for any real time RMR dispatches are made either at the real time MCP or based on the unit's variable operating costs, depending on the option (market path or contract path) selected by the RMR operator prior to real time.

Q. WHAT ARE OUT-OF-SEQUENCE ("OOS") PURCHASES?

A. Bids submitted into the ISO's BEEP stack may also be called upon to mitigate real-time Intra-Zonal Congestion (Congestion within Zones due to local transmission constraints) and other local reliability problems that may not be mitigated through RMR disptaches. In this situation, Energy bids from a limited number of individual generating units or locations on the grid must typically be taken out of economic merit order (or out-of-sequence) in order to mitigate Congestion within a Zone or to ensure some other aspect of System Reliability. Units dispatched out-of-sequence are paid the bid price for Energy they provide. However, because these bids are not selected based on their economic merit order within the overall supply of real time Energy, they are not eligible to establish the overall MCP in the Real Time Market.

Q. WHAT ARE OUT-OF-MARKET ("OOM") PURCHASES?

A. Out-of-market ("OOM") purchases represent purchases made by the ISO outside of the automated BEEP system in order to relieve locational constraints and/or to ensure adequate System Reliability. OOM purchases may be made from resources both inside and outside of the ISO's Control Area.

Under the ISO's Tariff, the ISO has the authority to issue generation dispatch instructions to any resource within the ISO Control Area under a

Participating Generator Agreement ("PGA") in order to ensure adequate System Reliability. If a unit in this situation has already bid into the ISO's Real Time Market, the ISO may call these bids out-of-sequence and pay those units based on their bid price, as described above. However, if a generating unit has not already bid into the ISO's Real Time Market, the ISO may issue an out-of-market instruction to that unit directing it to generate. Under the ISO Tariff, Participating Generators (i.e., those units with a PGA) may select from two forms of payment for Energy provided pursuant to OOM calls: Option A provides for payment at the real time MCP, while Option B provides for payment pursuant to a pre-determined cost-based formula. During the refund period, the total amount of energy purchased through OOM or OOS calls from gas-fired Generating Units within the ISO Control Area was relatively limited. For example, settlement transaction data provided to participants in this proceeding reveal that only about 8% of OOM and OOS energy purchased over the refund period was from gas fired units within the ISO Control Area.

During the refund period, most of the Energy purchased out-of-market represents imports from outside the ISO's Control Area. Settlement transaction data provided to participants in this proceeding reveal that imports accounted for approximately 88% of Energy purchased through OOM and OOS calls during this period. In addition, since December of 2000, virtually all imports have been purchased out-of-market.

These trends reflect a combination of at least two major factors. First, when the ISO projects that resources bid into the Real Time Market might be insufficient to meet demand, the ISO typically seeks to procure additional Energy from resources outside of the ISO Control Area to ensure adequate System Reliability. Since purchases of imports must often be made early in an operating day or shortly prior to the beginning of an operating hour in order to ensure delivery during periods of tight supply, these purchases have often been made out-of-market prior to real time. Second, as concerns relating to the creditworthiness of the state's major utilities developed beginning in December of 2000, an increasing number of sellers outside the ISO Control Area began to require direct payment for any Energy provided. As a result, the California Department of Water Resources ("CDWR"), acting as a creditworthy buyer on behalf of the ISO, began to procure significant amounts of Energy out-of-market from suppliers outside the ISO Control Area starting in December of 2000.

Q. WHAT IS UNINSTRUCTED IMBALANCE ENERGY?

A. Uninstructed Imbalance Energy or "deviation" Energy results when a unit deviates from its scheduled operating level, and instead generates at a higher or lower level. The ISO calculates Uninstructed Imbalance Energy as part of the settlement process by comparing metered generation levels with each unit's scheduled operating level. The scheduled operating level used in this calculation includes the unit's Final Hour-Ahead Energy schedule, plus any real time Energy instructions issued through BEEP, any residual Imbalance Energy, and any OOS or OOM calls issued by the ISO. When the amount of metered generation is greater than a unit's scheduled operating level, this difference is known as a positive uninstructed deviation. When the amount of metered generation is less than a unit's scheduled operating level, this difference is known as a negative uninstructed deviation. In the ISO's settlement process, the net deviation of each Scheduling Coordinator ("SC") is calculated for each 10-minute interval by summing up the deviations of all supply resources and demand points in the SC's portfolio. SCs with net positive deviations during a 10-minute interval are paid the real-time MCP for incremental Imbalance Energy established during that interval (the "inc price"), while SCs with net negative deviations are charged the real time MCP for decremental Imbalance Energy established during that interval (the "dec price"). Energy from uninstructed deviations do not represent competitive "bids," and therefore have no role in setting the Market Clearing Price ("MCP") for real-time Imbalance Energy; rather, these deviations are treated as "price takers," meaning they are paid or pay the MCP as determined in the Real Time Market described above.

II. KEY PROVISIONS OF THE COMMISSION'S MARKET MITIGATION ORDERS

Q. PLEASE SUMMARIZE THE COMMISSION'S RULINGS WITH RESPECT TO REFUNDS IN THE JULY 25 ORDER.

A. In the July 25 Order, the Commission established the scope of and methodology for calculating refunds for transactions in the spot markets operated by the ISO and the PX during the refund period. As to the scope of refunds, the Commission concluded that all public and non-public sellers in the PX and ISO spot markets (including OOM purchases by the ISO) would be subject to refund liability, with two exceptions: (1) sales involving bilateral transactions by CDWR, and (2) sales made pursuant to orders issued by the Secretary of Energy were excluded from refund liability under the July 25 Order. With respect to the methodology to be used in calculating refunds, the Commission adopted the recommendations of the Chief Administrative Law Judge ("Chief Judge") as set forth in his July 12, 2001 Report and Recommendation of the Chief Judge and Certification of Record, 96 FERC ¶ 63,007 (2001) ("July 12 Report and Recommendation"), with several minor modifications. Finally, the Commission ordered that an evidentiary hearing be convened by Administrative Law Judge Birchman, and directed Judge Birchman to make findings of fact with respect to "(1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established [in the July 25 Order]; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the ISO, the investor owned utilities, and the State of California." July 25 Order at 61,520. Additionally, in order to begin development of the factual record for this hearing, the Commission ordered the ISO to "provide Judge Birchman with a re-creation of the mitigated prices that result from using the methodology described [in the July 25 Order] for every hour from October 2, 2000 through June 20, 2001." *Id.* The Commission also directed the ISO and PX to rerun their settlement and billing processes, applying the mitigated prices to transactions that occurred in their respective markets during the refund period, and to provide this data to Judge Birchman as well. *Id.*

Q. PLEASE DESCRIBE THE REFUND METHODOLOGY RECOMMENDED BY THE CHIEF JUDGE IN HIS JULY 12, 2001 REPORT AND RECOMMENDATION, WHICH THE COMMISSION BASICALLY ADOPTED IN ITS JULY 25 ORDER.

A. The Chief Judge recommended that in order to "re-create the outcome of a competitive market . . . the methodology set forth in the [Commission's June 19, 2001 Order should] be used with [certain modifications] in order to calculate any potential refunds that may be due to customers in the CAISO's and Cal PX's spot energy and ancillary service markets for the period October 2, 2000 through May 28, 2001." 96 FERC at 65,039-40.

The Chief Judge explained that the June 19 Order "established a mitigated price based on the marginal cost of the last unit dispatched to meet load in the CAISO's real-time imbalance energy market," and that the "actual heat rates associated with recreating the must bid requirement of the June 19 Order, provide the first step in calculating the cost of the marginal unit." *Id*. at 65,040.

Next, in a departure from the methodology used in the June 19 Order (which I describe later), the Chief Judge recommended that gas costs for the marginal unit be based on daily spot gas prices, rather than closing prices for monthly gas contracts. Consistent with the June 19 Order, the Chief Judge also proposed the addition of $6/MWh to the calculated mitigated price to cover generator operating and maintenance expenses, and recommended that emissions costs be excluded from the mitigated price "and treated as an additional expense that sellers may subtract from their respective refund calculation." *Id.* at 65,041. The Chief Judge also proposed applying the 10 percent adder established in the June 19 Order retroactively in calculating the mitigated price for transactions subsequent to January 5, 2001 to reflect uncertainty concerning the creditworthiness of California's two largest Investor Owned Utilities. *Id.* at 65,040.

