UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant,	)		
v.	)	Docket Nos.	EL00-95-045
Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	)		
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)		EL00-98-042

PREPARED REBUTTAL TESTIMONY OF
DRS. CARL PECHMAN AND MILES BIDWELL
ON BEHALF OF
THE CALIFORNIA PARTIES

REBUTTAL TESTIMONY

I. INTRODUCTION AND SUMMARY

A. INTRODUCTION

Q. Who prepared this testimony?

A. This testimony was prepared by and under the supervision of Drs. Carl Pechman and Miles Bidwell.

Q. Dr. Pechman, please state your name and business address.

A. My name is Carl Pechman. My address is 180 7th Ave., Suite 105, Santa Cruz, California 95062.

Q. By whom are you employed and in what capacity?

A. I am President of Power Economics, Inc., a consulting firm specializing in the economics of electricity.

Q. Please describe briefly your educational and employment background.

A. I earned my B.S. degree in biology in 1976, my M.S. degree in Applied Econometrics and Quantitative Analysis in 1983, and my Ph.D. degree in Resource Economics in 1990. All of my degrees were earned at Cornell University in Ithaca, New York.

From 1979 through 1997, I held a series of positions of increasing responsibility at the New York Public Service Commission. When I left the Commission in 1997, I was Supervisor of Energy and Environmental Economics. In that role, I was responsible for the economic analysis of a wide variety of issues related to the costing, pricing and production of electricity. I played an active role in the creation of the New York Independent System Operator, and in evaluating alternative models of competition.

In 1997, I left the New York Public Service Commission and joined the economics consulting firm of LECG, as a Director. At LECG, I worked with a variety of clients on issues related to the transformation of the electric utility system to competitive markets.

I founded Power Economics, Inc., in November of 1999. More information about Power Economics can be found at www.powereconomics.com.

My curriculum vitae is included as Attachment A.

Q. Dr. Bidwell, please state your name and business address.

A. My name is Miles Bidwell. My address is PO Box 7879, Greenwich, CT 06836-7879.

Q. In what capacity are you presenting testimony?

A. I am a Principal of Power Economics, Inc.

Q. Please describe briefly your educational and employment background.

A. I hold B.A., M.A. and Ph.D. degrees in Economics from Columbia University, where I specialized in applied microeconomic theory and econometrics.

Until 1996, I was a Vice President of National Economic Research Associates, Inc. (NERA). Before joining NERA, I served as Chief of Regulatory Research for the New York State Department of Public Service. At the same time, I designed and directed the graduate Program in Regulatory Economics at the State University of New York at Albany, where I was an adjunct professor. For the last fifteen years, I have been conducting research and advising clients on issues related to the electricity industry's transformation from regulation to competition.

My curriculum vitae is included as Attachment B.

Q. On whose behalf are you appearing?

A. Power Economics has been retained by the California Electricity Oversight Board (CEOB),which has asked us to testify on behalf of the CEOB, the Attorney General of the State of California, the California Public Utilities Commission (CPUC), Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company. Collectively these entities are known as the “California Parties” in this proceeding.

Q. What is your understanding of the purpose of this proceeding?

A. Having found that market prices in California were unjust and unreasonable, the Federal Energy Regulatory Commission (the “Commission” or “FERC”) adopted a method for determining the maximum level of prices to provide the basis for refunds to California’s electric utilities and their customers for prices charged by certain sellers between October 2, 2000 and June 20, 2001. The Commission’s

July 25 Order,[1] as revised by the December 19 Order,[2] adopts a method for determining the maximum hourly price for electricity purchased in the spot markets operated by the California Power Exchange Corporation (CalPX) and the Independent System Operator Corporation (CAISO) (including electricity sold to the CAISO in out-of-market purchases). The Commission instructed the CAISO to determine the marginal unit (i.e., the unit with the highest incremental heat rate) that was dispatched in the CAISO's real-time imbalance energy market (also known as the BEEP stack[3]) and then to calculate a mitigated market clearing price (MMCP) for that marginal unit based on specific cost factors, such as the price of natural gas.

In essence, the FERC asked the CAISO to determine what the market clearing prices would have been, considering the costs of the units actually dispatched by the CAISO, if the costs of the highest cost unit, rather than the highest bid, determined the market clearing price. (We note here that the FERC has not directed the CAISO to recreate the market clearing price that would have prevailed if all units that were physically available had bid into the market. If the FERC had directed that the costs of all physically available units be considered, the result would have been more consistent with a competitive market outcome

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[1] *San Diego Gas & Electric Company, et al.,* "Order Establishing Evidentiary Hearings Procedures, Granting Rehearing in Part, and Denying Rehearing in Part," 96 FERC ¶ 61,120 (2000) (July 25 Order).

[2] *San Diego Gas & Electric Company, et al.,* "Order on Clarification and Rehearing," 97 FERC ¶ 61,275 (2001) (December 19 Order).

[3] The acronym "BEEP" comes from the name of the software (the Balancing Energy and Ex-post Pricing software) used by the CAISO to dispatch energy bids submitted to the CAISO in connection with bids in the CAISO's ancillary services and supplemental energy markets.

and would have resulted in significantly lower market clearing prices and higher refunds.)

B. PURPOSE AND SUMMARY

1. Purpose

Q. What is the purpose of your testimony?

A. In our rebuttal testimony, we will discuss the foundational and analytical errors in the testimony of certain witnesses who criticize the CAISO's calculation of the MMCPs. We will further discuss why the alternative approaches for estimating MMCPs offered by these witnesses yield improper and inflated MMCPs that should be disregarded by the Commission.

Q. Which witnesses will you rebut?

A. We will rebut the following witnesses:

1) Professor Charles J. Cicchetti,
2) Dr. Judith B. Cardell,
3) Dr. Richard D. Tabors,
4) Dr. Scott T. Jones,
5) Mr. Seabron C. Adamson, and
6) Mr. Jeffrey Tranen.

We will refer to the parties represented by these witnesses collectively as the "SELLERS", although we also make specific references to particular sellers and to the witnesses of particular sellers.

Q. What are the major criticisms of the CAISO advanced by the SELLERS' witnesses?

A. The criticisms of the CAISO with respect to Issue 1 presented by the SELLERS' witnesses can be grouped into the following two points:

- using incremental rather than average heat rates; and
- defining the universe of units eligible to set the MMCP.

2. Summary of Conclusions

Q. Please summarize your conclusions.

A. Except in limited respects discussed in the California Parties' responsive testimony, the CAISO has correctly interpreted and implemented the Commission's July 25 Order in calculating the MMCPs. In performing its task, the CAISO has calculated maximum hourly prices consistent with the Commission's orders and competitive market principles, given the structural characteristics of the electricity market in California and the Commission's direction that there should be no consideration of the costs of generators that were physically available but did not sell or bid into the CAISO's real-time imbalance energy market.

a) The CAISO Correctly Interpreted the Commission's Orders and Properly Used Incremental, Rather Than Average, Heat Rates.

The Commission has reviewed and approved the method by which the CAISO determines a heat rate curve from the data submitted by generators. This is not an issue that should be the subject of any controversy in this proceeding. Nevertheless, if there is any doubt whatsoever on this point, the Judge and the

Commission should rely on the CAISO's incremental heat rates, because using the incremental heat rates, rather than the average heat rates that SELLERS propose, will provide a better proxy for the prices that would have existed in a competitive market. The Commission has consistently recognized in this proceeding that competitive prices generally equate to the marginal cost of the last unit of production. *See, e.g.*, June 19 Order,[4] 95 FERC at 62,560. For instance, in its December 19 Order, the Commission reaffirmed that the reserve deficiency proxy price calculation was to determine the marginal cost associated with the unit serving the "last increment of load." December 19 Order, 97 FERC at 61,172 n.6. Incremental heat rates, as used by the CAISO, serve as the basis for marginal, or incremental, energy costs. In contrast, the use of average heat rates, as advocated by the SELLERS' witnesses, cannot reproduce an efficient or competitive dispatch of resources for numerous and fundamental reasons:

1. Generators that produce multiple products, such as energy and ancillary services, at the same time do not have a definable average heat rate or average cost for either of those products because it is impossible to determine which of the common costs were incurred for each respective product.

