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
MARK ROTHLEDER ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

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

A. My name is Mark Rothleder, P.E. and I am the Manager of Market Integration 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. Since joining the ISO over five years ago, I have worked extensively on implementing and integrating the approved market rules for California's competitive Energy[1] and Ancillary Services markets, and the rules for Congestion Management, into the operations of the ISO Control Area. Most recently, I have played a lead role in the design and implementation of market rules, operating procedures and software modifications related to the Federal Energy Regulatory Commission's (the "Commission's") Market Mitigation Orders issued on April 26, 2001, 95 FERC ¶ 61,115, (2001) ("April 26 Order") and June 19, 2001, 95 FERC ¶ 61,418 (2001) ("June 19 Order").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold a B.S. degree in Electrical Engineering from the California State University, Sacramento. I have taken post-graduate coursework in Power System Engineering from Santa Clara University and in Information Systems from the University of Phoenix. I am a registered Professional Electrical Engineer in the state of California. I have co-authored articles on aspects of the California market design in professional journals and have frequently presented to industry forums. Prior to joining the ISO in 1997, I worked for nine years in the Electric Transmission Department of Pacific Gas & Electric Company, where my responsibilities included Operations Engineering, Transmission Planning and Substation Design.

[1] Capitalized terms are defined in the Master Definitions Supplement to the ISO Tariff.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will explain the process by which the ISO calculated incremental heat rates for gas-fired Generating Units associated with Generators that are subject to price mitigation in the ISO's markets pursuant to the Commission's April 26 and June 19 Orders. These incremental heat rates, calculated from average heat rate curves submitted by the Generators themselves, are used (along with assumptions about gas costs and other variable operating costs) to generate "proxy bids," which are substituted for bids submitted by Generators in the ISO's software system used to dispatch real time Energy when cost-based mitigation of prices is in effect under the April 26 and June 19 Orders. The same incremental heat rates were also used by the ISO to calculate the mitigated prices for the October 2, 2000 through June 20, 2001 period (the "refund period") pursuant to the methodology set forth by the Commission in its July 25, 2001 order establishing this proceeding, 96 FERC ¶ 61,120 (2001) ("July 25 Order").

I also explain in this testimony the process by which the ISO calculated the gas proxy price to be used in calculating mitigated prices under the July 25 Order.

The first portion of my testimony provides a background description addressing certain key concepts relating to heat rate calculations for Generating Units. The second section addresses the provisions of the July 25 Order and the other Commission orders relating to the calculation of heat rates and the gas proxy price. Subsequent sections then provide a detailed description of the process used by the ISO in calculating incremental heat rates and gas proxy prices for Generating Units associated with Generators subject to refund liability under the July 25 Order.

I. BACKGROUND INFORMATION ON HEAT RATE CALCULATIONS

Q. PLEASE EXPLAIN WHAT A "HEAT RATE" IS.

A. Heat rates represent the method by which the fuel consumption of electric Generating Units is commonly measured, much like the fuel efficiency of an automobile is expressed in terms of "miles per gallon." The heat rate of a gas-fired Generating Unit expresses the efficiency of the unit in transforming thermal energy into electrical Energy. A unit's heat rate is expressed in terms of British Thermal Units (Btu) per thousand watt-hour (kWh), or million Btu (MBtu) per million watt-hour (MWh).[2] The British

[2] Heat rates are traditionally expressed in Btu/kWh, while gas price are generally expressed in $/MBtu. Therefore when attempting to derive an electric energy price in $/MWh based on a heat rate and gas price, one must first divide the heat rate by 1,000 to convert if from Btu/kWh to MBtu/MWh. For example: if one wanted to determine the price per MWh of electrical output from

Thermal Unit is a standard measurement of heat energy. In the case of gas-fired Generating Units, the Btu or MBtu is used to measure the heat energy provided by the natural gas fuel source, or in other words, Btu or Mbtu is a measure of the gas input into the natural gas-fired Generator.

Q. PLEASE EXPLAIN HOW HEAT RATES AND HEAT RATE "CURVES" ARE DETERMINED.

A. The first step in determining the heat rate of a gas-fired Generating Unit under any given set of operating conditions is to determine the gross gas consumption (measured in Btu or MBtu) required to produce a certain amount of net power output (measured in kWh or MWh). Gross input refers to the total quantity of gas input into the boiler or combustion turbine portion of the generator plant. The net power output refers to the amount of electrical power output available to the electric utility system and is net of auxiliary power requirements necessary to operate the Generating Unit. These results are then typically converted into average heat rates by dividing gross gas consumption by the net amount of electricity produced. For example, if a unit is operated at a level that produces 10,000 kW for one hour (i.e. 10 MWh) and consumes 100,000,000 Btu of gas, the unit's average heat rate at an operating level of 10 MW is 10,000 Btu/kWh (or 10 MBtu/MWh).

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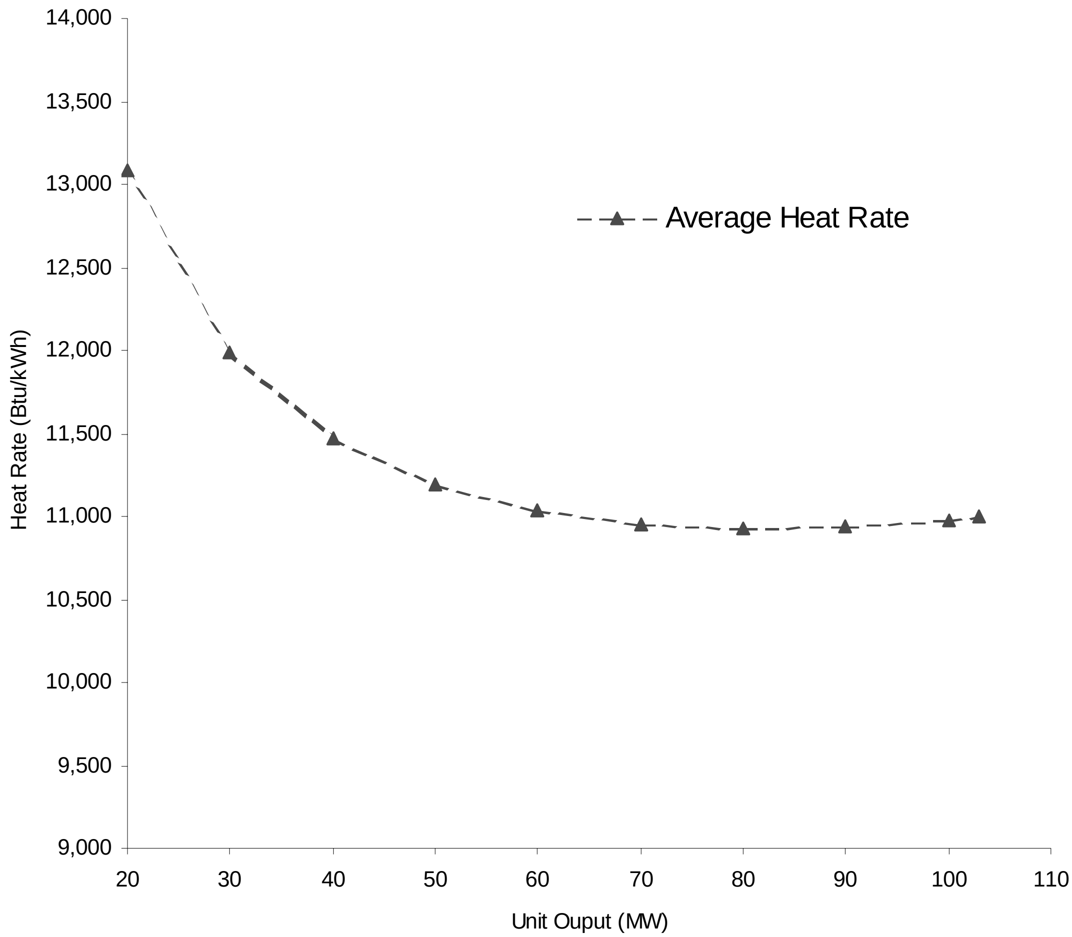
a unit when the incremental heat rate for that unit is 10,000 Btu/kWh and the gas price is 2.00 $/MBtu, the calculation would be: (10,000 Btu/kWh / 1000) x 2.00 $/MBtu = $20 /MWh.