Q. SINCE THE CHIEF JUDGE'S RECOMMENDATIONS WERE BASED ON THE JUNE 19 ORDER EXCEPT FOR THE MODIFICATIONS YOU HAVE NOTED, PLEASE DESCRIBE THE COMMISSION'S METHODOLOGY FOR CALCULATING MITIGATED PRICES AS SET FORTH IN THE JUNE 19 ORDER.

The mitigated price methodology in the June 19 Order was largely based on the methodology established in the Commission's April 26, 2001 Order,[5] with certain modifications.

In the April 26 Order, the Commission had required the ISO to "establish a market clearing auction for real-time markets" that would involve price mitigation for all generators in California during periods of reserve deficiency (when operating reserves in the ISO's Control Area drop below 7%) by using "competitive bids in the ISO auction to replicate competitive pricing." *Id.* at 61,358. This price mitigation methodology required that the ISO calculate, for each generator subject to price mitigation, a marginal cost that would serve as a proxy bid for that generator. The Commission required that each gas-fired generator in California file heat and emission rate data for each Generating Unit with the Commission and the ISO. The ISO would then use those heat rates to "calculate a marginal cost for each generator by using a proxy for the gas costs, emission cost, and a $2.00

adder for operation and maintenance expenses." *Id*. at 61,359. During emergency conditions, the ISO was directed to set the MCP at the marginal price of the "highest priced unit dispatched calculated using the proxy price." *Id*. Under the April 26 Order, gas-fired generators may submit bids greater than their proxy bid price. However, these bids may not set the MCP and are subject to cost verification and refund if selected and dispatched. All other bids are paid a single MCP reflecting the highest proxy bid from gas-fired units dispatched.

In the June 19 Order, the Commission affirmed the use of the marginal cost of the last unit dispatched to establish the mitigated price, reasoning that "using the marginal cost of the least efficient generating unit dispatched best replicates prices in a competitive market." 95 FERC at 62,560. However, the Commission made four modifications to the methodology for calculating the mitigated price. First, it modified the procedure for calculating the proxy cost for gas. Whereas the April 26 Order required that gas costs be calculated based on prices published for daily spot markets, the June 19 Order required that gas costs be based on an index of prices published for monthly gas contracts. The Commission also decided to eliminate emissions costs from the calculation of the mitigated price, directing the ISO to develop a separate emission allowance administrative charge to be assessed against all in-state load

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[5] *Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale*

served on the ISO's transmission system. Third, the Commission increased the $2/MWh adder for operation and maintenance expenses established in the April 26 Order to $6/MWh. Finally, the June 19 Order established a 10 percent adder to be applied to the mitigated market price to reflect uncertainty concerning the creditworthiness of California's two largest Investor Owned Utilities (Southern California Edison Company and Pacific Gas & Electric Company).

Most significantly, however, the June 19 Order expanded the scope of the price mitigation adopted in the April 26 Order in two important ways. First, the June 19 Order required that the mitigated price methodology be applied to spot transactions in the ISO and PX markets during all hours, rather than only during periods of reserve deficiency. Second, the June 19 Order expanded this price mitigation methodology to the entire Western regional market by establishing a region wide price cap in spot markets based on the mitigated price limit set in the ISO's Real Time Market. This second modification ensures that any OOM purchases that may have been made by the ISO are subject to the same price mitigation measures as purchases made through the ISO's formal bid-based market (i.e. the "BEEP stack").

Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets, 95 FERC ¶ 61,115 (2001) ("April 26 Order").

Q. PLEASE SUMMARIZE THE PROCEDURE THAT THE COMMISSION, IN THE JULY 25 ORDER, DIRECTED THE ISO TO FOLLOW IN DETERMINING THE MITIGATED PRICE FOR PURPOSES OF THE REFUND CALCULATION, TAKING INTO ACCOUNT THAT ORDER'S HAVING ADOPTED THE FUNDAMENTAL APPROACH OF TWO PREVIOUS COMMISSION ORDERS (APRIL 26 AND JUNE 19) AND THE CHIEF JUDGE'S RECOMMENDATIONS.

A. Under the methodology recommended by the Chief Judge and adopted by the Commission in the July 25 Order, the ISO was required to "re-create the outcome of a competitive market," by calculating a mitigated price based on the "marginal cost of the last unit dispatched." 96 FERC at 65,039-40. The Commission in the July 25 Order explained that the ISO should determine the last unit dispatched (i.e., the marginal unit) "by selecting from the actual units dispatched in real-time the maximum heat rate of any unit dispatched each hour in the real-time imbalance market . . ." 96 FERC at 61,517. Therefore, as explained in detail below, the ISO, in its procedure for identifying the marginal unit, only considered those units whose bids were eligible to set the MCP in the ISO's Real Time Market for Imbalance Energy.

Additionally, in the April 26 Order, the Commission specified that only gas-fired units in California were required to submit heat rate data to the ISO, and thus, only gas-fired units dispatched by the ISO could set the mitigated real time MCP. The June 19 Order did not modify this requirement, and the methodology recommended by the Chief Judge and adopted by the Commission in the July 25 Order included numerous consistent references to heat rates and gas costs to be used in determining the mitigated price for purposes of calculating refunds. Therefore, the ISO included only gas-fired generating units in its mitigated price calculation.

As noted above, the April 26 Order required that heat rate data for all gas-fired units within California be submitted to both the ISO and the Commission. The April 26 and June 19 Orders further required that this heat rate data be used in calculating proxy bids and mitigated market prices as specified in these orders. Shortly thereafter, the Chief Judge's July 12 Report and Recommendation stated that "[t]he CAISO has the actual heat rate for every hour of the last unit dispatched in the CAISO's real-time imbalance energy market," and that these "actual heat rates . . . provide the first step in calculating the cost of the marginal unit." 95 FERC at 65,040. Therefore, the ISO used the heat rate data supplied by generators pursuant to the April 26 Order in order to identify the marginal unit. As discussed in further detail in the testimony of Mark Rothleder, the ISO's method for collecting and applying heat rate data in calculations of the mitigated or "proxy" price was explicitly approved by the Commission in its June 19 Order.

After identifying the marginal unit for each interval based on the heat rates of units dispatched in the ISO's real time market, the ISO was required by the Commission in the July 25 Order, consistent with the Chief Judge's recommendation, to calculate the marginal cost of that unit by multiplying the unit's heat rate by a proxy price for gas based on the region in which the unit was located (Northern or Southern California). Consistent with the June 19 Order, the ISO was then required to calculate the total operating costs of the marginal unit by including $6/MWh for operating and maintenance expenses, but directed to exclude any emissions costs. Additionally, in order to reflect credit uncertainty, the ISO was directed to include a 10% adder for those intervals subsequent to January 5, 2001.

Finally, the Commission's July 25 Order directed the ISO to "substitute the revised market clearing prices calculated for each 10-minute period in its settlement software." 96 FERC at 61,517 n. 68. The ISO was also required to "take the average of the maximum heat rates for the six 10-minute periods in order to develop a market clearing price for application in the hourly auctions," which include the ISO's Ancillary Service capacity markets and the PX Day-Ahead and Hour Ahead Markets for Energy. *Id.* Therefore, for purposes of determining refund liabilities, the ISO directly applied the mitigated prices calculated for each 10-minute interval to transactions for Imbalance Energy during the corresponding 10-minute interval. However, the ISO also calculated the simple average of the mitigated prices for the six intervals during each hour in order to develop a single mitigated hourly price for use in calculating refunds relating to transactions occurring in the ISO's Ancillary Service capacity markets and the PX Energy markets. The July 25 Order also reaffirmed that the "mitigated price" to be used in the ISO and PX's settlement "re-runs" should be applied as a price cap, which would establish the maximum price with refunds for transactions over this level.

III. CALCULATION OF THE MITIGATED MARKET PRICE

Q. PLEASE SUMMARIZE THE ISO'S PROCESS FOR CALCULATING THE MITIGATED PRICE TO BE USED IN DETERMINING REFUNDS.

A. The process by which the ISO calculated the mitigated price involved four distinct steps. First, the ISO calculated the marginal heat rate of each gas-fired unit bid and dispatched in the ISO's Real Time Market for every 10-minute interval during the refund period. Second, the marginal gas-fired unit dispatched in the Real Time Market during each 10-minute interval was identified, based on the marginal heat rates calculated in the first step. Third, the marginal operating cost of the marginal unit during each 10-minute interval was calculated based on daily spot market gas price indices, along with variable operating and maintenance costs of

$6/MWh, and a 10% credit risk adder was applied to that operating cost for intervals after January 5, 2001. Fourth, the simple average of the marginal prices calculated for each of the six 10-minute intervals within each hour was calculated to arrive at a maximum hourly mitigated price to be used in determining refunds in markets with hourly auctions, such as the ISO's Ancillary Service capacity and PX Energy markets.