2. The average heat rate method for determining MMCPs proposed by the SELLERS would allow generators to recover the variable costs incurred in the production of energy and ancillary services, all in the price of energy. Doing this would allow the generators to "double

[4] *San Diego Gas & Electric Company, et al.,* "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).

dip," leaving the significant revenues from the sale of ancillary services as pure profit.[5]

3. Because most thermal generators have declining average heat rates, the average heat rate cannot be used to emulate a competitive market where supply costs increase as quantity demanded increases. In other words, the SELLERS' interpretation of the Commission's direction to utilize the "maximum heat rate" (July 25 Order, 96 FERC at 61,517) is nonsensical because the resulting heat rate would occur at minimum load, rather than to meet the "last increment of load."

4. The SELLERS' witnesses' argument for average heat rates rests almost entirely on the unsupportable claim that use of incremental heat rates would not allow generators to recover their average costs.

b) The CAISO Correctly Interpreted the Commission's Orders and Properly Limited The Types Of Units That Can Set The MMCP To Those Dispatched By The CAISO In Real time.

In its July 25 Order (96 FERC at 61,517), the Commission directed the CAISO to determine 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 . . . ." In its December 19 Order, the Commission modified its approach slightly by directing that the maximum cost after considering gas prices, rather than just considering the maximum heat rate, should be the determinant. In

[5] In its December 19 Order, the FERC recognized the possibility of double recovery, stating, "As a matter of policy and in an effort to avoid the gaming inherent in hybrid markets, we will require that the entire portfolio choose to be under cost-of-service or under market-based rates." 97 FERC at 62,215.

calculating the MMCP cap in a manner that was consistent with the Commission's July 25 and December 19 orders, the CAISO correctly excluded units that were not dispatched by or bid into the CAISO's real-time imbalance energy market. The Commission's mitigation mechanism thus comports with its theory of trying to approximate prices that would have existed in a competitive market, because it is the real-time imbalance energy market that supplies an additional unit of energy to meet an additional unit of load and, as such, determines the market clearing price.

Given the Commission's direction to exclude supply outside of the real-time imbalance market, there should no issue concerning the universe of units that are eligible to set the MMCP. Nevertheless, if there is any doubt on this point, the Judge and Commission should rely on the CAISO's use of the BEEP stack, as it is that method, rather than the proposed inclusion of additional generating units, that will provide the best proxy for the market clearing price that would have existed in an efficient, competitive market for the following reasons.

1. The only supply that can clear the market and set the market clearing price in real time is supply that has not been dispatched or contracted prior to real time. Thus, for example, all PX and OOM transactions entered prior to real time constitute sunk costs that cannot set the real-time energy market clearing price.

2. Stated another way, only units that the CAISO could call on to meet an additional increment of demand can set the real-time market clearing price. This would exclude units providing residual or uninstructed imbalance energy, energy dispatched in blocks, or energy from unspecified sources.

3. In a competitive market, the additional energy resulting from bilateral and other non-real time transactions operates to shift the demand curve for CAISO real-time imbalance energy to the left thereby lowering the price at any level of demand. Including units sold in markets other the CAISO real-time imbalance market is little more than an attempt to artificially change demand in the CAISO real-time imbalance market , and thus fails to provide a correct estimate of competitive market clearing prices.

II. THE TESTIMONY OF THE SELLERS' AND CALIFORNIA GENERATORS' WITNESSES IS BASED ON INCORRECT ECONOMIC THEORY

Q. Please discuss how the SELLERS' testimony is based on incorrect economic theory.

A. In essence, the SELLERS' witnesses' testimony concerns two fundamental economic issues that are facing the Commission:

1. how a market clearing price is determined in a competitive electricity market, and

2. what generating plants should be included in the universe of plants that could set this market clearing price.

With respect to these two issues, the SELLERS' witnesses repeatedly err in basic economic theory involving four economic theory questions that, though abstract, are crucially important in this proceeding. The four questions are as follows:

1. What are sunk costs and why are sunk costs not included in efficient economic decision making?
2. How does a competitive market work?
3. What firms should be included in a supply curve and how should producers that are not included in the curve be represented?
4. What is a market clearing price and how is it determined in a competitive electricity market?

A. SUNK COSTS

Q. Is any one of these questions more fundamental than the others?

A. Yes. The role of sunk costs in economic decision making is the most fundamental of the above questions. A proper understanding of the role of sunk costs is central to an understanding of economic decision making, production costs, and price formation. The fact that SELLERS' witnesses have neglected this basic concept underlies many of their errors.

Q. What are sunk costs and why are sunk costs not included in efficient economic decision making?

A. The sunk cost principle says that economic decision making must be forward looking only. Anything that has already happened, cannot be undone and therefore should not be factored into the decision whether to produce or not and at what price. All past decisions, commitments, and costs are sunk. Paul Samuelson and William Nordhaus state this principle succinctly in their introductory textbook, *Economics* (Paul A. Samuelson and William D. Nordhaus, 12th Edition, McGraw-Hill Book Company, 1985) at page 517:

> Economists stress the "extra," or "marginal," costs and benefits of a decision, saying:
>
> > Let bygones be bygones. Don't look backward. Don't moan about your sunk costs. Look forward. Make a hard-headed calculation of the extra costs you'll incur by any decision and weigh these against its extra advantages. Cancel out all the good things and bad things that will go on anyway, and make a decision based on future costs and benefits.

The application of this principle of sunk costs often involves a time dimension in that prior to a certain time, or event, a cost may be variable because it can be avoided. What changes is not the cost but the ability to make the cost other than what it is. Once the cost has been incurred, it becomes a sunk, or fixed, cost.

1. Startup and No-load Costs

Q. Can you give an example of the sunk-cost principle as it applies to startup and no-load costs?

A. Yes. Drs. Jones (Page 5, footnote 8) and Cicchetti (Page 27, lines 14-16) argue that startup costs should be included in the MMCPs, and all of the SELLERS' witnesses advocate using average heat rates, which include minimum load costs.[6] The startup costs and minimum load costs of the electricity generators discussed by these witnesses provide examples of costs that are both variable and fixed.

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[6] In its December 19 Order, the Commission again made clear that start-up costs were not to be included in the calculation of the MMCP. 97 FERC at 62,212. We have included a discussion of startup costs to illustrate the importance of a proper

The cost of starting a generator is a variable cost before the generator is started. So long as the generator is not running, the operator has the ability to choose whether to incur the costs of starting it. Once the generator is started, the startup costs become fixed, or sunk, because the decision has been made, the generator has been started and the costs have been incurred. At this point nothing can be done to make the costs go away, so they should no longer affect any future decision.

Similarly, when a generator is running at minimum load, it incurs a certain level of fuel costs. At that point, these minimum load costs have become sunk with respect to the decision to increase output. The economic cost associated with the decision to increase output is the increase in fuel costs that will occur as a result. This additional cost is the incremental, or marginal, cost. It is the only relevant economic cost for the operator at this point because it is the only cost that he can affect by his decisions. As we will discuss more fully below, because only these incremental costs are directly associated with the operator's decision to produce or not to produce another increment of energy, they are the only production costs that would enter into the determination of a market clearing price in a competitive market.

2. Pumped Storage

Q. Please explain how the principle of sunk costs applies to pumped storage.

A. SELLERS' witness Dr. Tabors provides another example of irrelevant sunk costs in his discussion of pumped storage. On page 16, line 6, with reference to the

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understanding of the sunk-cost issue.