The efficiency of a gas-fired Generating Unit typically varies significantly at different operating levels, just as the gas mileage of a car varies depending on the speed the car is traveling. Because of this variability, heat rates are typically calculated for a number of different operating levels, ranging from the unit's minimum operating level to its maximum level. Because the efficiency of gas units can also vary significantly depending on ambient temperatures and humidity, heat rates are often measured under different climatic conditions.[3]

Figure 1 depicts how the average heat rate of a gas unit can vary at 10 different operating levels, ranging from the unit's minimum operating level of 20 MW to its maximum operating level of 110 MW.

[3] For purposes of its heat rate calculations, the ISO used only the summer heat rates for those few units that submitted multiple sets of heat rates accounting for seasonal variations. To the extent that the use of different seasonal heat rates (i.e., "winter" heat rates) could have affected the marginal price calculated during an interval, the result would have been a lower marginal price. Thus, the ISO's use of only summer heat rates may have, if anything, resulted in some conservatively high mitigated prices.

Figure 1: Average Heat Rate Curve



As shown in Figure 1, the unit's average heat rate declines from 13,080 to 10,927 Btu/kWh as output increases from 20 MW up to 80 MW. However, at levels above 80 MW, the unit's average heat rate increases slightly from 10,927 to 10,995 Btu/kWh. The dashed lines connecting the average heat rates at the 10 operating levels depicted in Figure 1 represent the assumption that the unit's average heat rate at other operating levels between each pair of these 10 points is linear, allowing the unit's average heat rate at these other operating levels to be determined through simple linear interpolation between the 10 operating levels at which the heat rate was actually measured. When "connected" in this manner through linear interpolation, the line representing the unit's average heat rates at different operating levels is commonly referred to as the average heat rate curve.

Q. WHAT IS AN "INCREMENTAL HEAT RATE", AND HOW IS IT DERIVED FROM A UNIT'S AVERAGE HEAT RATE CURVE?

The incremental heat rate of a unit represents the incremental gas consumption for each additional unit of electrical output as the operating level of the unit is increased from one level to another. Incremental heat rates are directly calculated from an average heat rate curve, such as the one depicted in Figure 1. For example, the incremental heat rate of the unit displayed in Figure 1, as output is increased from 20 MW to 30 MW, can be calculated as follows:

1) First, the total gas consumption of the unit at an operating level of 20 MW (for one hour) is calculated as:

   (20 MWh x 1000 kWh/MWh) x 13,080 Btu/kWh = 261,600,000 Btu

2) Second, the total gas consumption of the unit at an operating level of 30 MW for the same duration is calculated as:

   (30 MWh x 1000 kWh/MWh) x 11,992 Btu/kWh = 359,760,000 Btu

3) Third, the increase in total gas consumption required for the unit to produce an additional 10 MWh by operating at a level of 30 MW compared to 20 MW is calculated:

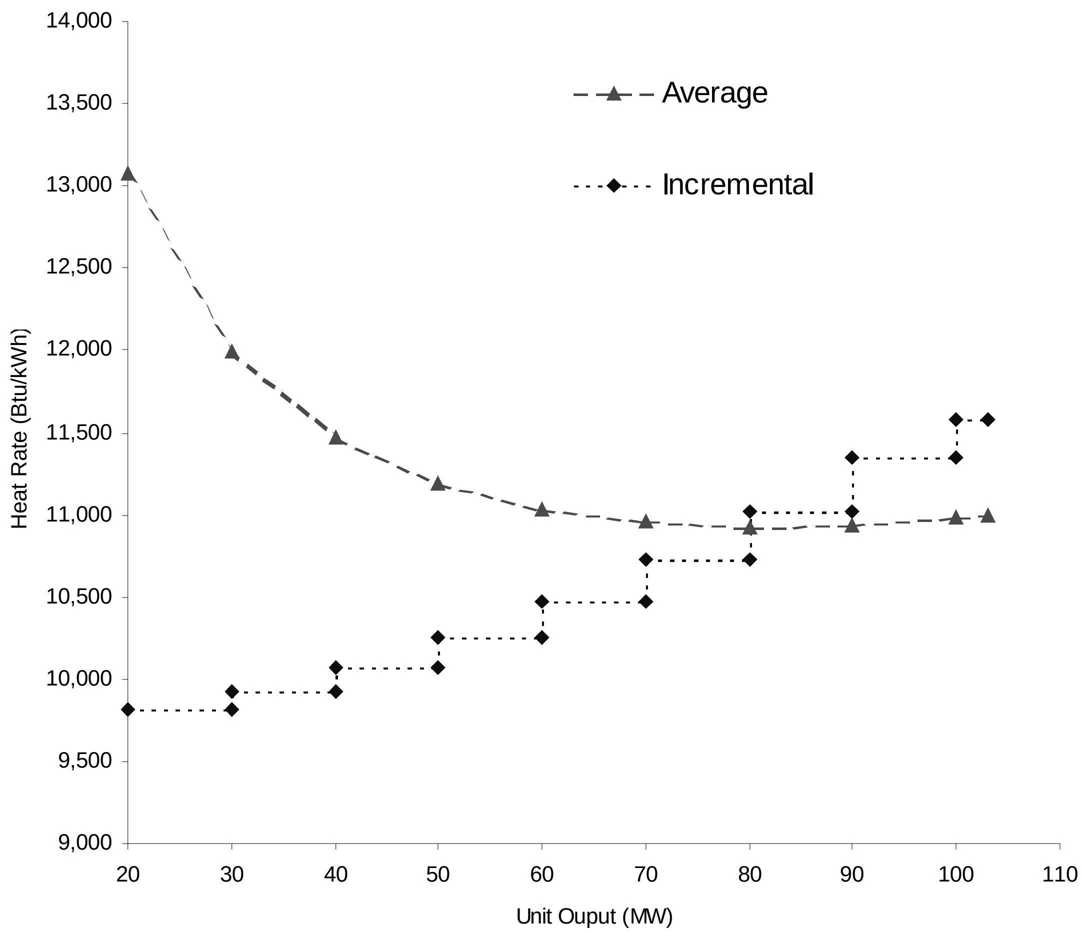
359,760,000 Btu – 261,600,000 Btu = 98,160,000 Btu

4) Finally, the total additional gas consumption of the unit for each additional MWh produced by operating at a level of 30 MW compared to 20 MW (i.e., the “incremental heat rate” for that operating range) is calculated:

98,160,000 Btu / (10 MWh x 1000 kWh / 1 MWh) = 9,816 Btu/kWh

Figure 2 depicts the results of this calculation for each operating level of this unit.