Q. WHAT DATA WAS USED BY THE ISO IN CALCULATING THE MITIGATED PRICE?

A. In order to calculate the mitigated price during each hour, several sets of data were utilized. First, the ISO calculated incremental heat rates for all gas-fired units within the ISO Control Area based on the average heat rate data submitted to the ISO by the owner/operator of each unit, pursuant to the April 26 Order. A detailed description of this calculation, including a list of these units and their average and incremental heat rates, is set forth in the Direct Testimony of Mark Rothleder. Second, the ISO utilized its own records of Final Hour-Ahead Schedules submitted by each generator to the ISO, plus real time Energy bids and dispatches made through the ISO's BEEP system. Finally, the analysis utilized gas price indices for Northern and Southern California calculated from daily spot market gas prices reported in various publications for various delivery points, as specified in the July 25 Order. A description of how these gas price indices were calculated and a listing of these prices is provided in the Direct Testimony of Mark Rothleder.

<u>A. Step One – Calculation of Gas-Fired Generating Unit Heat Rates</u>

Q. WHAT WAS THE FIRST STEP IN THE ISO'S CALCULATION OF THE MITIGATED PRICE?

A. The first step in determining the mitigated price involved calculating the actual heat rates for all gas-fired units bid into the ISO's Real Time Market for each 10-minute interval. The incremental heat rate curves (representing incremental heat rates at different operating points) used in this analysis were developed by the ISO based on the average heat rate data filed by generators with the Commission and the ISO pursuant to the April 26 Order, as described in the Direct Testimony of Mark Rothleder. However, since heat rates often vary depending on the operating level of a unit, this step of the analysis required the ISO to select one specific incremental heat rate (or "segment" of a unit's incremental heat rate curve) to represent the actual incremental heat rate of the unit during each 10-minute interval based on the unit's actual operating level.

Q. HOW DID THE ISO UTILIZE THE INCREMENTAL HEAT RATE CURVES TO DETERMINE THE ACTUAL HEAT RATES FOR GENERATING UNITS DURING EACH 10-MINUTE INTERVAL?

A. The actual incremental heat rates for gas-fired units dispatched during each 10-minute interval were calculated based on the Acknowledged Operating Target (“AOT”) for each gas-fired unit during each interval. The AOT is defined as the Final Hour-Ahead Schedule for Energy submitted for each unit, plus any real-time Energy dispatched by the ISO during that hour. The exact mathematical formula for this calculation is provided in Exhibit ISO-2.

Figure 1.
Calculation of Generating Unit Heat Rates
Based on Acknowledged Operating Target (AOT)

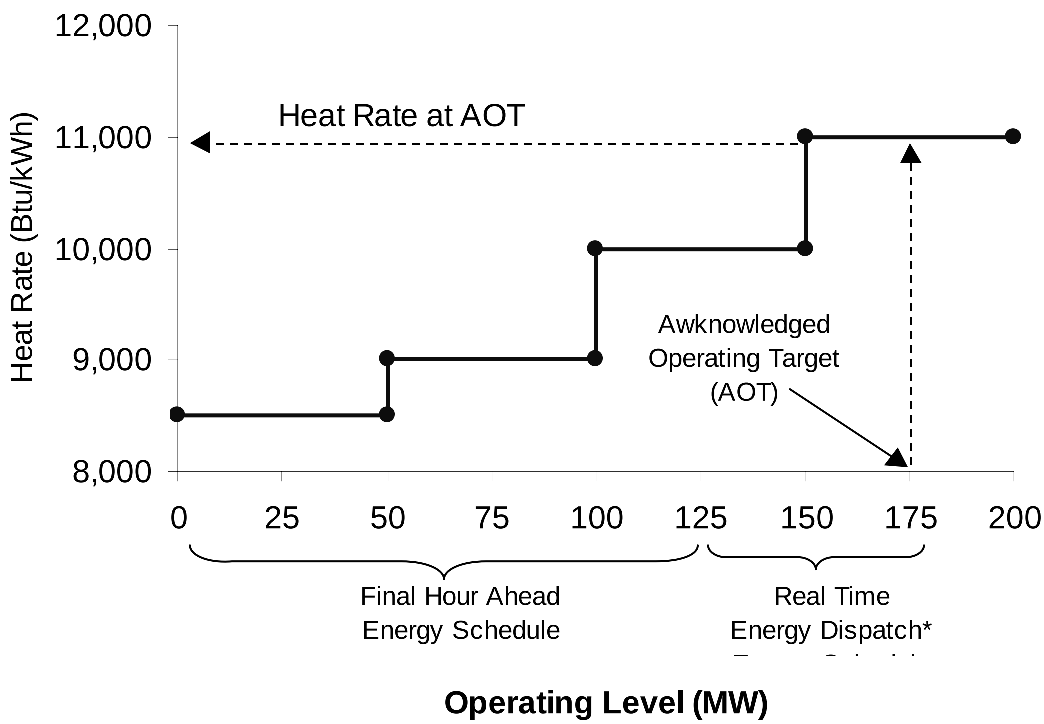


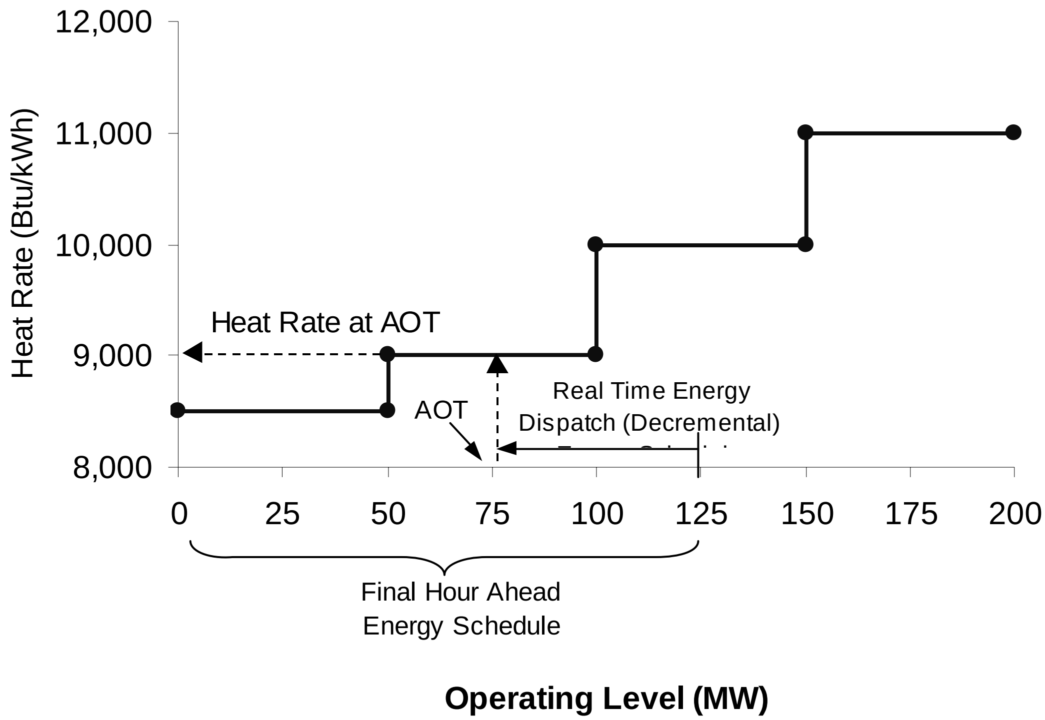
Figure 1 illustrates how the heat rate of a gas-fired unit is calculated based on the AOT of that unit for a 10-minute interval. First, the AOT for the unit is determined by adding the unit's Final Hour-Ahead Schedule with the total amount of Energy dispatched through the ISO's BEEP system. Once the AOT is determined, the heat rate of the unit at that operating point is calculated based on the segment of the unit's incremental heat rate curve corresponding to the operating level represented by the AOT.