LADWP pumped storage generation, Dr. Tabors states: "The pragmatic issue is, then, what did it cost the LADWP to provide the energy."

For the purposes of electricity generation, the decision to pump the water uphill is made by comparing the costs of pumping the water uphill with the expected revenue from the electricity that will be generated when the water runs downhill. Before the pumping takes place, the decision to pump is a variable cost based on the cost of pumping and the expected future price of electricity. Once the water has been pumped uphill, the cost of the pumping becomes an irrelevant, sunk, fixed cost. The decision to pump cannot be undone and the rational operator will direct his attention toward determining the best time to let the water run downhill, while completely ignoring the sunk cost of pumping. The question ". . . what did it cost the LADWP to provide the energy?," is not an electricity pricing issue, pragmatic or otherwise.[7]

3. Purchases of OOM Electricity in Advance of Real time

Q. Does this concept of sunk costs apply to contractual agreements to supply electricity, such as the bilateral agreements entered into between the CAISO and the OOM suppliers in advance of real time?

A. Yes. The principle that decisions, once made, should be ignored in favor of decisions that have not yet been made, applies equally here. Accordingly, any OOM purchases in advance of real time represent sunk costs. As we will discuss below, a market clearing price can only be set by the interaction of ongoing

[7] Although the Commission's December 19 Order clearly states that hydroelectric generators are price takers, we have included this discussion to provide an additional illustration of an improper understanding of the sunk-cost issue. 97 FERC at 62,192.

economic decisions; that is, by decisions to consume and to supply that are still variable. Just as the only costs that count in economic decision making are costs that have not yet been sunk, the only electricity supply that is relevant to setting a market clearing price is supply that has not already been contracted for at an agreed price for an agreed amount. Once the price and quantity have been agreed upon, this decision becomes sunk and the block of electricity becomes a sunk cost of the total electricity supply.

Q. Your testimony is clear that OOM purchases in advance of real time do not factor into the determination of the marginal unit in real time. What about OOM purchases in or near real time?

A. While OOM purchases in or near real time may not represent sunk costs, there are additional reasons why units supplying OOM energy—whether in real time or not—should not be considered for purposes of setting the MMCP. These reasons are addressed later on in our testimony.

4. PX Transactions

Q. Can the price of energy from a unit purchased in the day-ahead PX market set the market clearing price in the CAISO's real-time imbalance energy market?

A. No. On page 15, line 18, of his testimony, Dr. Tabors refers to, "our preferred scenario in which the universe of units includes the BEEP, OOS and OOM, and the CA PX units." This statement provides another example of ignoring the principle of sunk costs. Day-ahead contracts are made for electricity delivery on the next day at an agreed-upon price and quantity and are a sunk cost by the time of actual generation in real time. At the time immediately before the electricity is delivered (i.e., generated and consumed), there will usually be discrepancies between the total amount of electricity being demanded and the total amount being supplied. The discrepancies will be made up by spot transactions in the CAISO's real-time imbalance energy market. It is these balancing transactions that equate the total amount of energy being generated with the total amount of energy being consumed in real time and, therefore, set the market clearing price in the CAISO's real-time imbalance energy market. If both the day-ahead and real-time markets were smoothly functioning and efficient, one would expect the day-ahead market and balancing market to be closely linked; however, the market clearing price for the energy at the time that it is actually generated and consumed can only be set in the CAISO real-time imbalance energy market.

Q. Can you provide an example?

A. Yes. Suppose that in the real-time market, one of the suppliers who has contracted to sell power through the PX day-ahead market finds that his generator has failed and the quantity being supplied is 200 MW less than the quantity contracted for. The balancing market will show this discrepancy as 200 MW of excess demand and the CAISO will purchase, all in real time, 200 MW of power to make up the deficiency. The market price will be set by the (marginal) transaction that takes place in the CAISO real-time imbalance market that balances the quantities supplied with the quantities demanded.

Because the balancing market was not clearing at the prices set in the day-ahead market, the day-ahead prices could not be called market clearing prices in the balancing market. It is because the CAISO's balancing market's operations clear the entire market for all energy in California at the time that the energy is actually produced and consumed, that the price it sets is called the "market clearing price." The day-ahead market cannot clear (balance) the actual market at the time of production and consumption because that day-ahead market cannot change its prices to compensate for real-time changes in supply and demand at the time of production and consumption.

B. COMPETITIVE MARKETS

Q. What is a competitive market, what are its characteristics and how does it work?

A. The term "competitive market" is often used in a way that implies that a market is both competitive and efficient. In our opinion, the references to competitive markets and competitive pricing in the Commission's Orders mean a market that is efficient as well as competitive. In this testimony, we also use the term competitive market in the sense of competitive and efficient unless we note otherwise.

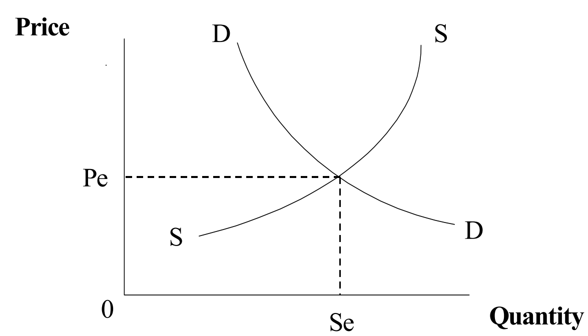
1. Markets Should Be Both Competitive and Efficient

Q. Please define the characteristics of a market that is both competitive and efficient.

A. An efficient, competitive market is generally taken to be the ideal and most desirable form of market. In this market all buyers and sellers are price takers. As we illustrate in Diagram 1, a single visible market clearing price is determined by the intersection of aggregate supply and aggregate demand curves, where the supply curve is the sum of all producers' supply curves and the demand curve is the sum of all consumers' demand curves. The supply curve shows how much producers would supply at each given price. In an efficient market, each producer expands or contracts output until the given market price equals the incremental cost of producing the last unit of output. In this market, producers always produce where price is equal to their incremental (or marginal) cost because competition from other suppliers forces them to do so. Intermediate microeconomics textbooks usually provide a mathematical proof that this market structure is the most efficient possible and jointly maximizes the economic well-being of both producers and consumers. In this market, no one can do better for himself without causing others to lose more than he gains, something that economists would refer to as a deadweight loss.

Diagram 1

In a Normal Market, Price Is Determined by the Intersection of Supply and Demand



2. Competitive Markets Are Not Necessarily Efficient

Q. Are competitive markets necessarily efficient?

A. No. Very inefficient markets can be highly competitive and vice versa. A primitive bilateral barter market can be competitive but have high transaction costs, and the absence of a single visible price will ensure large deadweight losses. Markets that allow the substantial exercise of market power can also be highly competitive. In such a market, production is sufficiently concentrated to allow the producers to profitably exercise market power by withholding supply, while still competing against each other. Such a market may be favored by the producers, but it is still inefficient and harmful to consumers. Another basic economic theorem (Henderson, James M. and Richard E. Quandt, *Microeconomic Theory: A Mathematical Approach, 3rd Ed.*, 1980, McGraw-Hill, New York, pages 306-308) states that whatever a monopoly supplier gains by raising a price above the efficient competitive level, the loss to consumers must be greater than the gain to the supplier. This is a deadweight loss of the type that does not exist in an efficient competitive market, as we discussed above.

C. SUPPLY CURVES

Q. What is a supply curve? What firms should be included in a supply curve and how should producers that are not included in the curve be represented?