Figure 2: Average and Incremental Heat Rate Curves



Since incremental heat rates represent gas consumption per unit of output as output is increased (or decreased) from one operating point to another and the average heat rates between operating points are expressed as linear between each pair of the measured operating points, incremental heat rates are typically represented as linear step functions, as shown in Figure 2. Also, it should be noted that the number of "segments" in a linear step function representing incremental heat rates is always one less than the number of pairs of operating levels and average heat rates used in calculating the incremental heat rates. For example, a step function with 10 incremental heat rates is derived from a set of 11 measured average heat rate points. If only 10 measured heat rate points are available, a step function with 9 incremental heat rates can be generated. The nine incremental heat rates derived from the average heat rate curve depicted in Figures 1 and 2, are provided in Table 1 below:

Table 1: Average and Incremental Heat Rates

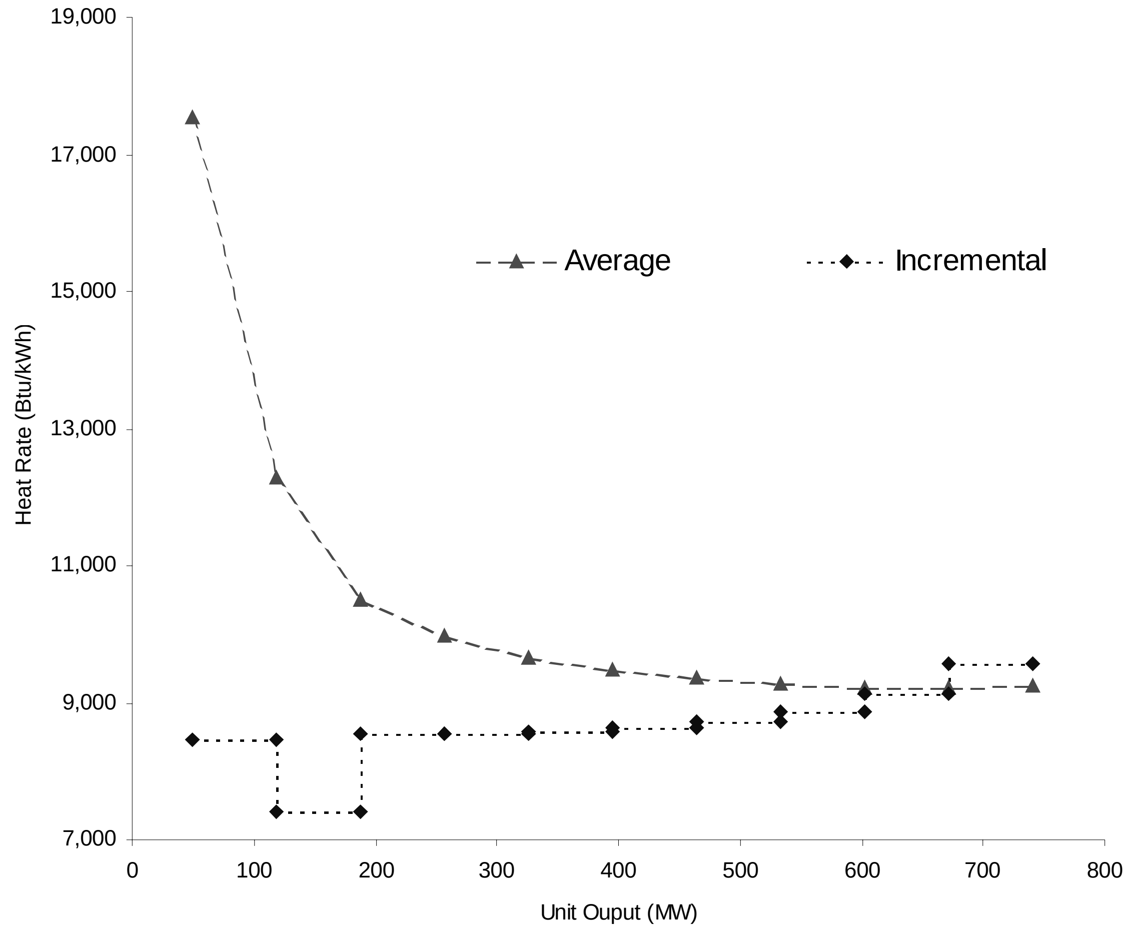
Segment	Point (MW)	Average Heat Rate (Btu/kWh)	Incremental Heat Rate (Btu/kWh)*
1	20	13,080	9,816
2	30	11,992	9,923
3	40	11,474	10,069
4	50	11,193	10,251
5	60	11,036	10,470
6	70	10,955	10,725
7	80	10,927	11,017
8	90	10,937	11,345
9	100	10,977	11,576
10	103	10,995	

* Incremental heat rate for increase in output for segment starting from the operating point on the same line of table (see column 2) to the operating point on the next line.

Q. DO INCREMENTAL HEAT RATES ALWAYS INCREASE AS THE OPERATING LEVEL OF A UNIT INCREASES?

A. No. Although the example provided in Figure 2 is representative of many gas-fired units, incremental heat rates may not always increase from one operating level to another. For example, Figure 3 shows the average and incremental heat rates for another gas-fired Generating Unit in the ISO Control Area. In this example, the incremental heat rate of the unit is constant as output increases from 50 MW up to 119 MW. However, as output increases from 119 MW to 188 MW, the unit's incremental heat rate decreases. As output is increased over 188 MW, the incremental heat rate then increases slightly as output is increased.

Figure 3: Decreasing Incremental Heat Rate Curve



II. KEY PROVISIONS OF THE COMMISSION'S MARKET MITIGATION ORDERS RELATING TO THE CALCULATION OF HEAT RATES AND GAS PROXY COSTS

A. HEAT RATES

Q. PLEASE DESCRIBE THE COMMISSION'S DETERMINATIONS WITH RESPECT TO HEAT RATE CALCULATIONS AS SET FORTH IN THE JULY 25 ORDER.

A. In the July 25 Order, for purposes of calculating refund liability in the ISO and California Power Exchange ("PX") spot markets, the Commission adopted essentially the mitigation methodology espoused in the June 19 Order, including the procedures for calculating heat rates specified in that Order. Although the Commission, in the July 25 Order, did require some modifications to the mitigation methodology set forth in the June 19 Order, the Commission did not alter the procedures for determining heat rates that were adopted in the June 19 Order, which were, in turn, based on the Commission's initial conclusions with respect to heat rate calculations contained in the April 26 Order.

Q. PLEASE DESCRIBE THE COMMISSION'S DETERMINATIONS WITH RESPECT TO HEAT RATE CALCULATIONS AS SET FORTH IN THE APRIL 26 ORDER.

A. In its April 26 Order, the Commission required operators of all gas-fired Generating Units in California to submit to the ISO heat rate data for each Generating Unit. The Commission explained that "[t]hese heat rates must reflect operational heat rates that do not include start-up and minimum load fuel costs . . . ." 95 FERC at 61,359.[4] The Commission explained that the ISO would use these heat rates to "calculate a marginal cost for each generator." *Id.*

Q. WHAT DETERMINATIONS DID THE COMMISSION MAKE WITH RESPECT TO HEAT RATE CALCULATIONS IN ITS JUNE 19 ORDER?

A. In the June 19 Order, the Commission addressed the ISO's proposal to collect average heat rate data from Generators based on eleven different operating points, with the first and last operating points representing a Generating Unit's minimum and maximum operating points. Noting that this methodology would allow the ISO to "approximate the actual incremental cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range," the Commission concluded that the ISO's proposal was reasonable. 95 FERC at 62,563. The Commission also stated that because the ISO would have the approximate heat rate curves for each unit, the ISO would be required to calculate the proxy Market Clearing Price ("MCP") based on the "approximate point on the heat rate curve at which the last unit is dispatched." *Id.*

[4] Start-up costs are the fuel costs associated with bringing a Generating Unit from a cold start to the point where the unit is ready and prepared to produce electrical Energy. Minimum load fuel cost is the gross fuel input required to produce electrical output at the minimum operating level of the unit. The minimum operating level of a unit is the lowest level of net output that can be delivered to the electrical system. As explained below, although minimum load fuel costs (but not start-up costs) are naturally incorporated into a unit's average heat rate curve, minimum load fuel

Q. WHAT DETERMINATIONS DID THE CHIEF JUDGE MAKE WITH RESPECT TO HEAT RATE CALCULATIONS IN HIS JULY 12 REPORT AND RECOMMENDATION TO THE COMMISSION?

A. The Chief Judge, 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"), recommended that the mitigation methodology set forth in the June 19 Order be adopted by the Commission for purposes of calculating refund liability for spot transactions made in the ISO and PX markets during the refund period (as noted earlier, October 2, 2000 through June 20, 2001). The Chief Judge explained that the ISO already had the "actual heat rate[s] for every hour of the last unit dispatched in the CAISO's real-time imbalance energy market," and that these actual heat rates, "rather than hypothetical heat rates . . . provide the first step in calculating the cost of the marginal unit." *Id.* at 65,040.

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costs are not represented in the incremental heat rate curves that the ISO derived from the average heat rate curves.