In this example, the Final Hour-Ahead Schedule submitted to the ISO by the unit's SC for this hour is 125 MW. During one of the 10-minute intervals of that hour, real-time Energy bids for an additional 50 MW of incremental Imbalance Energy are accepted by the ISO. In this example it is assumed that upon receiving a real time dispatch from the ISO, the unit operator "acknowledges" that it will deliver the 50 MW instructed. Thus, the unit's total AOT for this 10-minute interval is 175 MW (125 MW + 50 MW), and its heat rate at that operating level is 11,000 Btu/kWh.

Q. HOW DID THE ISO CALCULATE THE ACKNOWLEDGED OPERATING TARGET AND CORRESPONDING HEAT RATE FOR UNITS DISPATCHED FOR DECREMENTAL ENERGY?

A. Figure 2 illustrates how the AOT and corresponding heat rate is calculated for units that are dispatched for *decremental* (rather than incremental) energy during a particular interval.

Figure 2.
Calculation of Generating Unit Heat Rates
Based on Acknowledged Operating Target (AOT)

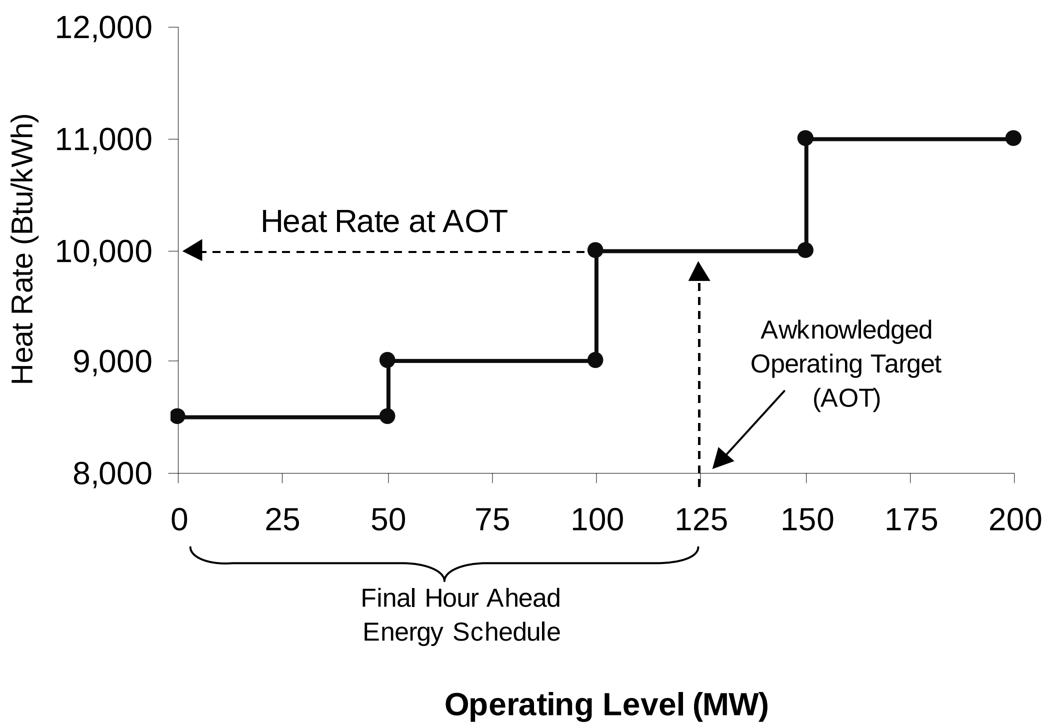


In this example, the Final Hour-Ahead Schedule submitted to the ISO by the unit's SC for this hour is 125 MW. During one of the 10-minute intervals of that hour, real time Energy bids for 50 MW of decremental Imbalance Energy are accepted by the ISO (and subsequently "acknowledged" by the operator). Thus, the unit's total AOT for this 10-minute interval is 75 MW (125 MW - 50 MW), and its heat rate at that operating level is 9,000 Btu/kWh.

Q. HOW DID THE ISO CALCULATE THE ACKNOWLEDGED OPERATING TARGET AND CORRESPONDING HEAT RATE FOR UNITS NOT DISPATCHED FOR EITHER INCREMENTAL OR DECREMENTAL ENERGY?

A. Figure 3 illustrates how the AOT and corresponding heat rate is calculated in cases where units are bid into the real time Energy market for incremental Imbalance Energy, but are not dispatched for either *incremental* or *decremental* Imbalance Energy.

Figure 3.
Calculation of Generating Unit Heat Rates
Based on Acknowledged Operating Target (AOT)



In this example, the Final Hour-Ahead Schedule submitted to the ISO by the unit's SC for this hour is 125 MW. Thus, for any 10-minute interval during that hour when none of the unit's bids for incremental or decremental Imbalance Energy are dispatched by the ISO, the unit's total AOT is 125 MW. The unit's heat rate at that operating level is 10,000 Btu/kWh.

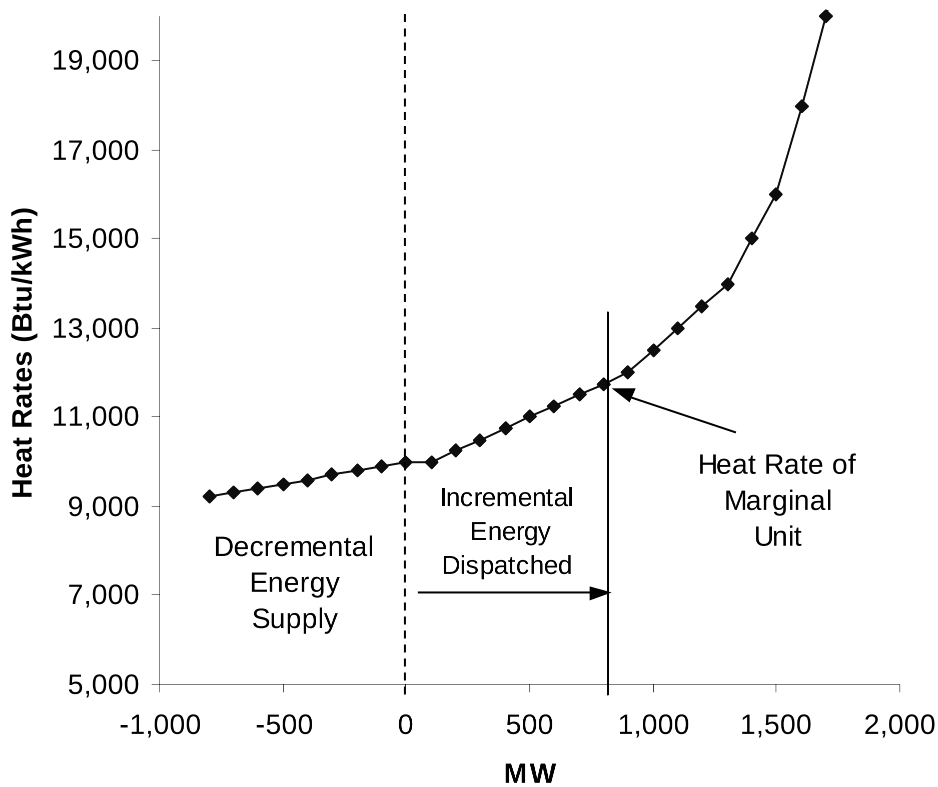
B. Step Two – Calculation of the Marginal Gas-Fired Unit

Q. HOW DID THE ISO CALCULATE THE MARGINAL GAS-FIRED UNIT FOR EACH 10-MINUTE INTERVAL?

A. This step begins by taking the incremental heat rate values for each unit during each interval that were calculated in the first stage of this analysis. In this second step of the analysis, the ISO calculated the marginal unit during each 10-minute interval using the following three-step process or set of decision rules:

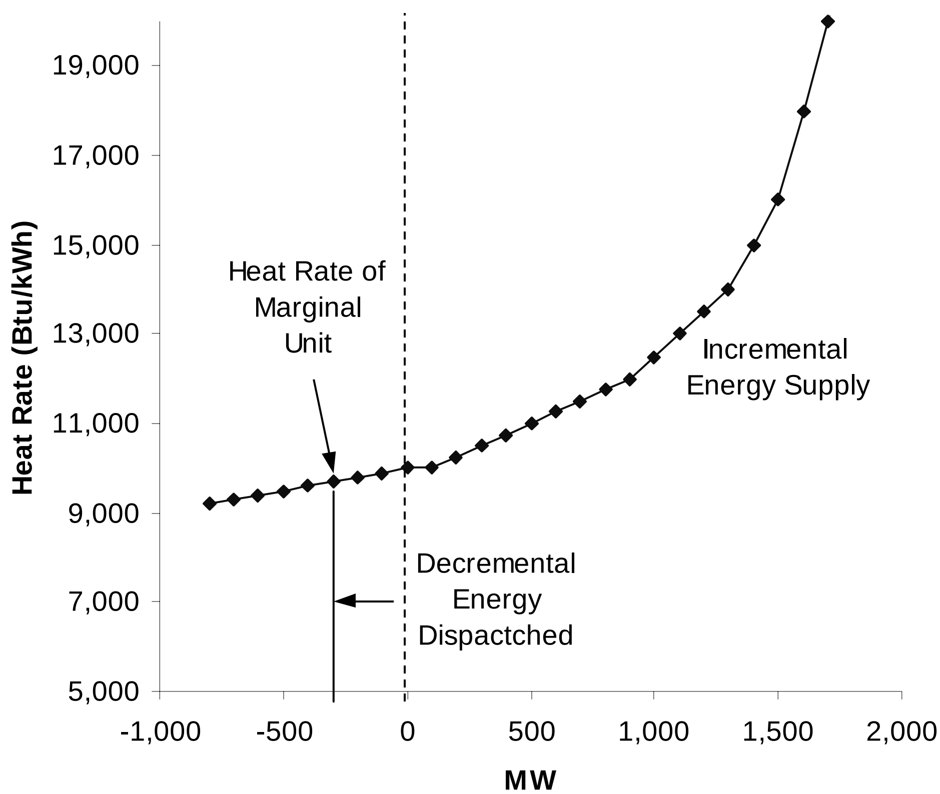
a) First, if one or more bids for incremental Imbalance Energy were accepted by the ISO's BEEP Software and the resulting dispatch instruction was "acknowledged" by the unit's operator, then the marginal incremental unit was derived from the *highest* incremental heat rate of all gas units with an acknowledged incremental dispatch instruction during that interval. This situation is illustrated in Figure 4.

Figure 4. Heat Rate of Marginal Gas-Fired Unit Dispatched for Incremental Energy



b) Second, if no gas unit had an acknowledged incremental dispatch instruction during the interval, but one or more gas units had a decremental dispatch instruction, the marginal unit was derived from the *lowest* heat rate of the gas units with an acknowledged dispatch instruction for decremental Imbalance Energy during the interval. In this situation, the lowest heat rate of units dispatched for decremental Imbalance Energy represents the marginal gas-fired unit available to meet demand, as illustrated in Figure 5. For instance, if one additional MW of supply had been needed during these intervals, the lowest heat rate of the gas-fired units decremented by the ISO represents the *marginal* (or last) unit that would have been dispatched to balance supply and demand in real time.

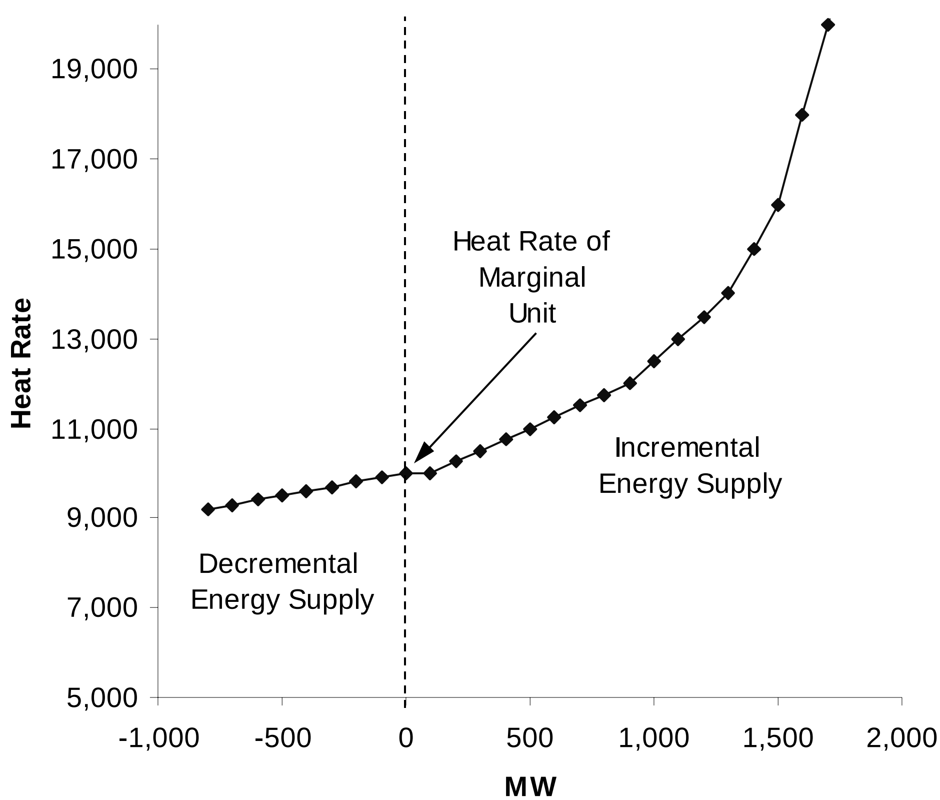
Figure 5. Heat Rate of Marginal Gas-Fired Unit Dispatched for Decremental Energy



c) Finally, if no gas unit had either an acknowledged incremental or an acknowledged decremental dispatch instruction during the interval, the marginal unit was derived from the *lowest* incremental heat rate of all units with bids for incremental real time energy bids submitted to the ISO. As noted above, the supply of real time Energy bids available for dispatch (the "BEEP stack") for a 10-minute interval consists of all Energy bids from units providing Spinning, Non-Spinning, or

Replacement Reserve capacity, as well as Supplemental Energy bids submitted during the hour containing that interval. In the situation in which no gas unit had either an acknowledged incremental or an acknowledged decremental dispatch instruction during an interval, the lowest heat rate of units with incremental Imbalance Energy bids represents the marginal gas unit available to meet demand. As illustrated in Figure 6, if one additional MW of supply had been needed during these time intervals, the lowest heat rate of the gas-fired units with unused bids in the ISO's Real Time Market represents the *marginal* gas unit that could have been dispatched in order to balance supply and demand in real time.

Figure 6. Heat Rate of Marginal Gas-Fired Unit When No Gas-fired Unit is Dispatched for Incremental or Decremental Energy



Q. DURING INTERVALS IN WHICH THERE WERE NO ACKNOWLEDGED INCREMENTAL DISPATCHES, BUT UNITS WERE DISPATCHED FOR DECREMENTAL ENERGY, WHY DID THE ISO CALCULATE THE MARGINAL UNIT BASED ON THE LOWEST INCREMENTAL HEAT RATE OF ALL UNITS WITH AN ACKNOWLEDGED DECREMENTAL DISPATCH DURING THOSE INTERVALS?

A. The July 25 Order required the ISO to identify the marginal unit during each interval based on the "last unit dispatched" by the ISO. 96 FERC at 61,517. As described previously in my testimony, dispatches of decremental energy represent a situation in which the ISO, in effect, sells excess Imbalance Energy back to Scheduling Co-ordinators that express their willingness to reduce generation (or increase demand) through Supplemental Energy bids for decremental energy. When responding to a decremental instruction, gas-fired units reduce their output below their previously scheduled level (typically equal to their Final Hour-Ahead Energy Schedule), and are charged the decremental MCP in that interval for the decremental energy (or reduction in generation below their previously scheduled level) that is delivered pursuant to this instruction.

Under the ISO's Tariff, decremental dispatch instructions are issued in merit order of their bid price in *descending* order, and the decremental MCP is determined by the last acknowledged bid in the sequence, which is the *lowest* of all bids selected. *See* ISO Tariff § 2.5.23.1. Thus, the lowest decremental bid represents the "last unit dispatched" in this situation. Because the marginal unit in this situation is derived based on the lowest bid accepted, it is appropriate to identify the marginal unit for purposes of the mitigated price calculation under the July 25 Order based on the lowest incremental heat rate for all gas-fired units dispatched for decremental energy in the ISO's Real Time Market during those intervals in which no gas-fired unit was dispatched for incremental Imbalance Energy.

Q. DURING INTERVALS IN WHICH THERE WERE NO ACKNOWLEDGED INCREMENTAL OR DECREMENTAL DISPATCHES, WHY DID THE ISO CALCULATE THE MARGINAL UNIT BASED ON THE LOWEST INCREMENTAL HEAT RATE OF ALL UNITS WITH A REAL TIME ENERGY BID DURING THOSE INTERVALS?