A. In the competitive market that we have just described, each producer is a price taker and makes the greatest profit, or loses the least amount of money, by always adjusting production so that the price (that he must take as given) is equal to the firm's marginal cost. The industry supply curve for a particular product is the sum of the marginal cost curves of the firms in the industry. A supply curve tells us how much of a product would be supplied at any given price. It is thus a forward-looking concept. It does not represent some quantity of output that has been contracted for in the past. Rather, it is a statement about future behavior resulting from the interaction between competing producers in an efficient competitive market. It shows us the quantity of something that will be produced by an identifiable number of firms as a result of each firm attempting to maximize its own profit when confronted by different prices and a sufficient number of competitors.

1. Supply Curves Only Exist in Competitive Markets

Q. You have referred to producers in a competitive market in your description of a supply curve. Does a market have to be competitive to have a supply curve?

A. Yes. A supply curve only exists in a competitive, efficient market. It is the outcome of competition. All firms have marginal cost curves, no matter what the market structure. A firm with market power, like a monopolist, has a marginal cost curve, but not a supply curve. A monopolist (in the absence of price regulation or two-part pricing) never prices at marginal cost. Rather, a monopolist picks the most profitable price by looking at whether or not the consumers of his product have any alternative. The monopolist's profit maximizing price and quantity supplied will change, not because of costs, but because of the available substitutes and the relative importance of his product to consumers.

Q. Could a market supply curve be based on average variable costs instead of marginal costs?

A. No. Only marginal cost curves can indicate how producers would react to different prices.

Q. Are any complications introduced by generators producing ancillary services as well as energy?

A. With respect to the generators in this case, most of the generators produce ancillary services as well as energy and do not even have an identifiable average variable cost curve. As we discuss below in section III. A. 2., it is impossible to sensibly allocate total fuel costs between the production of ancillary services and the production of energy because both products are produced at the same time using the same fuel. Therefore, one could not practically use the average variable cost curves as supply curves even if the proper application of economic theory was not a consideration.

2. Bilateral Agreements Such as OOM Purchases Shift the Demand Curve and Lower the MMCP

Q. You have drawn a supply curve which represents the behavior of firms in a competitive industry. How would you represent an increase in the total supply that resulted from bilateral agreements or contracts made for supply that was in addition to that being produced by the firms represented in your supply curve?

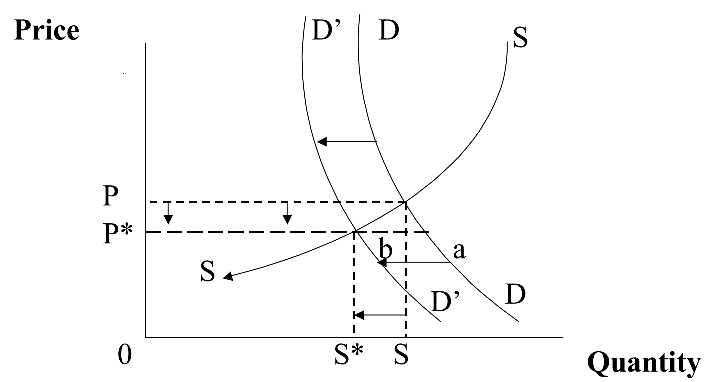
A. This would be an increase in the aggregate amount of energy being supplied, although not an increase in supply to the CAISO real-time imbalance energy market. Such an increase could be represented two ways: (1) The increase could be shown as a horizontal shift out of the supply curve as if the addition were a zero price block; and (2) The increase could be shown as a reduction in the demand for energy from the BEEP stack market—the CAISO real-time imbalance energy market. We have chosen to use this second approach for our illustration in Diagram 2 because we think that it more clearly shows that the new supply is not part of the supply that can set the market clearing price in the CAISO real-time imbalance market.

Q. Please explain Diagram 2.

A. In Diagram 2, we have represented the additional energy as a shift in the demand curve in the CAISO real-time energy market. The entire curve is shifted horizontally to the left such that the new curve, at every price, represents a quantity demanded that is less than the previous quantity demanded by the amount of the new supply. The addition of supply, and decrease in demand for BEEP stack energy, that results from bilateral agreements such as out-of-market ("OOM") purchases by the CAISO, can also be represented as a shift in the demand curve, as we have done in Diagram 2.

Diagram 2

In the California Electricity Market, Increasing Supply Lowers the Real-time Market Price



Note: the distance from a to b is the amount of OOM being purchased by the CAISO. This decrease in demand for CAISO real-time energy lowers the CAISO market price from P to P*.

D. MARKET CLEARING PRICES

1. The Market Clearing Price Keeps the Market In Balance

Q. What is a market clearing price and how is it determined in a competitive electricity market?

A. A market clearing price is a price that equates the quantity being demanded and the quantity being supplied. It is the price at which the last willing purchaser is willing to purchase one more unit of output and the last willing supplier is willing to supply that unit. In California during the refund period there was virtually no real-time demand response other than rolling blackouts due to the structure of the market, so we will focus our discussion on the supply response role in determining the market clearing price. Like all economic decisions, the decision to supply the market clearing unit of output is a prospective one. It does not include sunk costs. Furthermore, it is a marginal decision, involving relatively small quantities because it is a statement about a movement along the supply curve, which is a representation of the marginal cost functions of suppliers and their expected reactions with regard to producing increased units of supply as the price they face moves along their individual marginal cost curves.

Consider, for example, a situation in which the CAISO expects that in the next 10 minutes, at the existing price, the quantity of electricity being supplied will be less than the quantity being demanded. In response to this, the CAISO will increase the demand price in the real-time imbalance energy market, moving up the supply curve that has been created by producers stating how much electricity they would individually produce at different prices. The price that is required to bring forth the additional megawatts of supply, so that supply equals demand in the next 10 minutes, is called the market clearing price. This is the price that clears the market in the sense of eliminating the excess demand, i.e., the supply deficiency that would have existed at the old price. This price can be viewed as a response to the pending excess demand.

2. The CAISO's Real-Time Imbalance Energy Market Balances the Market and Produces the Ultimate Market Clearing Price

Q. How would you characterize the CAISO's balancing market based on the BEEP stack?

A. In California, the CAISO's real-time imbalance energy market, using bids from the BEEP stack, is the real-time spot market that clears the overall market on an ongoing basis (in real time) and, as such, determines the market clearing price on an ongoing basis (in real time). It is a market defined by published rules and procedures that combines offers to sell with offers to buy and whose settlement process produces a market clearing price. Therefore, the CAISO's real-time imbalance energy market is a market with a well defined supply curve.

III. THE SELLERS' WITNESSES' CRITICISMS OF THE CAISO'S DEVELOPMENT OF MMCPS FALL INTO THREE MAJOR AREAS

A. THE USE OF INCREMENTAL HEAT RATES

1. Average Heat Rates Cannot Form the Basis for Marginal Cost-Based Prices

Q. The SELLERS' witnesses have proposed the use of average heat rates instead of incremental heat rates to determine the MMCPs. Would this make economic sense?

A. No. The MMCPs represent an effort to develop maximum just and reasonable rates that reflect competitive market dynamics. The fundamental principle of a competitive market is that price equals the short-run marginal cost of the last unit of supply. The market in question is the real-time, imbalance market for electric generation. The short-run marginal costs of electric generation have been long understood, in both the industry and by the Commission, to come from the incremental costs of the generating units. Those incremental costs, in turn, are based upon the incremental heat rates of the units. This clear understanding has been clouded by the SELLERS' witnesses' erroneous and selective use of economic theory, industry practices, and the Commission's Orders and Reports.

Q. The Commission, on page 33 of its July 25 Order (96 FERC at 61,517) directs that the choice of marginal unit be based on "…the maximum heat rate of any unit dispatched each hour in the real-time imbalance market.…" In your opinion, was the Commission referring to an average heat rate?