B. <u>GAS PROXY COSTS</u>

Q. PLEASE SUMMARIZE THE COMMISSION'S DETERMINATIONS IN THE JULY 25 ORDER WITH RESPECT TO THE METHOD FOR CALCULATING GAS PROXY COSTS FOR PURPOSES OF CALCULATING MITIGATED PRICES FOR TRANSACTIONS OCCURRING IN THE ISO AND PX MARKETS DURING THE REFUND PERIOD.

A. The Commission, in the July 25 Order, adopted the gas proxy cost calculation methodology recommended by the Chief Judge in his July 12 Report and Recommendation, with one minor modification. The Chief Judge's recommendation was based on the gas proxy cost methodology originally established by the Commission in the April 26 Order, as subsequently modified in the June 19 Order.

Q. LET'S SEE IF WE CAN UNDERSTAND THE COMMISSION'S POSITION IN THE JULY 25 ORDER BY REVIEWING THE BUILDING BLOCKS THAT WENT INTO THAT POSITION FROM THE APRIL 26 ORDER THROUGH THE CHIEF JUDGE'S RECOMMENDATION. FIRST, PLEASE DESCRIBE THE COMMISSION'S TREATMENT OF GAS PROXY COSTS IN THE APRIL 26 ORDER.

A. In its April 26 Order, the Commission instructed the ISO to calculate marginal costs for each gas-fired Generating Unit in California based on the heat rates submitted by the operators of those units and using a proxy for the gas costs incurred by those units. The Commission explained that this gas proxy cost would "use an average of the daily prices published in Gas Daily for all California delivery points." 95 FERC at 61,359. The ISO was required to publish by 8:00 a.m. each day the gas costs "to be used the next day in any hour where an emergency is declared." *Id.* These costs were to be based on the prior day's *Gas Daily* price data.

Q. DID THE COMMISSION MAKE ANY MODIFICATIONS TO ITS METHODOLOGY FOR CALCULATING GAS COSTS IN ITS SUBSQEUENT MARKET MITIGATION ORDERS?

A. Yes. In the Commission's May 25, 2001 "Order Providing Preliminary Clarification and Guidance on Implementation of Mitigation and Monitoring Plan for the California Wholesale Electric Markets", 95 FERC ¶ 61,275 (2001), the Commission rejected the ISO's proposal to develop a proxy price for natural gas based on only three California delivery points. The Commission clarified that the April 26 Order required the ISO to calculate the gas proxy price using the published daily prices for all California delivery points published in *Gas Daily*, but noted that it would "consider whether any changes should be made to the California delivery points during rehearing of the April 26 Order." *Id.* at 61,971.

In the June 19 Order, which was the order on rehearing from the April 26 Order, the Commission declared that it would continue to use a proxy cost for gas in determining fuel costs for Generators subject to market mitigation, and rejected the use of actual gas costs, reasoning that actual gas costs "would not provide price transparency, and would be administratively infeasible because it would require a constant reevaluation of every generator's bids." 95 FERC at 62,560. However, the Commission concluded that it would modify the spot gas prices to be used in the marginal cost formula consistent with the ISO's proposal to average the mid-point of the monthly bid-week prices reported by *Gas Daily* for three spot market prices reported for California: Malin, Southern California Gas large packages, and PG&E Citygate. The Commission explained that this "represents a reasonable proxy for the marginal cost that generators will incur, since they can pre-buy their gas requirements for the month at this price." *Id.* at 62,561.

Q. DID THE CHIEF JUDGE RECOMMEND THAT ANY ADJUSTMENTS BE MADE TO THE COMMISSION'S GAS PROXY COST METHODOLOGY AS SET FORTH IN THE JUNE 19 ORDER, FOR PURPOSES OF CALCULATING MITIGATED PRICES TO BE USED IN DETERMINING SUPPLIERS' REFUND LIABILITY FOR TRANSACTIONS OCCURRING IN THE ISO AND PX MARKETS DURING THE REFUND PERIOD?

A. Yes. Explaining that spot energy sales in the ISO's markets are made with spot gas purchases, the Chief Judge recommended, in his July 12 Report and Recommendation, that gas costs associated with the marginal unit should be based upon a daily spot gas price. Additionally, because spot gas prices "vary significantly between southern and northern California," the Chief Judge found that "[s]imply averaging gas prices in the north with gas prices in the south" would not "adequately capture the significant effect of gas prices on the cost of electricity during the refund period." 96 FERC at 65,040. Therefore, the Chief Judge recommended that for situations in which the marginal unit is located in the ISO's North of Path 15 Zone ("NP15"), the ISO should use the average of the daily spot gas price for the PG&E Citygate and Malin delivery points as the gas proxy cost in its mitigated price calculation. For situations in which the marginal unit is located in the ISO's South of Path 15 Zone ("SP15"), the Chief Judge suggested that the ISO should use the daily spot gas price for Southern California Gas large packages as the gas proxy cost. Additionally, the Chief Judge stated that these daily spot gas prices should be the "midpoint" index price as published in Financial Times Energy's *Gas Daily* for the designated delivery points. For days that *Gas Daily* was not published, the Chief Judge recommended that the ISO be required to use the "last published gas prices" in calculating the mitigated price. *Id.*

Q. DID THE COMMISSION, IN ITS JULY 25 ORDER, ADOPT THE CHIEF JUDGE'S RECOMMENDATIONS WITH RESPECT TO CALCULATING THE GAS PROXY PRICE FOR PURPOSES OF REFUND DETERMINATIONS?

A. Yes, with one modification. The Commission accepted the Chief Judge's recommendation that the ISO calculate the mitigated price using either the average daily spot gas price for PG&E Citygate and Malin, if the marginal unit is located in the NP15 Zone, or the daily spot gas price for Southern California Gas large packages, if the marginal unit is located in the SP15 Zone. The Commission also clarified that the average daily spot gas prices "are to be used to calculate a single clearing price." 96 FERC at 61,518. Finally, although the Commission adopted the Chief Judge's recommendation to use daily spot gas prices and the three delivery points, the Commission stated that it would require the ISO to calculate the gas price inputs based on a simple average of the daily spot prices reported by *Gas Daily* as well as National Gas Intelligence's *Daily Gas Price Index* and Inside FERC's *Gas Market Report*. The Commission explained that it was making this modification because "the Commission has in the past used a composite of published market prices" and "using multiple sources addresses a number of concerns including reducing the effect of errors that might occur in gathering and reporting spot price data." *Id.* However, the Commission did note that *Daily Gas Price Index* and *Gas Market Report* did not contain a listing for Southern California Gas large packages during the refund period.

III. CALCULATION OF INCREMENTAL HEAT RATES

Q. PLEASE SUMMARIZE THE MANNER IN WHICH THE ISO CALCULATED HEAT RATES FOR GENERATORS PURSUANT TO THE COMMISSION'S MARKET MITIGATION ORDERS.

A. The basic methodology used by the ISO to determine heat rates used to implement the Commission's orders consisted of three steps:

1) First, the ISO collected data on average heat rates of gas-fired units at different operating levels within the ISO system from Generators required to submit this information pursuant to the April 26 Order.

2) Second, the average heat rates were converted to average heat rate curves, and from those curves were derived incremental heat rate curves, which represent the marginal increase in gas consumption for each additional unit of output from a Generating Unit at different operating levels.

3) Finally, incremental heat rate curves, representing the incremental heat rate of a unit at different operating levels, were adjusted, if necessary, to ensure that the heat rates derived from these curves did not decrease as the operating level of the unit increased. As explained below, this adjustment was necessary to ensure that cost-based bids generated from incremental heat rate curves, representing Energy from individual Generating Units at progressively higher operating levels, could be dispatched in economic merit order (i.e., in increasing order of calculated, cost-based bid price) through the ISO Balancing Energy and Ex Post Pricing ("BEEP") Software.