A. Again, the July 25 Order requires that the marginal unit be identified based on the "last unit dispatched" by the ISO in each interval. 96 FERC at 61,517. During intervals when no gas-fired unit was dispatched in the ISO's Real Time Market, it is still necessary to calculate a mitigated price for use in determining refunds for other Energy and Ancillary Service transactions pursuant to the July 25 Order. Under the ISO's Tariff, the ISO accepts bids for incremental Imbalance Energy in economic merit order (in ascending order of price). Thus, for purposes of determining the marginal gas unit for those intervals in which no gas-fired unit was dispatched in the ISO's Real Time Market, the lowest incremental heat rate of gas units with bids into the ISO's Real Time Market represents the best indication of the marginal gas unit that could be dispatched to meet demand, since this unit could have been called on first by the ISO's BEEP system had there been a need for incremental Imbalance Energy. This approach reflects how the ISO's BEEP software is designed to calculate the incremental MCP for Real Time Energy in the event that no units are dispatched through BEEP during any interval. This approach is also consistent with the standard economic principles that (1) marginal costs are the costs of producing one unit more (or less) and (2) under competitive market conditions, market clearing prices in uniform price auctions should equal the marginal costs of the last increment of supply needed to meet demand.

Q. WHY DID THE ISO CALCULATE THE MITIGATED PRICE BASED ONLY ON DISPATCHES AND BIDS OF GAS-FIRED UNITS WITH PARTICIPATING GENERATOR AGREEMENTS FOR WHICH HEAT RATE INFORMATION HAD BEEN SUBMITTED TO THE ISO PURSUANT TO THE APRIL 26 ORDER?

A. The ISO's calculation of the mitigated price was based only on gas-fired units with Participating Generator Agreements ("PGAs") for several reasons.

First, the mitigated price methodology, as originally established in the April 26 Order, limited the ISO's consideration to "gas-fired generator[s] in California." This element of the mitigated price calculation was not revised in the June 19 Order. Moreover, the Chief Judge's Report and Recommendation and the July 25 Order contained numerous references to heat rates and costs to be used in determining the mitigated price for purposes of calculating refunds, but did not in any way indicate that non-gas-fired units should be used in the mitigated price calculation. Therefore, the ISO has determined that this limitation still applies to its mitigated price calculation undertaken for the purposes of calculating refunds pursuant to the July 25 Order.

The ISO calculated the mitigated price based only on those gas-fired units with PGAs because only units that have executed a PGA are eligible to bid into and set the MCP in the ISO's Real Time Market. As I explained previously in my testimony, the ISO's mitigated price calculation is based only on bids that could set the MCP in the ISO's Real Time Market if dispatched by the ISO. In addition, as a practical matter, the ISO cannot identify the individual units that are the source of Energy that is bid from resources without a PGA. Therefore, the ISO has no way of determining the heat rates associated with these bids so as to include them in the calculation of the marginal unit.

Q. IN ITS CALCULATION OF THE MARGINAL PRICE, DID THE ISO CONSIDER ALL GAS-FIRED UNITS WITH PARTICIPATING GENERATOR AGREEMENTS AS ELIGIBLE FOR DESIGNATION AS THE MARGINAL UNIT, REGARDLESS OF THE TYPE OF BID SUBMITTED BY THOSE UNITS?

A. No. For purposes of calculating the marginal unit for each interval during the refund period, the ISO assumed that the "real-time imbalance market" was limited to those units whose dispatches of bids could set the MCP in the ISO's Real Time Market if dispatched by the ISO.

Q. WHY DID THE ISO LIMIT ITS CONSIDERATION TO THOSE UNITS WHOSE DISPATCHES OR BIDS WERE ELIGIBLE TO SET THE MARKET CLEARING PRICE?

A. The ISO proceeded in this manner based on the language contained in the July 25 Order and the various Commission market mitigation orders leading up to that order, as well as the Chief Judge's July 12 Report and Recommendation, combined with the structure of the ISO's markets as described in its Tariff.

Q. WHAT LANGUAGE IN THE COMMISSION'S MARKET MITIGATION ORDERS INDICATED THAT THE ISO SHOULD RESTRICT ITS MITIGATED PRICE CALCULATION TO UNITS WITH DISPATCHES OR BIDS THAT WERE ELIGIBLE TO SET THE MARKET CLEARING PRICE?

A. In the July 25 Order, the Commission stated that the ISO was to "determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real-time the maximum heat rate of any unit dispatched each hour *in the real-time imbalance market*." 96 FERC ¶ 61,120 at 61,517 (emphasis added). This statement echoes one made by the Chief Judge in his July 12 Report and Recommendation, in which he recommended the adoption of the mitigated price methodology set forth in the June 19 Order, namely that the "mitigated price [be] based on the marginal cost of the last unit dispatched to meet load in the CAISO's real-time market." 96 FERC at 65,039-40.

Moreover, the various Commission orders addressing market mitigation have stressed the importance of recreating the outcome of a competitive market. For example, in the April 26 Order, the Commission explained that it was replacing the previous mitigation scheme, which capped prices at $150/MWh, with a plan that would "not be based on inflexible price caps, but on the use of competitive bids in the ISO auction *to replicate competitive pricing*." 95 FERC at 61,358 (emphasis added). Additionally, in its June 19 Order, the Commission stated that, in adopting its market mitigation plan, it had "sought to provide prices that emulate closely those that would result in a competitive market . . . ." 95 FERC at 62,564. Indeed, in that Order, the Commission declined to adopt cost-of-service rate making, explaining that it would "focus on changes to the existing market structure, rather than on cost-of-service rates for individual sellers . . . ." *Id.* at 62,558 In the July 25 Order, the Commission continued this theme by rejecting a proposal to apply to those transactions subject to refund the rule, established in the June 19 Order for forward-looking price mitigation, that prices in non-reserve deficiency hours could not exceed 85% of the mitigated price established in the last reserve deficiency hour, reasoning that this could "distort re-creation of a competitive market" and emphasizing the need to "calculate a competitive price for every hour of the period in question." 96 FERC at 61,517.

Q. WHAT IS IT ABOUT THE STRUCTURE OF THE ISO'S MARKETS, WHEN VIEWED IN LIGHT OF THE LANGUAGE DISCUSSED ABOVE, THAT CONFIRMS THE ISO'S OBLIGATION TO RESTRICT ITS MITIGATED PRICE CALCULATION TO UNITS WITH DISPATCHES OR BIDS ELIGIBLE TO SET THE MARKET CLEARING PRICE?

A. Although the ISO Tariff provides for several categories of Imbalance Energy, *the only competitive market* for real-time Imbalance Energy for those units that are able to respond to the ISO's request for more or less energy is the market for Instructed Imbalance Energy bids dispatched in sequence (i.e., in merit order) through the ISO's BEEP Software. As noted above, this "Instructed Imbalance Energy" can take the form of either incremental or decremental bids and dispatches. Section 2.5.23.1 of the ISO Tariff states that the general principle for pricing *all* Imbalance Energy is that "Instructed and Uninstructed Imbalance Energy shall be priced using the BEEP Interval Ex-Post Prices," and that the BEEP price shall be based on the "marginal" resource dispatched by the ISO to *increase or reduce demand for energy* (i.e., the marginal resource dispatched by the ISO for Instructed Imbalance Energy). Additionally, the ISO's Scheduling Protocol ("SP") specifically limits bids that may set the MCP if dispatched through BEEP to include only bids for Ancillary Service Energy (except for Regulation) and bids for Supplemental Energy. ISO SP § 11. While the ISO Tariff allows the ISO to issue dispatch instructions for purposes of "planned and unplanned transmission facility outages; bid insufficiency in the Ancillary Services and Real Time Energy markets; and location specific requirements of the ISO," these dispatches are made outside of the ISO's formal Instructed Imbalance Energy market. ISO Tariff § 11.2.4.2.1. Therefore, restricting the eligibility to set the mitigated price to units with bids for Supplemental Energy and Energy from Ancillary Services (except for Regulation) satisfies the Commission's directive that the mitigated price methodology be based on the ISO's real time imbalance market, and that it replicate competitive market results as closely as possible.