A. No. We do not see how the Commission could have been. The efficient dispatch of power systems replicates the operation of efficient competitive markets. Even if it were possible to structure some form of market based on average heat rates, it could not produce an efficient dispatch of the system and could not be an efficient market because the average costs are so very different from the incremental costs and it is the matching of incremental costs to incremental demand that produces an efficient competitive market outcome.

2. SELLERS Misuse Economic Theory

Q. The SELLERS' witnesses have testified that economic theory tells us that firms will not operate if they are given a price that is less than their average variable costs. Does economic theory tell us that firms will not produce at a point where the price, and the firm's marginal costs, are less than the firm's average variable costs?

A. Yes. In the simplified world of static, single-product firms, a firm will not produce a product unless it can recover the average production costs. This principle does not apply to multi-product firms, and, in the real dynamic world of electricity generation, it does not apply to a decision of whether to produce in any given increment of time even if the firm is a single or multi-product firm.

In this proceeding, SELLERS' witnesses distort and misuse economic theory in two major ways.

1) Under the erroneous assumption of single product firms, the witnesses argue for the use of an average variable cost that is not entirely variable.

2) The witnesses assume that each generator is a single product firm, whereas generators can and do produce multiple products such as imbalance energy and ancillary services.

a) Variable Costs Must Vary

Q. Please explain the first misuse of theory--that the SELLERS' witnesses are not properly excluding nonvariable costs from their definition of variable cost.

A. The SELLERS' witnesses have argued that the MMCPs should be based on average heat rates and Mr. Adamson (Page 3, lines 18-19 and throughout) and Drs. Jones (Page 5, footnote 8) and Cicchetti (Page 27, lines 14-16) have further argued that the startup costs should, in some manner, be included in the MMCPs.[8] Startup and minimum load costs are not variable for plants in the real-time energy market. The energy in the real-time market is supplied by units moving between minimum and maximum loadings. Thus, the variable fuel costs associated with

[8] As noted earlier in our testimony, the Commission has clearly excluded startup costs from the calculation of MMCPs. We discuss SELLERS' witnesses' testimony concerning startup costs to demonstrate how these witnesses have applied incorrect economic theory.

the decision to change output in real time do not include those costs which the SELLERS' witnesses wish to add to the MMCP determination.

b) Multi-Product Firms Do Not Have Average Costs

Q. Please explain the second misuse of economic theory.

A. The second misuse of economic theory is that these witnesses have ignored a fundamental aspect of electric generation for the real-time market: it is part of a production process that provides more than one product or service. That is, generators who supply imbalance energy also can and usually do supply ancillary services. A 300 MW generator that is supplying 200 MWs of energy could also be supplying regulation or reserve service. Both services provide revenues and, thus, the decision to produce or not depends on the comparison of the revenues from both sources with the total variable costs.

Q. When a generator is producing both imbalance energy and an ancillary service, is it possible to determine how to allocate fuel costs as advocated by the SELLERS' witnesses for determining the MMCPs?

A. No. It is not possible. Some accounting problems may require an allocation of these costs, but the result will be without economic meaning and will have no basis. Economists call these common or joint production costs. Common costs are incurred when two or more products (energy and ancillary services) are produced from one process. Even though each product has an identifiable marginal cost curve, the common costs cannot be imputed on an economic cost basis to one product or another. The costs are just that, common. When the production of one or more products have common costs, the question of whether revenues will cover costs must be assessed on the group revenue and cost basis --

something that the SELLERS' witnesses did not do in their analysis nor did Dr. Cardell do in her analysis of cost recovery. Also, because there is no average variable cost, there can be no rule about pricing, or operating, based on average variable cost.

Q. Can you provide an example from another industry?

A. Yes. One well-known example is provided by the sheep farmer whose sheep produce both wool and mutton. There is no way to say how much of the feed cost goes to produce the wool and how much to produce the mutton, and it follows that there is no sensible way to say what is the average cost of either wool production or mutton production. To make the example more concrete, assume that the farmer pays $80 for sheep food and maintenance and sells the wool for $40 and the mutton for $60. Is it possible to say what the cost of mutton production is for this farmer? No. It is not. Following this analogy further, SELLERS' witnesses are arguing that $80 is the cost of mutton production, that the farmer should be paid $80 for the mutton, and that the farmer would not produce mutton if the market price of mutton was only $60, or any price less than $80. Pursuing this type of un-economic logic would drive the sheep farmer out of business.

Q. Please explain the common cost problem with regard to the production of energy and ancillary services.

A. Consider a generating unit before startup, anticipating supplying ancillary and imbalance energy service. (And presume that the expected revenues from both services, taken together, are expected to exceed the costs of producing them.) The plant starts up and moves to some operating level. It is just not possible to say which service incurred the costs of starting up and generating at the minimum load. The plant had to be online and running to supply either of the services, either singly or together. The costs are common to the two services. An attribution of those costs to one or the other service, or some division between them, can only be arbitrary at best.

Q. Are you saying that the SELLERS' witnesses have been arguing for a measure of fuel cost that does not exist?

A. Yes. A multi-product firm, such as a generator that is producing energy and ancillary services at the same time, does not have a definable average cost for either of the products. SELLERS' witnesses have submitted vast amounts of testimony in this proceeding asking that the Commission determine MMCPs using a measure that does not exist for any generator that produces both energy and ancillary services.

Q. If the average fuel costs proposed by the SELLERS are fully included in the determination of the MMCPs, what does that say about the treatment of the common costs of electric generation?

A. Whenever costs are common to the production of multiple products, their inclusion in an average cost measure and the assignment of that measure solely to imbalance energy generation is extremely misleading. It is an implicit assertion that the costs are totally caused by the production of only one of the products, the energy, even though a significant part of the generator's revenues may be coming from the sale of ancillary services.

At best, the SELLERS are asking for an MMCP for one product, energy, that would fully compensate them for the costs of producing at least two products. Plants that were on the margin would over-recover by an amount equal to their sales of ancillary services. Generators that were not on the margin would receive an even greater over-recovery.

Q. Have common costs, and the non-existence of average costs been widely discussed in economic literature?

A. Yes. The modern theory of common and joint costs was first clearly explained by Alfred Marshall[9] in 1890. In the early 1900s, the issue of common and joint costs was central to the arguments between Pigou[10] and Taussig[11] over railroad pricing. In 1932, von Stackelberg developed a consistent theory of production that explicitly included common costs.[12] With respect to electricity, James Bonbright and Alfred Kahn discuss common and joint costs in their respective seminal works, *Principles of Public Utility Rates*[13] and *The Economics of Regulation: Principles and Institutions*.[14] More recently, the common cost issue has played a significant role in the literature of antitrust economics and of pricing in the

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[9] Marshall, Alfred, *Principles of Economics*, Book V, Chapter VI, first published 1890, reprinted by Macmillan & Co., Ltd., London and Baltimore, 1920.

[10] Pigou, A.C., *Wealth and Welfare*, Macmillan & Co., Ltd., London, 1912

[11] Quoted in Kahn, Alfred E., *The Economics of Regulation: Principles and Institutions*, Volume 1, John Wiley & Sons, Inc., 1970, footnote on page 78.

[12] "Heinrich von Stackelberg on Joint Production," by Stefan Baumgärtner Department of Economics, University of Heidelberg, forthcoming in: *The European Journal of the History of Economic Thought* (2001).

[13] Bonbright, James C., Danielsen, Albert L., Kamerschen, David R., *Principles of Public Utility Rates*, Second Edition, Public Utilities Reports, Inc., Arlington, VA, 1988, pages 500-509.