Q. HOW DID THE ISO COLLECT HEAT RATE DATA FROM GENERATORS REQUIRED TO SUBMIT THIS DATA PURSUANT TO THE APRIL 26 ORDER?

A. Pursuant to the Commission's requirement in the April 26 Order that the ISO collect heat rates of all gas-fired Generating Units in California, the ISO issued two market notices, one on April 27, 2001 and the other on April 30, 2001, requesting that Generating Unit owners provide heat rate data in a format consistent with a template developed by the ISO. These notices, including the template, are attached as Exhibit No. ISO-6. The template developed by the ISO provided for the submission of heat rate data (in Btu/kWh) for up to eleven different operating points in MWs, with the first and last operating points representing a unit's minimum and maximum operating levels, respectively. The ISO explained that although an owner did not necessarily have to supply heat rate data for all eleven operating points, data for a minimum of two operating levels should be provided. Additionally, in its April 30, 2001 notice, the ISO clarified that the heat rates provided by Generating Unit owners should be stated as the *average* heat rate at each operating point rather than as the *incremental* heat rate.

Q. WHY DID THE ISO REQUEST HEAT RATE DATA FROM GENERATORS FOR ELEVEN OPERATING POINTS?

A. Although a heat rate curve may be developed based on any number of operating points, the ISO chose to collect heat rate data for eleven operating points for several reasons. First, calculating ten incremental heat rates based on heat rates curves with heat rates for up to 11 operating points was directly compatible with the existing database structures of the ISO, and thereby allowed the ISO to implement the April 26 and June 19 Orders as expeditiously as possible, while minimizing the risk of unforeseen operational problems that may sometimes result from software changes. Under the mitigation plan adopted by the Commission in the April 26 and June 19 Orders, heat rate submitted by Generators are used (along with assumptions about gas costs and other variable operating costs) to generate "proxy bids" that are substituted for bids submitted by Generators in the ISO's BEEP Software system used to dispatch real time Energy Bids when cost-based mitigation of bids is in effect. As discussed above, a heat rate curve with 11 pairs of bid prices and quantities can be converted into 10 linear segments. By limiting heat rate curves to a maximum of 11 operating points -- representing 10 segments -- the ISO ensured that the number of proxy bid segments generated directly from heat rate data would not exceed the maximum number of real time Energy Bid segments allowed by the ISO's BEEP Software for any individual resource Schedule.

Also, using heat rate data on eleven operating points allows for a highly accurate representation of how the efficiency (or average heat rate) of Generating Units varies at different operating points. While there is no industry standard on the number of data points required to determine a sufficiently accurate heat rate curve, commercially available heat rate data from entities such as Henwood Energy Services provides for 5 operating points while other models such as the Environmental Defense's Electric System and Planning Software (used historically by California IOU's in state regulatory proceedings) provide for up to 10 operating points.

Finally, it is important to note that the Commission, in the June 19 Order, explicitly approved the ISO's method of collecting heat rate data based on eleven operating points. Therein, the Commission stated that "the ISO's proposal to include the minimum and maximum operating levels for each unit and nine points in between is reasonable." 95 FERC at 62,563.

Q. WHY IS THE ISO'S BEEP SOFTWARE LIMITED TO TEN ENERGY BID SEGMENTS FOR EACH INDIVIDUAL RESOURCE SCHEDULE?

A. When the California electric market was designed, prior to the operational startup of the ISO in March 1998, it was determined through a stakeholder process that the maximum number of segments necessary to sufficiently express a bid curve into the ISO's markets was ten. As explained above, in order to express a curve with ten segments, it is necessary to provide 11 pairs of bid prices and quantities. As a result, the database structures developed by the ISO to store and process submitted bids are designed to accommodate up to 11 combinations of prices and quantity (or "price quantity points"). Changing this limitation at this time would have required substantial changes to the ISO's operational software and database structure, potentially delaying the implementation of the Commission's market mitigation measures.

Q. WHY DID THE ISO REQUEST AVERAGE RATHER THAN INCREMENTAL HEAT RATE DATA FROM GENERATORS?

A. The ISO requested average heat rates rather than incremental heat rates for several reasons: (1) it is standard practice in the industry to test a unit's efficiency using average heat rates; (2) average heat rates are directly derived from a unit's input/output heat curve, as measured in regular unit testing; and (3) because different assumptions can be made when calculating incremental heat rates from average heat rates, the ISO wanted to ensure that the method used to convert average heat rates into incremental heat rates was performed consistently.

Q. HOW DID THE ISO CONVERT THE AVERAGE HEAT RATE DATA SUBMITTED BY GENERATORS INTO AN INCREMENTAL HEAT RATE CURVE FOR EACH GENERATOR?

A. The ISO derived the incremental heat rate curves for each relevant gas-fired

Generator in a manner consistent with the discussion above explaining the procedure for determining incremental heat curves based on average heat rate data.

Q. DID THE ISO MAKE ANY ADJUSTMENTS TO THE INCREMENTAL HEAT RATES THAT IT CALCULATED?

A. Yes. As explained above, incremental heat rates may not always increase from one operating level to another. Thus, it was the case with some of the Generating Units for which the ISO calculated incremental heat rates that, for certain segments, the incremental heat rate of the unit decreased as the output of the unit increased. The ISO adjusted these incremental heat rate curves so that a unit's incremental heat rate never decreases (i.e., it always increases or remains constant) as the operating level of the unit increases. A heat rate curve that possesses this characteristic is described as “monotonically non-decreasing.”

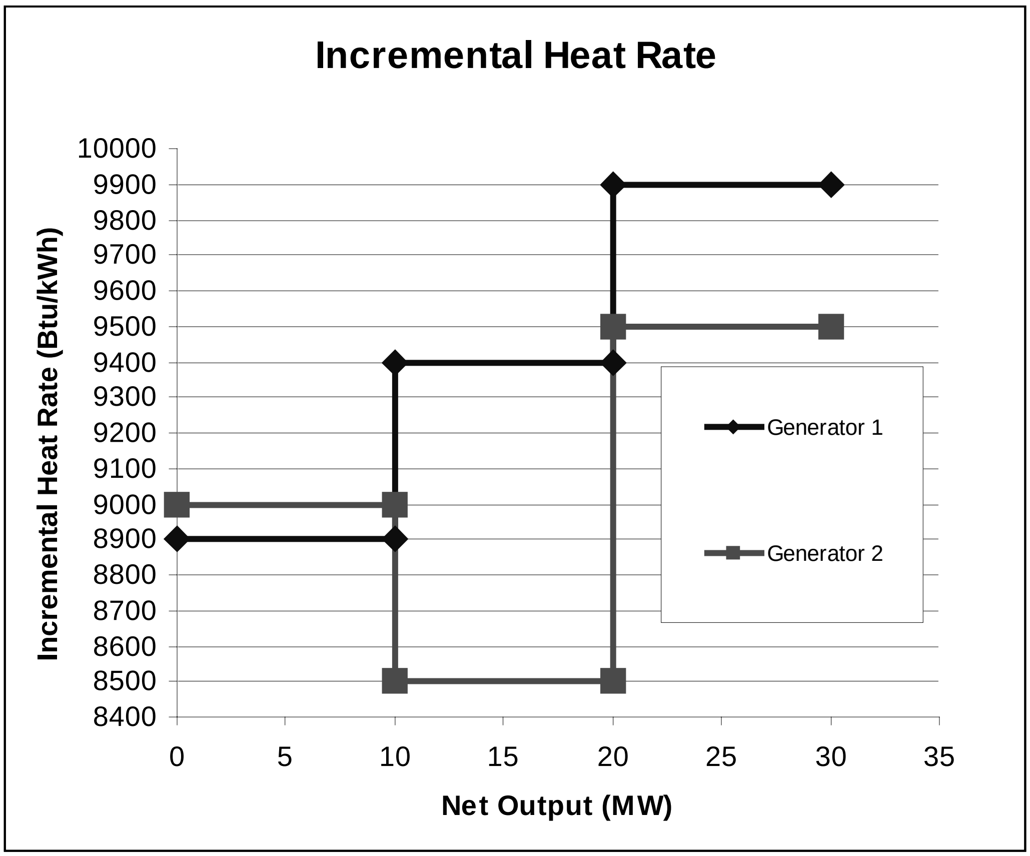
Q. WHY DID THE ISO ADJUST INCREMENTAL HEAT RATE CURVES IN ORDER TO ENSURE THAT THESE CURVES WERE MONOTONICALLY NON-DECREASING?