Q. WHAT SOURCES OF IMBALANCE ENERGY WERE NOT INCLUDED IN THE ISO'S MITIGATED PRICE CALCULATION?

A. There are six sources of Energy that the ISO may use to help meet unscheduled demand, but were not included in the calculation of the mitigated price. These include: (1) residual Imbalance Energy (2) Regulation Energy from units under AGC, (3) real time Energy bids dispatched out of merit order (i.e., out-of-sequence or "OOS" calls), (4) calls for additional real time Energy from RMR units, (5) OOM purchases that may be made just prior to or during real time to ensure adequate System Reliability, and (6) Uninstructed Imbalance Energy (i.e., "positive uninstructed deviations").

Q. WERE UNITS PER SE EXCLUDED FROM BEING THE MARGINAL UNIT IF THEY PROVIDED ANY OF THESE SOURCES OF ENERGY EVEN IF THEY ALSO HAD BEEN BID INTO OR DISPATCHED THROUGH THE BEEP SYSTEM?

No. These sources of energy were simply not included in the calculation of the mitigated price; the mitigated price was calculated based on all units with Energy bids into and dispatches made through the BEEP system.

For example, if a gas unit provided one or more of these sources of Energy, but was *not* bid or dispatched to provide any additional incremental or decremental Imbalance Energy through the BEEP system during that 10-minute interval, the ISO's methodology did not include the unit in the pool of units used to identify the marginal unit dispatched by the ISO.

Q. WHY WERE THESE SOURCES OF IMBALANCE ENERGY NOT INCLUDED IN THE ISO'S MITIGATED PRICE CALCULATION?

First, as previously noted, each of these sources of Energy is excluded from setting the MCP in the ISO's Real Time Market under the ISO's Tariff. In addition, however, economic principles dictate that each of these sources of Energy should be excluded from any calculation of the "marginal" or last unit dispatched to meet load in the ISO's real time market:

1. Residual Imbalance Energy results from a dispatch during a previous interval and is not part of the process of merit order dispatch through which system demand is met during each interval. Therefore, residual Imbalance Energy should not be used to determine the "marginal" resource needed to meet the last increment of system demand.

2. Units providing Regulation service are not ramped up or down in any specific "merit order," but are controlled in order to best manage system conditions. Thus, it would be inappropriate to include Regulation Energy in any calculation of the "marginal" unit in the ISO's Real Time Market.

3. Out-of-sequence calls are issued in order to address locational constraints (independent of overall system demand). Therefore, it is inappropriate to include energy provided in response to an out-of-sequence call in determining the marginal resources needed to meet the system demand.

4. Similarly, any energy provided under RMR contracts to ensure local reliability cannot be considered in determining the marginal resource needed to meet system demand, since this energy is being provided to meet locational requirements rather than overall system demand. As described previously in my testimony, Amendment 26 to the ISO's Tariff is designed to ensure that the level of energy needed from RMR units is "pre-dispatched" by the ISO and scheduled by generators prior to real time operations. In approving Amendment 26, the Commission upheld the principle that energy provided by RMR units to ensure local area reliability should in effect be "netted out" of system demand prior to

calculation of system-wide market clearing prices. Under Amendment 26, any pre-dispatched energy that Generators are not able to schedule prior to real time must be delivered into the Imbalance Energy market as a price-taker (i.e. at a price of zero or as uninstructed energy) and therefore could never set the MCP. If conditions in real time require additional energy from an RMR unit to ensure local reliability, the ISO may also issue an RMR "schedule change" to ensure that the RMR unit operates in real time at or above the minimum required level. However, payment for additional energy provided in response to any RMR schedule changes necessary to ensure local reliability are made either at the real-time market-clearing price or based on the unit's variable operating costs, depending on the option (market path or contract path) selected by the RMR operator prior to real time.

5. As previously noted, most OOM purchases are made from resources outside of the ISO's Control Area, which therefore cannot be tied to any specific gas generating resource. Thus, most OOM purchases were excluded simply because the ISO could not confirm that the energy delivered pursuant to these calls was generated by gas-fired resources. The relatively small number of OOM calls from gas-fired units within the ISO Control Area were excluded on the basis that these were typically needed to ensure

adequate System Reliability, due to either locational constraints or overall system conditions and uncertainties. When OOM calls are issued to units due to local constraints (independent of system demand), these units cannot be considered the "marginal" resources needed to meet the last increment of system demand, and are therefore disqualified to set the MCP. In cases where OOM calls may be made for overall system conditions (i.e., a general lack of supply scheduled or bid into the market), whether the resources were inside or outside the ISO's Control Area, competitive market conditions did not exist for procurement of these resources. Moreover, when the ISO is forced to issue OOM calls to units within the Control Area, the ISO frequently calls specific units as much as one day in advance and issues an OOM call for only the unit's minimum operating level, simply to ensure that the unit will be in operation when it may be needed for System Reliability. Thus, both the ISO Tariff and economic theory indicate that it would be inappropriate to include units that were only called out-of-market during a particular interval in any calculation of the "marginal" unit in the ISO's Real Time Market for that interval.[6]

6. Energy resulting from uninstructed deviations is not generated in response to an ISO instruction, and does not reflect the economic

[6] In some cases, a unit may be called out-of-market and also dispatched through the ISO's BEEP

merit order of system resources dispatched to meet demand. Thus, it would be inappropriate to include Energy from uninstructed deviations in any calculation of the "marginal" unit in the ISO's Real Time Market.

Q. HAS THE ISO PREVIOUSLY ARTICULATED ITS POSITION BEFORE THE COMMISSION THAT THE MITIGATED PRICE CALCULATION SHOULD BE LIMITED TO THOSE UNITS ELIGIBLE TO SET THE MCP IN THE ISO'S REAL TIME MARKET?

A. Yes. In its compliance filings and implementation of both the April 26 and June 19 Orders, the ISO has indicated to the Commission that it equates the mitigated real time price referenced in these Orders with the real time price established based on those units dispatched (in merit order) through the ISO's BEEP system, which represents the only true "real-time imbalance market." For example, the ISO's May 11 compliance filing included Tariff revisions clearly indicating that:

> [T]he BEEP Interval Ex Post price shall not exceed the highest Proxy Price calculated . . . . for a gas-fired unit that . . . . is dispatched by the ISO to provide Imbalance Energy," and that "[t]his Proxy Price shall establish the Market Clearing Price (the "Marginal Proxy Clearing Price") …
>
> Tariff Revisions submitted with May 11 Compliance Filing, Section 2.5.23.3.1, Docket Nos. EL00-95-000, *et al.*, filed on May 11, 2001.

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system during a particular interval. In such cases, the ISO included that unit in its determination of the marginal unit, but based only on the Energy dispatched through the BEEP system.

A subsequent Status Report submitted on May 18 also clearly described the ISO's position that the mitigated real time price referenced in the April 26 Order was to be based on the real time price established by the cost-based bids of gas-fired units dispatched (in merit order) through the ISO's BEEP system. Moreover, the May 18 Status Report specifically requested that:

> To the extent that the Commission believes that the ISO misinterpreted the Commission's order or disagrees with any aspect of the ISO's planned approach, the ISO requests that the commission notify the ISO immediately so that it can make the necessary modifications to its implementation plan, thereby minimizing any further delay in implementing an automated and tested system.
>
> Status Report to Update the Commission on the California Independent System Operator Corporation's Progress Towards Implementation of the Commission's April 26 Order, Docket Nos. EL00-95-012, *et al*., filed on May 18, 2001 at 10.

On May 25, the Commission issued its "Order Providing Clarification and Preliminary Guidance on Implementation of Mitigation and Monitoring Plan for the California Wholesale Electric Market." 95 FERC ¶ 61,275 (2001) ("May 25 Order"). This Order clarified a variety of other issues, but did not modify any of the assumptions or details relating to the ISO's procedure for calculating the mitigated price pursuant to the April 26 Order.

Following the June 19 Order, the ISO submitted compliance filing pursuant to that Order, explicitly stating that:

> The ISO equates the "hourly clearing price" referenced in the June 19 Order to the ISO's Hourly Ex Post Price. As the Commission is aware, prices in the Real Time Imbalance Energy market are established every ten minutes (the Balancing Energy and Ex Post Price Interval, or "BEEP Interval" price). These BEEP Interval prices then serve as the basis for the Hourly Ex Post Price. The Hourly Ex Post Price is defined in the ISO Tariff as the price charged or paid to Scheduling Coordinators responsible for Participating Generators and Participating Buyers for Imbalance energy and is equal to the Energy-weighted average of the BEEP Interval Ex Post Prices . . . . "
>
> Compliance Filing on June 19 Order, Docket Nos. EL00-95-000, *et al*., filed on July 10, 2001, at 14-15, n.15.