[14] Kahn, Alfred E., "*The Economics of Regulation: Principles and Institutions*," Volume 1, Economic Principles, John Wiley & Sons, Inc., 1970, pages 77-83.

deregulated and unbundled telecommunications industry.[15] The topic is also covered in textbooks such as *Exchange and Production Theory and Use*[16] by Armen Alchian and William Allen.

c) Multi-Product Firms Do Have Incremental Costs

Q. Does the use of incremental heat rates for the MMCPs suffer from a common cost problem?

A. No. Because energy can be varied independently of ancillary service at the margin of production in the imbalance market, a plant can determine its incremental costs unambiguously by increasing the output of each product individually and observing the increase in fuel consumption. For example, a plant might be supplying a constant amount of ancillary services while increasing its energy output. Over that increment of change, the additional fuel cost would be for the additional energy only. Incremental heat rates at each level of a unit's output, and consequently incremental or marginal fuel costs, are the proper measure of the costs of the unit's incremental output. And thus, the incremental heat rates in the real-time, imbalance market can correctly be used to determine

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[15] Bailey, E.E. and Friedlaender, A.F., "Market Structure and Multiproduct Industries," *Journal of Economic Literature*, 1982, 20:1024-1048; Baumol, W.J., "On the Proper Cost Tests for Natural Monopoly in a Multiproduct Industry," *American Economic Review*, 1977, 67:809-822; Baumol, W.J., Panzar, J.C., and Willig, R.D., *Contestable Markets and the Theory of Industry Structure*, Harcourt Brace Janovich, San Diego, revised edition, 1988; Panzar, J.C. and Willig, R.D., "Economies of Scope," *American Economic Review Papers and Proceedings*,", 1981, 71:268-272; and Willig, R.D., "Multiproduct Technology and Market Structure," *American Economic Review Papers and Proceedings*, 1979, 69:346-351. 19.

[16] Alchian, Armen A. and Allen, William R., *Exchange and Production, Theory and Use*, Wadsworth Publishing Company, Inc., Belmont, California, 1964, pages 308-310.

the MMCPs free of the common cost problem associated with attempts to use average heat rates.

3. Average Cost Curves Cannot Support a Stable Market Equilibrium

Q. Please explain the problems of using average heat rates as the basis of competitive prices such as the MMCPs are supposed to emulate.

A. As we have already noted, at the margin of output the average heat rate does not represent the marginal cost of a small, incremental change in output. But, the resource allocation issue is not the only problem. With an industry that has declining average costs for the great majority of its suppliers, there can be the problem of never being able to establish a market clearing price.

The SELLERS' witnesses have noted that the average heat rate is greater than the incremental heat rate for most of the segments of the generators. They have given less emphasis to the fact that for over 80 percent of the units, the minimum average heat rate is in the last segment (full capacity output), and this is true even if the units with flat heat rate curves are excluded (CAISO Exhibit ISO-7). As an average, over the units listed in CAISO's Exhibit ISO-7, the average heat rate declines 20% from the highest to the lowest heat rate (excluding the minimum load segment in measuring the decline), and four units have declines of over 50%.

Given this shape of the average heat rate curve, the SELLERS' witnesses' interpretation of the Commission's directive to use the maximum heat rate of the unit becomes even more problematic. If a unit were dispatched at minimum load, it would have a very high heat rate. If it were called on to increase output, its heat rate would decline, in some cases precipitously. There is no way to reconcile this declining cost with the general necessary condition for a competitive market equilibrium, in which supply costs increase as quantity demanded increases.

In an electricity market, the difficulties of bidding based on average costs should be obvious, even without the multi-product firm problem that we discussed above. If the plant, with a typical 20% decrease in average heat rate, were to offer generation at its average cost based on its maximum heat rate at minimum load, it would have a high probability of never being called on to run. On the other hand, if it were to bid its minimum average cost, based on its minimum average heat rate at maximum load, it would not recover its costs whenever it was called on to run at less than full output, which would be necessary for any time this plant was on the margin and was actually called upon to make output adjustments (between intervals) for changes in the real-time imbalance market. That is, average cost-based bidding (with declining average heat rates) produces the following perverse situation: when the plant is on the margin it has (again based on the incorrect presumption that the average cost is the relevant variable by which to judge the supplier's decision) an incentive to act like a pure base load unit and either offer all the output or none.

Q. Would using incremental heat rates as a basis for competitive prices have the same problem?

A. No. Incremental heat rates are generally increasing (75% of the operational segments show increasing incremental heat rates versus less than 5% for average heat rates) (CAISO Exhibit ISO-7). Further, the cases of decreasing incremental heat rates are more often found in the lower end of the operating range, after which they increase. The result of this is that most units have operating ranges in which the output can be incrementally varied with changes in price. And such units, when basing their response on incremental heat rates, do not exhibit the perverse behavior that they would if they based their behavior on average heat rates. In the real world, incremental heat rates are consistent with competitive prices; average heat rates are not.

4. SELLERS' Witnesses Have Greatly Exaggerated the Possibility of Under-Recovery

Q. The SELLERS' witnesses have testified that the CAISO's MMCPs will often be less than the generators' average variable costs and that economic theory tells us that firms will not operate if they are given a price that is less than their average variable costs. Dr. Jones (page 8, lines 3 and 4) goes so far as to raise the specter of generators being "irrevocably harmed." Do you agree?

A. No. In the present circumstance, generators choose to run based on an expectation of prices that will occur in the future and cannot be known with certainty at the time the generator must decide to start his generating plant. Early in the morning, the generator must anticipate the day's pattern of prices. If the generator has a plant that supplies only energy and which has the characteristic that the marginal cost is always less than the average variable cost, he knows that he will lose money whenever the market clearing price for energy is less than his average variable cost if he is running and only producing the single product. He also knows that whenever the market price is higher than his average variable costs, he will make money, and whenever he can sell ancillary services in addition to energy, he may make money even when the price of energy by itself is less than his average variable cost.

Q. One of the SELLERS' witnesses, Dr. Tabors, argued, "In the real world, where the revenue is less than the costs, the units simply would not run." Exhibit No. PWX-1, page 11, lines 1-2. Is that correct?

A. As a rule, sellers produce in the expectation of at least recovering their variable costs over some operating period. For instance, a restaurant might stay open between normal mealtimes because there was an expectation that it would attract sufficient business to more than cover the costs of so operating. However, at any given time the restaurant might have no customers. This is one of the problems with Dr. Tabors', and the other SELLERS' witnesses', application of average variable costs.

When a generator starts up or bids, the operator expects to recover the startup and minimum load costs over the period of operation. But that generator does not immediately shut down the moment the price is below the average fuel costs inclusive of startup and minimum load. If the generator's revenues exceed *what is variable for that decision period*, it will continue to operate. Thus, if we look back over, say a 16-hour period of operation, the price the generator receives might indeed fall below the average fuel cost in some 10-minute intervals. But, if we examine a reasonably large block of time (averaging over many decisions to start or not), we would expect the generators to cover their costs inclusive of startup and minimum load. But with variations in market prices, we have no expectation that in every 10 minute interval the price would be above such average costs.

Q. Is this possibility of negative net revenue a major factor for generators if the CAISO's MMCPs are used?

A. No.

Q. Witness Dr. Cardell performed a study, that she and Dr. Tabors discuss, in which she describes the results as follows: "I corroborated the testimony of Dr. Tabors that many units would be unable to cover their costs a significant amount of the time." Page 29, lines 16 and 17. Is this what her study shows?

A. Like much of the testimony of the SELLERS' witnesses, the study and the testimony based on it are misleading. The results of the study would only be relevant to this case if the generators produced and sold only energy. In fact, they produce and sell ancillary services and energy to the CAISO and energy in bilateral contracts to other buyers and most of them would make money during the very times that Dr. Cardell identified as times during which they would be unable to cover their costs. In her rebuttal testimony, Dr. Berry presents information which shows the effect of adding revenues from the sale of ancillary services to the revenues from selling the full output of each unit at the CAISO's MMCPs. She found that almost all generators made positive net revenues. Dr. Berry also found that the revenues from selling ancillary services comprise a significant portion of the revenue stream for many generators.