A. From the perspective of the ISO’s market design and software, it is necessary that a unit’s incremental heat rate curve be monotonically non-decreasing. If a unit’s heat rate is not monotonically non-decreasing, it is impossible for the ISO to derive cost-based “proxy bids” for real time Energy based directly on incremental heat rates. Like many electric utility dispatch algorithms, the ISO’s merit order dispatch algorithm is based on certain fundamental rules and economic concepts. One of these rules is that, assuming no other physical constraints, generation resources will be dispatched in such a way that output is increased (not decreased) as load or demand increases. To ensure that this fundamental concept is enforced, it is necessary that each resource dispatched to meet Imbalance Energy requirements have an incremental heat rate curve (which corresponds to an incremental cost curve) that is monotonically non-decreasing.

Q. PLEASE DESCRIBE WHAT WOULD RESULT IF THE ISO WERE TO USE INCREMENTAL HEAT RATES THAT ARE NOT MONOTONICALLY NON-DECREASING.

A. To understand what could happen if the incremental heat rate curves used for dispatch were not monotonically increasing, assume that there are two Generating Units (referred to in this example as "Generators"), as illustrated in Example 1 below. Generator 1 has a monotonically non-decreasing incremental heat rate curve with three segments. Generator 2 also has a three segment incremental heat rate curve, but the curve is not monotonically non-decreasing. When demand is between 0 and 10 MW the optimum solution would be to dispatch Generator 1 up 10 MW, since its incremental heat rate is 8,900 Btu/kWh, which is less than the incremental heat rate of Generator 2 at an output level up to 10 MW. In this situation, the marginal heat rate is therefore 8,900 Btu/kWh. However, when load increases above 10 MW up to 20 MW the optimum dispatch would result in a reduction of output for Generator 1 from 10 MW to 0 MW, and an increase in output for Generator 2 from 0 MW to 20 MW. This result violates the first rule of the merit order dispatch algorithm: that in order to meet increasing demand, generation from a given unit should remain constant or be increased, but not decreased. Furthermore, note that the marginal heat rate is reduced from 8,900 Btu/kWh to 8,500 Btu/kWh when demand increases from 10 MW to 20 MW. This violates the economic principle that the cost of energy should increase as demand increases.

Example 1:
Dispatch and Marginal Pricing Problems when Incremental Heat Rates Are Not Monotonically Non-Decreasing

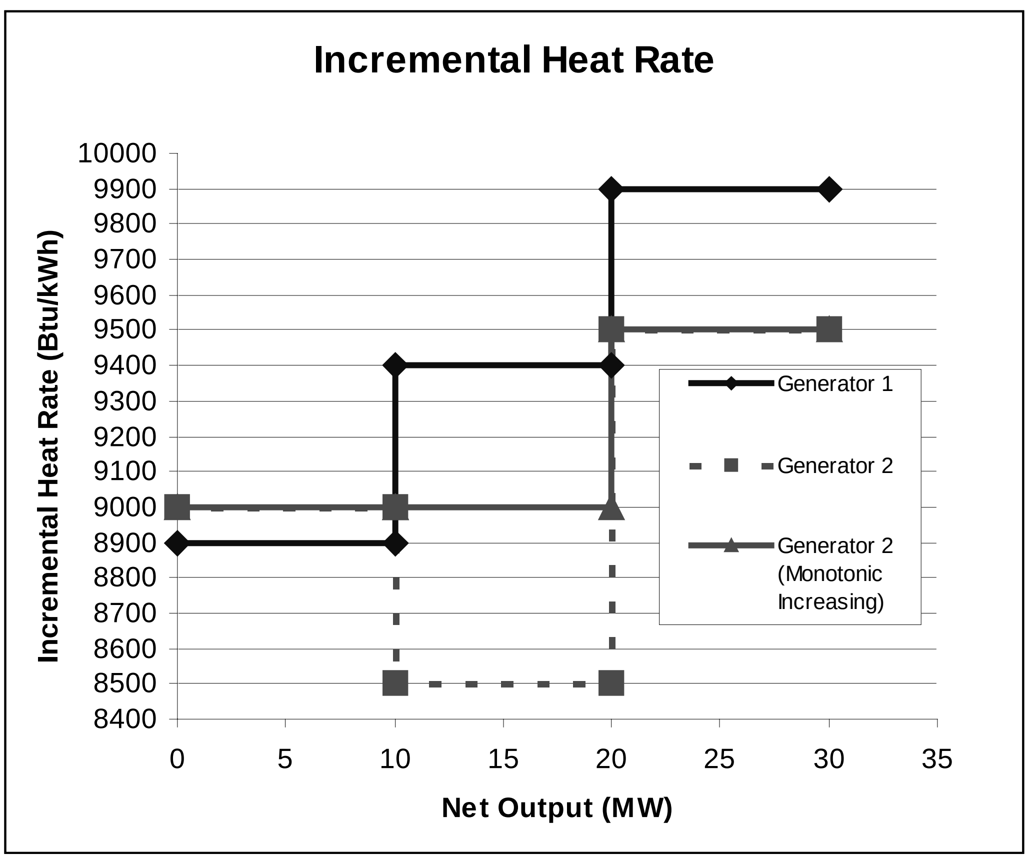


Demand (Load) (MW)	Generator 1 Output (MW)	Generator 1 IHR (Btu/kWh)	Generator 2 Output (Mw)	Generator 2 IHR (Btu/kWh)	Marginal Heat-Rate (Btu/kWh)
10	10	8,900	0	N/A	8,900
20	**0**	N/A	20	8,500	**8,500**
30	10	9,000	20	8,500	9,000
40	20	9,400	20	8,500	9,400
50	20	9,400	30	9,500	9,500
60	30	9,900	30	9,500	9,900

Q. HOW DID THE ISO ADJUST INCREMENTAL HEAT RATE CURVES TO ENSURE THAT THEY WERE MONOTONICALLY NON-DECREASING?

A. To resolve the dispatch and marginal pricing issues that are encountered when incremental heat rate curves are not monotonically non-decreasing, the ISO, as noted above, adjusted the incremental heat rate curves in those cases where the incremental heat rate of a unit decreased as the output of the unit increased. When the ISO determined that an incremental cost curve segment was less than the previous cost segment, that cost segment was set equal to the cost of the previous cost segment. For instance, in Example 1 above, Generator 2's incremental heat rate curve between the 10 and 20 MWh output levels would be adjusted up to 9,000 Btu/kWh (the same heat rate as the previous segment). With this adjustment made, Generator 2's incremental heat rate curve becomes monotonically non-decreasing. The consequences of this adjustment to the dispatch and marginal pricing scenario discussed in the previous answer is illustrated in Example 2 below. As system demand increases from 10 MW to 20 MW, Generator 1 is not dispatched down as was the case in Example 1. Rather the output of Generator 1 is held constant at 10 MW while Generator Unit 2 is dispatched up to 10 MW meet the increase in demand. Additionally, the marginal heat rate increases from 8,900 Btu/kWh to 9,000 Btu/kWh as the demand increases from 10 MW to 20 MW, a result that is consistent with the economic principle that the cost of energy increase as demand increases.