To date, the Commission has neither stated nor suggested that the ISO's interpretation as to this issue is in any way flawed. This is especially telling in light of the fact that the ISO has now been operating its markets using this interpretation of the Commission's mitigated price calculation methodology for over four months.

Q. WAS PHYSICAL WITHHOLDING OF CAPACITY THAT MAY HAVE BEEN AVAILABLE BUT NOT BID INTO THE ISO'S REAL TIME MARKET FACTORED INTO THE ISO'S MITIGATED PRICE ANALYSIS?

A. No. During the refund period, not all thermal capacity available to Market Participants was bid into the ISO's Real Time Market. Although the June 19 Order addressed the problem of physical withholding by including a "must offer" requirement, the July 25 Order rejected the argument that the impact of such "physical withholding" should be factored into the determination of the mitigated price for the refund period. The Commission explained that because it "did not institute the must offer requirement or the marginal bidding requirement until May 28, 2001, . . . it [would be] unreasonable to re-create the markets to apply such requirements for the period October 2, 2001 through June 20, 2001." 96 FERC at 61,517.

<u>C. Step Three – Calculation of Operating Costs for the Marginal Unit</u>

Q. HOW DID THE ISO CALCULATE OPERATING COSTS FOR THE MARGINAL UNIT?

A. The ISO calculated the operating costs, consisting of fuel costs and operating and maintenance expenses, for the marginal gas-fired unit for each interval using the method set forth by the Commission in the July 25 Order.

Q. HOW WERE FUEL COSTS FOR THE MARGINAL UNIT DETERMINED BY THE ISO?

A. Fuel costs were calculated by multiplying the incremental heat rate of the marginal unit by the daily spot market gas costs calculated consistent with the July 25 Order. If the marginal unit was in the ISO's northern zone (NP15), then the average daily midpoint price for the Marlin and PG&E Citygate delivery points was used. If the marginal unit was in one of the

ISO's southern zones (SP15 or ZP26), then the South California large packages midpoint gas price was used. This calculation is discussed in greater detail in the Direct Testimony of Mark Rothleder.

Q. HOW DID THE ISO ACCOUNT FOR OPERATING AND MAINTENANCE EXPENSES FOR THE MARGINAL UNIT?

A. The ISO used an assumed variable figure of $6/MWh, which was added to the cost calculated for the marginal unit to account for operating and maintenance expenses incurred by that unit. The ISO did so pursuant to the explicit instructions of the Commission in the July 25 Order. Therein, the Commission noted that the June 19 Order had established a $6/MWh adder for operating and maintenance expenses to be included in the mitigated price, that the Chief Judge had recommended the same adder be included in the methodology for calculating refunds, and that it would "therefore adopt its use in the [refund calculation] methodology." 96 FERC at 61,519.

Q. WHAT PROVISIONS FOR CREDITWORTHINESS DID THE ISO INCLUDE IN ITS MARGINAL PRICE CALCULATION?

A. Beginning on January 5, 2001, the mitigated prices calculated by the ISO, based on operating costs using the procedures explained in the previous steps, were increased by 10% to reflect the "creditworthiness adder" specified in the July 25 Order. Therein, the Commission stated that "the inclusion of a creditworthiness adder in the methodology to determine refund liability is appropriate and necessary . . . . [t]herefore, we will adopt the recommendation of the Chief Judge that the 10 percent adder should be included in the market clearing price." 96 FERC at 61,519. However, the Commission explained that it would "limit the adder to all transactions that occurred after the downgrade of SoCal Edison and PG&E's bond ratings on January 5, 2001." *Id.*

D. Step Four – Calculation of a Single Mitigated Price for Each Hour

Q. WHAT WAS THE FINAL STEP TAKEN BY THE ISO IN CALCULATING THE MITIGATED PRICE?

A. For purposes of determining the mitigated price applicable to hourly markets, the ISO calculated the simple arithmetical average of the mitigated prices calculated for the six 10-minute intervals during each hour. The ISO did so based on the July 25 Order, which requires that for periods subsequent to when the ISO instituted 10-minute settlements, that the ISO "take the average of the maximum heat rates for the six 10-minute periods in order to develop a market clearing price for application to the hourly auctions (including the PX markets)." 96 FERC at 61,517, n. 68. In practice, hourly markets covered under the July 25 Order include the PX markets, as well as the ISO's Ancillary Service capacity market. Because the ISO implemented 10-minute settlements in September 2000, this averaging of 10-mintue interval results was performed for the entire period covered by the July 25 Order. Thus, in order to calculate an hourly price for the PX and Ancillary Service markets, the ISO calculated the simple arithmetical average of the total operating costs of the marginal gas units for each 10-minute interval in order to yield a single mitigated price for each hour.

For purposes of determining the mitigated price for the ISO's transactions in real time, the ISO employed the 10-minute interval prices that were the direct result of its mitigated price calculation described above. The ISO did so based on the Commission's instruction in the July 25 Order that "for the purposes of rerunning the settlement/billing process in the imbalance market, we direct the ISO to substitute the revised market clearing prices calculated for each 10-minute period in its settlement software." *Id.*

<u>V. RESULTS OF THE MITIGATED PRICE CALCULATIONS</u>

Q. HOW HAS THE ISO PROVIDED THE RESULTS OF ITS MITIGATED PRICE CALCULATIONS?

A. The results of the ISO's mitigated price calculations for each 10-minute interval are contained in a spreadsheet that is attached as Exhibit ISO-3. This spreadsheet also displays the identification code of the marginal unit calculated for each interval, its incremental heat rate, the calculated gas price used to determine its fuel costs, its total operating costs, and the addition of the 10% creditworthiness adder after January 5, 2001. The average mitigated price calculated for use in determining refunds in hourly markets, such as the ISO Ancillary Service capacity and the PX Day Ahead Energy markets, are contained in a spreadsheet that is attached as Exhibit ISO-4. These are the prices that the ISO is using to rerun its settlements system for relevant transactions occurring during the refund period. The ISO has also provided these prices to the PX for use in that entity's calculation of mitigated prices for its markets and in its settlement rerun process.[7]

Q. IN APPLYING THE MITIGATED PRICE TO TRANSACTIONS DURING THE REFUND PERIOD, DID THE ISO USE THE MITIGATED PRICE AS A "CAP" ON TRANSACTIONS, OR DID THE ISO RESET THE PRICE OF EACH OF THESE TRANSACTIONS TO THE MITIGATED PRICE?

A. In applying the mitigated price to transactions for purposes of determining refunds, the ISO applied the mitigated price as a "cap" on transaction prices, rather than resetting the price of these transactions to the mitigated price. The results of this procedure can be illustrated by several examples:

[7] The Presiding Judge and parties should be aware that the mitigated prices included in Exhibits ISO-3 and ISO-4 are slightly different from the mitigated prices originally calculated by the ISO and distributed to participants in this proceeding on August 9, 2001. These differences reflect several corrections made by the ISO subsequent to the original calculation and distribution of these prices, as well as the simple arithmetical averaging of the 10-minute intervals instead of the weighted averaging used in the calculations distributed on August 9.

1) Assume that the ISO's Imbalance Energy market during a particular interval cleared at $250/MWh, but that the ISO determined the mitigated price during that interval to be $200/MWh. A seller bid into the imbalance market at $100/MWh during that interval, was dispatched by the ISO, and was paid the $250/MWh clearing price. The seller would be subject to refunds in the amount of $50/MWh (the historical price, $250/MWh, minus the mitigated price, $200/MWh).

2) Assume that the ISO's Imbalance Energy market during a particular interval cleared at $150/MWh, but that the ISO determined the mitigated price during that interval to be $200/MWh. A seller bid into the market at $100/MWh during that interval, was dispatched by the ISO, and was paid the $150/MWh clearing price. The seller would not be subject to any refund liability relating to this transaction, but at the same time, *would not* receive the additional $50/MWh differential between the historical clearing price and the mitigated price.

Q. WHY DID THE ISO TREAT THE MITIGATED PRICE AS A PRICE CAP IN APPLYING THAT PRICE TO HISTORICAL TRANSACTIONS?

A. The ISO applied the mitigated price as a cap to transactions during the refund period as described above based on the Commission's explicit instructions in the July 25 Order. Therein, the Commission stated clearly that "the hourly mitigated price established in the hearing" would "establish the maximum price with refunds for transactions over this level." 96 FERC at 61,515.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.