Q. Have you reviewed the net revenue calculations that Dr. Berry performed?

A. Yes.

Q. What is your understanding of those calculations?

A. We understand that Dr. Berry calculated the net revenue that each unit would receive if it had sold all of its generation at the MMCP as calculated by the CAISO, had received ancillary service revenue equal to the lower of the MMCP or the actual ancillary service price, and had incurred fuel, variable O&M based on the unit average heat rate, MMCP gas prices, MMCP variable O&M, and MMCP risk assumptions.

A. We understand that Dr. Berry based her calculation on the entire generation of each gas-fired unit that was operated through the CAISO.

Q. Have you reviewed the results of Dr. Berry's net revenue calculations?

A. Yes. Those results show that almost all units would, under the assumptions used, have positive net revenues in almost all of the two week periods examined. The exceptions primarily relate to several small units, several RMR units (note that Dr. Berry has not considered RMR revenue) and to several weeks at the very end of the refund period where some units that have consistently earned significant net revenue earlier would have experienced minor losses.

Q. Do these calculations have any demonstrative value relative to the economic theory that you discuss in your testimony?

A. Yes. These calculations have demonstrative value in the following ways:

1. The fact that net revenue is positive over a series of hours and over joint products (ancillary services and energy) illustrates that operating losses in one hour or on one product are not only irrelevant theoretically, but are of no practical consequence. The MMCP allows sufficient revenue for units to profitably operate over a reasonable commitment cycle taking advantage of all products that can be sold by virtue of operating.

2. The fact that the units would earn positive net revenue over a commitment cycle at the MMCP price dispels any claim by the

generators witnesses that the MMCP prices are too low to represent prices that could be found in market. There is no evidence or reason to believe that the commitment and dispatch of generating units would have differed from that actually experienced if the MMCP prices had been the prevailing price.

3. The fact that positive net revenue would have been earned by so many units in so many of the commitment periods contradicts claims that the MMCPs are lower than prices would have been in a competitive market because the MMCPs have been selected only from the BEEP stack. Dr. Berry's analysis of net revenue covers the entire output of all units. Hence, even if a unit generated out of market, the fact that MMCPs based on the BEEP stack provide positive net revenue for the unit for the commitment period indicates that the MMCPs developed from the BEEP stack provide adequate compensation to all units including out of market units from within the CAISO.

Q. Are you aware that, in fact, the entire output of each generating unit was not sold into mitigated (i.e., spot) markets?

A. Yes. We do not believe that this in any way lessens the applicability or the demonstrative value of the analysis. The analysis shows that the MMCP prices would not be inconsistent with the prices in a competitive market had all output been sold into the spot market. That is all that is necessary to demonstrate that these prices are sufficient to represent a competitive market outcome – i.e., a situation where the market prices and the operation of the units is consistent. The fact that owners of generating units may have sold power in other markets – i.e., forward or bilateral markets – and may have bought gas in other markets does not alter this basic conclusion.

5. SELLERS' Witnesses Have Misinterpreted the Orders and Reports

Q. Do you agree with the testimony of the SELLERS' witnesses Adamson, Cardell (by implication in the calculated scenarios), Cicchetti, Jones, Tabors and Tranen criticizing the CAISO's use of incremental heat rates in the determination of the MMCPs as conflicting with the Commission's Orders and Reports?

A. No, we disagree. While these witnesses have claimed to base their arguments on economic theory, their conclusion ignores that fundamental tenet of economics, namely, that the price in a purely competitive market is equal to the marginal cost of the last unit of output. Throughout its rulings on price mitigation, the Commission has recognized this principle. For instance, in its June 19 Order, it stated, "Competitive markets clear at a single price, which is effectively set by the marginal cost of the last unit produced." Page 28.

It is unreasonable to interpret Commission Orders directing that the marginal unit be selected on the basis of the maximum heat rate as meaning that the Commission wanted an average cost, average heat rate measure, instead of the usual marginal, incremental heat rate measure.

Q. Have Witnesses Adamson, Cicchetti, Jones, Tabors and Tranen interpreted the Commission's orders to imply the use of average heat rates for determining the MMCPs?

A. Yes.

Q. Did these witnesses cite the Commission's Order in support of average heat rate-based MMCPs?

A. Yes. In support of their average heat rate position, witnesses Adamson (page 21, line 12-14), Cicchetti (page 39, lines 3-7), and Tranen (page 4, line 7; page 15, lines 14-15) all quoted the Commission's July 25 Order, particularly in regard to the instruction to the CAISO on page 33 of that Order and/or the July 12 Report and Recommendation of the Chief Judge on page 6. The conclusions these witnesses draw from the Commission's language are unwarranted in regard to the overall text of the Orders and Reports, as well as in the light of industry practices and the underlying economic theory.

Q. Did Mr. Adamson interpret the Commission's words in their proper context?

A. No. Mr. Adamson quotes selectively and out of context in an attempt to support his position.

Mr. Adamson states on page 21, line 20, that the Commission is silent with regard to the use of incremental or average heat rates and he takes this "silence" as allowing the novel use of average heat rates to calculate generating units' marginal costs.

The Commission may have been silent as to the term "incremental heat rate" in the July 25 Order, but the Commission did explicitly note in its June 19 Order (page 33) that, "…the [CA]ISO will be able to approximate the actual incremental cost curve of each of the generating units…." This detailed Commission incremental heat rate curve discussion in its June 19 Order was taken into the July 12 Report and the July 25 Order.

It seems nonsense to argue that language which is replete with the term "marginal cost," describes the estimation of an incremental heat rate curve in the method it directs the CAISO to use, and is generally consistent with electric industry practice and economic theory, could mean anything but incremental heat rate when referring to the heat rate of the last unit dispatched.

Q. Does Dr. Cicchetti reasonably interpret the Commission's language?

A. No. On page 39 of SEL-1, Dr. Cicchetti immediately follows the "…we will require …" quote with his statement: "This could scarcely be any clearer. The CAISO's methodology did not follow these instructions." Lines 7-8. He goes on to say that the CAISO did not choose the unit with the highest heat rate in 48.4% of the intervals. Dr. Cicchetti reaches this conclusion by switching the Commission's incremental heat rates for his own average heat rates. What he means is that the CAISO, quite properly, did not choose the unit with the highest average cost in those intervals. Dr. Cicchetti has leaped from the Commission's language to his desired result that heat rate means average heat rate. Page 39, line 9. This leap is all the more unwarranted in that seven pages earlier (dealing with a gas price sub issue), Dr. Cicchetti states: "The requirements of the July 25 Order are based on the general relationship between a unit with the highest heat rate and marginal cost." SEL-1, page 32, lines 24-25. Thus, Dr. Cicchetti has managed to interpret, as Mr. Adamson has, that the Commission's objective of marginal cost-based MMCPs means those MMCPs must be calculated from average heat rates.

Q. Does Mr. Tranen reasonably interpret the Commission's language?

A. No. On page 4, lines 7-9 of his testimony (GEN-1), Mr. Tranen states the following:

> The July 25 Order requires us to use actual operating data, not hypothetical dispatch data, for the heat rates. For each interval, I identify each generating unit's average heat rate at its actual operating level of output during that interval.

In the first sentence, Mr. Tranen takes the Commission's rejection of an "assumed economic dispatch" (the simulated re-dispatch of the system) and turns it into an instruction on heat rates. It is only reasonable to presume that the Commission wanted the CAISO to collect actual, and not hypothetical, heat rate data, and the Commission explicitly approved the collection of data on 11 different operating points. But, the collection of actual data for 11 operating points in no way implies that the heat rate to be used should be average.