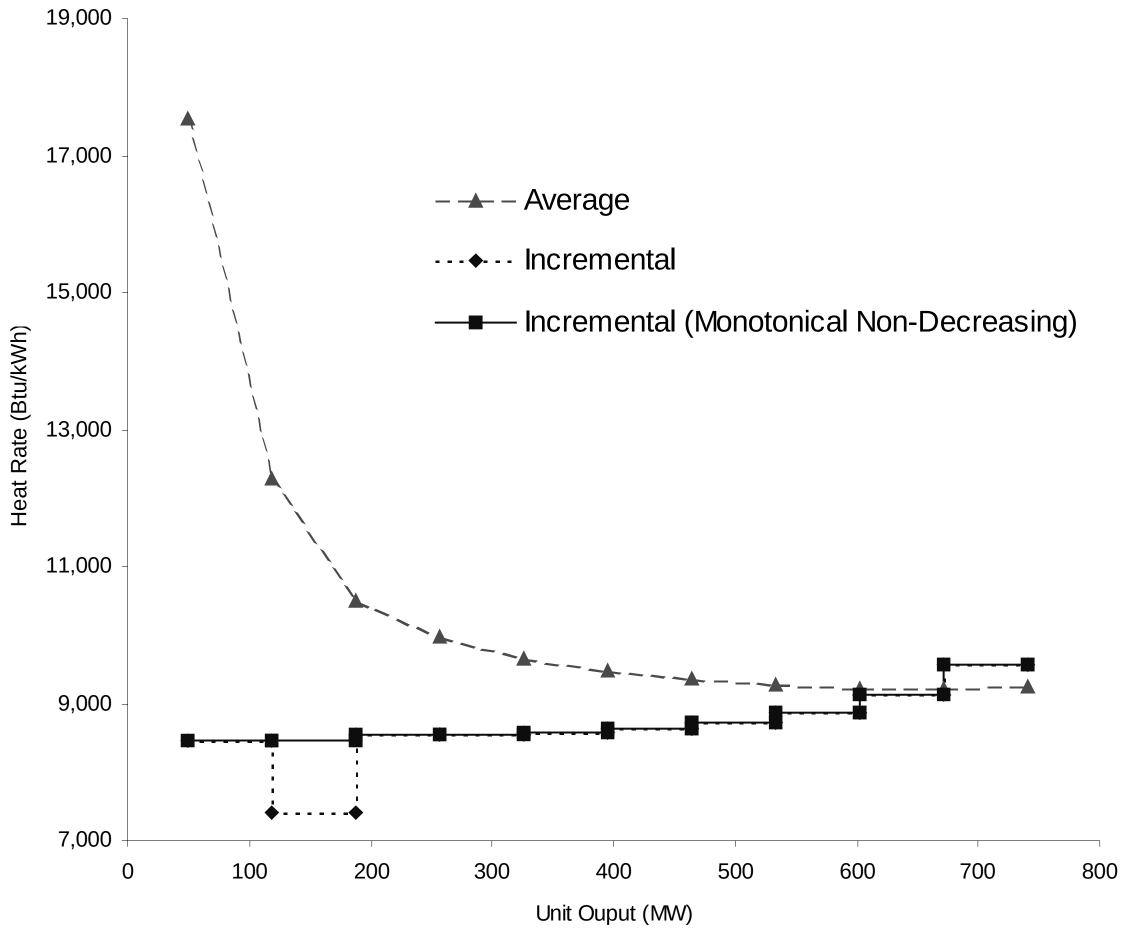
Example 2:
Dispatch and Marginal Pricing Problems Resolved with Monotonically Non-Decreasing Curves



Demand (Load) (MW)	Generator 1 Output (MW)	Generator 1 IHR (Btu/kWh)	Generator 2 Output (Mw)	Generator 2 IHR (Btu/kWh)	Marginal Heat-Rate (Btu/kWh)
10	10	8,900	0	N/A	8,900
20	**10**	8,900	10	9,000	**9,000**
30	10	9,000	20	8,500	9,000
40	20	9,400	20	8,500	9,400
50	20	9,400	30	9,500	9,500
60	30	9,900	30	9,500	9,900

An example of the ISO's adjustment of an actual incremental heat rate curve to ensure that it was monotonically non-decreasing is illustrated in Figure 4. Figure 4 illustrates the same unit as in Figure 3 with an adjustment to ensure the unit has a monotonic curve between 119 MW and 188 MW.

Figure 4: Incremental Heat Rate Curve Adjusted to Ensure Monotonicity



Q. WHY DID THE ISO CHOOSE TO USE INCREMENTAL RATHER THAN AVERAGE HEAT RATES IN ITS COMPUTATION OF THE MITIGATED PRICE?

A. The ISO used incremental, rather than average, heat rates to determine the mitigated price for the following reasons:

1) The ISO's use of incremental heat rates is consistent with the ISO's compliance with the April 26 and June 19 Orders that preceded the July 25 Order. The April 26 Order, among other things, provided a

method for price mitigation in the Real Time Market during reserve deficiencies; as explained above, this price mitigation methodology required the ISO to use heat rates to calculate the marginal cost for each Generator for purposes of determining the proxy bid that would set the MCP. On May 18, 2001, the ISO submitted a status report informing the Commission of the procedure it was following with respect to heat rates in order "to approximate the actual incremental cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range." 95 FERC at 62,563. In the June 19 Order, the Commission approved the ISO's approach, and noted that "because the ISO will have the approximate heat rate curve for each unit, the ISO is directed to calculate the proxy MCP based upon the approximate point on the heat rate curve at which the last unit is dispatched." *Id.* Consequently, the ISO has continued to apply an incremental methodology with regard to heat rates, and understands that the July 25 Order, by adopting the methodology that had been set forth in the June 19 Order, also requires an incremental methodology.

2) In the July 25 Order, the Commission required "that the ISO 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 . . . 96 FERC at 61,517. The

"marginal unit," in the economic sense of the term, means the incremental or extra unit. For example, the definition of "marginal" contained in the *MIT Dictionary of Modern Economics* provides that "[a] marginal unit is the extra unit of something, as with marginal cost, marginal utility etc." Moreover, that dictionary explains, in the definition of the term "margin," that "[i]n economics, 'at the margin' means at the point where the last unit is produced or consumed." Additionally, Paul A. Samuelson and William D. Nordhaus, in the glossary of terms of their textbook entitled *Economics*, define "marginal cost" as "[t]he extra cost (or the increase in total cost) required to produce 1 extra unit of output (or the reduction in total cost from producing 1 unit less)."

3) The MCP in a uniform-price auction (where all suppliers are paid the MCP), such as the ISO's Real Time Market, is determined by the cost of the next increment of demand. Therefore, the calculation of the mitigated price based on incremental, rather than average, heat rates is consistent with economic theory and actual auction and market clearing practices, because the calculation of the mitigated price is based on identifying the marginal unit (i.e., the unit needed to produce the last unit of Energy consumed).

4) As I explain in detail below, using incremental as opposed to average heat rates was necessary in order to exclude start-up and

minimum load fuel costs from the marginal price calculation, as was explicitly required by the Commission.

5) A price determination based on average heat rates would result in awkward and confusing results with perverse incentives. Using average heat rates would result in efficient units being loaded partially, high prices during off-peak system conditions, and low prices during peak system conditions. Example 3 and Table 2 illustrate the pricing problems inherent in using average heat rates. As the load increases from 10 MW to 50 MW the average heat rate at the level of output needed to meet load, and thus the “marginal” heat rate, decreases from 11,000 (Btu/kWh) to 9,900 (Btu/kWh), because Generator 1’s heat rate is consistently lower than Generator 2’s heat rate and Generator 1 can meet up to 50 MW of demand. Because Generator 2 must be used above 50 MW of load, the heat rate jumps up to 12,000 (Btu/kWh) when Generator 2 begins to generate at 10 MW to enable the two generators together to serve 60 MW of total load. As the load continues to increase from 60 MW to 100 MW the average heat rate at the level of output needed to meet that last increment of demand, i.e., the “marginal” heat rate, again decreases from 12,000 to 10,000 (Btu/kWh). Therefore, if average heat rates are used, the “marginal” heat rate will actually be decreasing during significant periods in which demand is increasing. This result violates one of the basic

economic tenants of generation dispatch discussed above, namely, that the price of energy should increase as demand increases.

Example 3: Pricing Problems When Using Average Heat Rates

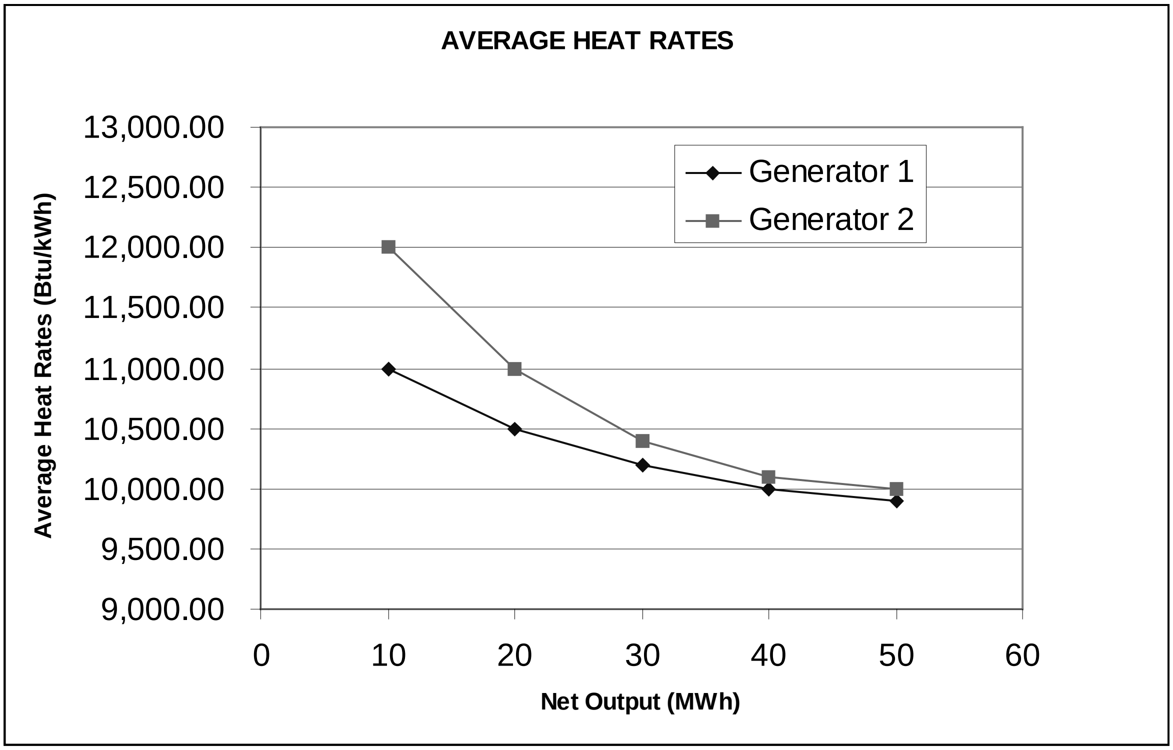


Table 2: Pricing Using Average Heat Rates

Demand / Load	Generator 1 Output (MW)	Generator 1 Average Heat Rate (Btu/kWh)	Generator 2 Output (MW)	Generator 2 Average Heat Rate (Btu/kWh)	Highest Average Heat Rate (Btu/kWh)
10	10.00	11000	0	N/A	11,000
20	20.00	10500	0	N/A	10,500
30	30.00	10200	0	N/A	10,200
40	40.00	10000	0	N/A	10,000
50	50.00	9900	0	N/A	9,900
60	50.00	9900	10	12,000	12,000
70	50.00	9900	20	11,000	11,000
80	50.00	9900	30	10,400	10,400
90	50.00	9900	40	10,100	10,100
100	50.00	9900	50	10,000	10,000

Q. DO THE INCREMENTAL HEAT RATE CURVES CALCULATED BY THE ISO EXCLUDE START-UP AND MINIMUM LOAD FUEL COSTS, AS REQUIRED BY THE COMMISSION?

A. Yes. Heat rate data is generally produced by measuring fuel input to produce a net output of electrical Energy, and start-up fuel costs are not typically included in these operational measurements. Therefore, the incremental heat rate curves that the ISO created using this data would not include start-up fuel costs. Minimum load fuel costs, however, are naturally incorporated into the average heat rate that is determined when a unit operates at minimum load. Nevertheless, because incremental heat rates are a measure of additional fuel input required to produce an additional quantity of electrical Energy, incremental heat rates by nature exclude minimum load fuel costs. Therefore, using incremental heat rate curves to determine marginal prices was necessary in order for the ISO to comply with the Commission's directive to exclude minimum load fuel costs.

Q. HOW HAS THE ISO DISPLAYED THE RESULTS OF ITS HEAT RATE CALCULATIONS?

A. The data collected by the ISO on the average heat rates as well as the incremental heat rates calculated using these average heat rates are contained in a spreadsheet attached as Exhibit No. ISO-7. This Exhibit contains the most recent information that the ISO has concerning Generating Unit heat rates, and includes several corrections to the heat rates used by the ISO in its initial calculation of the mitigated prices and refunds, which were distributed to participants in this proceeding on August 15, 2001. This updated heat rate information was used in calculating the mitigated prices discussed in the Direct Testimony of Dr. Eric Hildebrandt, submitted today. Additionally, the ISO has prepared graphical representations of the average heat rate curves and associated incremental heat rate curves for each of the units identified in the spreadsheet (except for those units for whom the ISO was provided heat rate data on only one operating level). These are attached as Exhibit No. ISO-8.

<u>IV. CALCULATION OF FUEL COSTS FOR THE MARGINAL UNIT</u>

Q. HOW DID THE ISO CALCULATE THE FUEL COSTS ASSOCIATED WITH THE MARGINAL UNIT IDENTIFIED FOR EACH INTERVAL?

A. The ISO calculated the fuel costs associated with the marginal unit for each 10-minute interval as identified in its mitigated price calculation by multiplying the incremental heat rate of the marginal unit by the daily spot market gas costs, determined in accordance with the Commission’s instructions in the July 25 Order.

Q. HOW DID THE ISO DETERMINE THE DAILY SPOT MARKET GAS COSTS THAT IT USED IN ITS FUEL COST CALCULATION?

A. Consistent with the July 25 Order, if a marginal unit identified in the ISO's mitigated price calculation is located in the northern zone (NP15), the ISO used the average daily spot gas price for Malin and PG&E Citygate delivery points in order to calculate fuel costs for that unit. The average daily spot gas prices for NP15 for intervals in hours that occurred on or after March 9, 2001 represent an average of the prices reported for these two delivery points by three indices: Financial Times Energy's *Gas Daily*, National Gas Intelligence's *Daily Gas Price Index*, and Inside FERC's *Gas Market Report*. For those intervals with a marginal unit located in NP15 that occurred prior to March 9, 2001, the ISO used the average of the daily spot gas prices as reported by the first two indices, because Inside FERC did not publish daily gas index prices for these points prior to that date.

If the marginal unit identified by the ISO in its mitigated price calculation was in the southern zones (either SP15 or ZP26[5]), the ISO usually used the Southern California large packages midpoint daily spot gas price, as reported in the Financial Times Energy's *Gas Daily*, to determine the unit's fuel costs. There were, however, two units that, although electrically located in congestion zone ZP26, were considered to be in the NP15 zone for purposes of calculating gas proxy prices: Morro Bay Power Plant and

[5] ZP26 is the congestion zone that is located electrically south of zone NP15 bounded by the Path 15 constraint but north of the zone SP15 bounded by Path 26.

Texaco North Midway. The price of gas utilized at these plants was assumed to be consistent with the NP15 zone because of their proximity to northern California gas supplies.

Q. HAS THE ISO PROVIDED THE GAS PROXY PRICES USED IN ITS FUEL COST CALCULATION?

A. Yes. The ISO was originally unable to provide the gas proxy prices used in its fuel cost calculations because *Gas Daily* considered its historical listing of daily spot prices to be proprietary information and those historical listings would be revealed whenever the marginal unit was in either SP15 or ZP26 (since *Gas Daily* was the only publication used in those instances). The ISO eventually was able to obtain authorization from *Gas Daily* to make this data available to participants in this proceeding who had signed the applicable non-disclosure agreement, and distributed the proxy gas prices to those participants on September 10, 2001. The gas proxy prices for each interval during the refund period are attached as Exhibit No. ISO-9.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.