Similarly, on page 10, lines 15-18 of his testimony, Mr. Tranen refers to the July 12 Report:

> Judge Wagner recommended that "[t]he actual heat rates, *rather than hypothetical heat rates* (associated with recreating the must bid requirement of the June 19 Order), [should] provide the first step in calculating the cost of the marginal unit."

Mr. Tranen uses this quote in support of the use of average heat rates for the MMCPs. But it seems clear that the Chief Judge was comparing the dispatch of marginal cost bids under a must-bid situation for prospective MMCPs (of the June 19 Order) with the determination of the MMCPs for the plant outputs that actually occurred during the historical period (October 2, 2000 through June 20, 2001). Recalling that the method the CAISO used to construct the incremental cost curve was accepted in the June 19 Order, to conclude that the Judge's words "actual" and "hypothetical" mean the Judge is rejecting incremental heat rates and establishing average heat rates (as the standard for marginal costs) flies in the face of both logic and industry practices.

Q. Is Mr. Tranen's testimony consistent with his own misinterpretation of the Commission's language?

A. No. At page 46, line 14-16, of his testimony, Mr. Tranen recommends an approach for defining the heat rate used for setting the market clearing price which would be ". . . simply to 'fill in the curve' by taking the average of the heat rate used in the interval before and the heat rate used in the interval afterward." In this case, Mr. Tranen is recommending a calculated, hypothetical heat rate that does not reflect the actual operation of units in the power system.

Q. Did the CAISO perform a hypothetical dispatch in its determination of MMCPs?

A. Of course not. The CAISO calculated the MMCPs from the actual (based on information supplied by generators) instructed output levels of the generators. The accusation of a hypothetical dispatch is groundless.

Q. Do Commission Orders issued since the July 25 Order address this issue?

A. Yes. In its Rehearing Order issued December 19, 2001, the Commission reaffirmed that the whole purpose of the proxy price calculation was to determine the cost associated with serving the last "increment of load," or the marginal cost, from units dispatched by the ISO. December 19 Order, 97 FERC at 61,172 n.6. In another order issued the same day dealing with the CAISO's filing in compliance with the June 19 Order, the Commission approved those filings, thereby approving the CAISO's use of incremental heat rates for purposes of developing representative proxy prices. Order Accepting in Part and Rejecting in

Part Compliance Filings, 97 FERC ¶ 61,293 at 62, 371 (December 19, 2001). These Orders confirm the Commission's clear intent to use incremental heat rates.

6. Conclusion Regarding Incremental Versus Average Heat Rates

Q. Please state your conclusion regarding the use of incremental versus average heat rates in the determination of the MMCPs.

A. We conclude that incremental heat rates serve as the basis for incremental energy costs, synonymous for practical purposes with marginal costs. The CAISO's MMCPs accurately reflect this approach resulting in an approximation of the market clearing prices that would have occurred (assuming accurate cost inputs) had the market been competitive. Because competitive prices are equal to the marginal cost of the last unit of production, the CAISO correctly performed its calculations based on incremental heat rates. This method is the only economically sensible approach and represents the plain interpretation of the Commission's intent in asking the CAISO to calculate the MMCPs.

The SELLERS' witnesses, on the other hand, have selectively used the Commission language to argue, or in one case simply jump to the desired conclusion, that the Commission wanted a calculation based on average heat rates. They have more than compounded their errors of interpretation with erroneous economic analysis. Their analysis was almost entirely based on the unsupportable claim that incremental heat rate-based MMCPs would not allow generators to recover their variable costs. More importantly, they failed to recognize that generators can, and often do, produce multiple products: imbalance energy and ancillary services—a situation in which the SELLERS' preferred average variable costs do not even exist. With regard to cost recovery, the SELLERS' witnesses ignore both the revenues they receive from ancillary services and the problem arising when costs are incurred commonly by simultaneously producing two or more outputs.

B. DEFINING THE UNIVERSE OF UNITS ELIGIBLE TO SET THE MMCP

Q. What is the importance of the set of units that are included, or excluded from the analysis?

A. The set of units included in the analysis determines the definition and range of costs available to set the MMCP.

Q. What is the effect of the SELLERS' recommendations?

A. The combined effect of the SELLERS' recommendations is to expand the universe of units that can set the MMCP and to create a decision rule that results in the highest measurement of cost of the most expensive unit irrespective of whether the unit is actually setting the market clearing price.

1. Professor Cicchetti's Criticism of the Relevant Market is Invalid

Q. Is Professor Cicchetti's criticism that the CAISO unjustifiably excluded units from the universe of potential units that can set the MMCP valid?

A. No. Professor Cicchetti testifies that, "The first conceptual error in the CAISO is (sic) approach for determining MMCP is its reliance on Dr. Hildebrandt's definition of the relevant market--and resulting exclusion of a substantial portion of the market that, from a factual perspective, cannot be justified." Page 15, line

13-16. Dr. Hildebrandt did not need to define "the relevant market." The Commission defined the scope of Dr. Hildebrandt's analysis at page 33 of its July 25 Order, stating, ". . .we will require that the [CA]ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real-time. . . ." Real-time dispatch at the CAISO is accomplished using the BEEP stack.

Q. Has the Commission given any other confirmation that the appropriate universe of units for this purpose is the BEEP stack?

A. Yes. In its December 19 Order, the Commission rejected SELLERS' requests for rehearing on this issue. Duke and Dynegy, for example, argued that the Commission should not base the MMCP for all ISO and PX markets on the basis of units dispatched from the BEEP stack, and the Commission rejected those arguments. December 19 Order at 62,202-203.

Q. Professor Cicchetti argues at page 15, lines 17-20, that, "Dr. Hildebrandt truncates the market he analyzed for establishing his reference MMCP by using a market definition that simply does not reflect the actual supply and demand parameters of the market during the refund period." Do you agree?

A. No. In this proceeding Dr. Hildebrandt was not required to determine a relevant market as if this were a merger or anti-trust case; he was asked to determine the hypothetical competitive market clearing price in a FERC defined specific spot market (the CAISO's real-time imbalance energy market).

Dr. Hildebrandt did not "truncate the market." He did not exclude any supply of electricity in California, or into California, from his economic analysis. Nor did he exclude any source of demand. But, for the purposes of determining the

MMCP, he correctly used only those generators whose bids were reflected in the CAISO's BEEP stack, i.e., energy bids submitted to the CAISO in connection with the CAISO's ancillary services auctions and supplemental energy bids.

Dr. Hildebrandt, at page 45, beginning on line 6, states, "There are six sources of Energy that the [CA]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) Energy from units under AGC,
3) real time energy bids dispatched out of merit order (i.e., out-of-sequence or "OSS" 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").

Dr. Hildebrandt provides a detailed explanation for the exclusion of each of these sources of energy from being used to set the MMCP in the following pages of his testimony. These six sources of energy are properly excluded because they could not be marginal. Their exclusion has nothing to do with defining a relevant market. The whole exercise of identifying a market clearing price comes down to identifying the plant that would supply (or remove) the increments of supply necessary to keep the system in balance in real time in a competitive, efficient market. The CAISO was required by this Commission to identify the incremental supply that would be called on to meet an increment in demand. Any plant that could not be called on to meet an increment of demand, i.e., did not have an energy bid in the CAISO's real-time imbalance energy market, is properly excluded.

Far from truncating the market, Dr. Hildebrandt properly recognized that the market clearing price is set by the marginal running cost of the last unit of dispatch in the real-time imbalance market--precisely what the Commission's July 25th Order said should be done. Other than small changes that are followed through "regulation" which is treated as a separate ancillary service, changes in real-time dispatch take place in the operation of the BEEP stack. The appropriate question is not about market definition. Rather it is about how a market clearing price is determined in a competitive market.

2. Dr. Cicchetti Recommends Including OOM

Q. What is wrong with Dr. Cicchetti's suggestion that blocks of out-of-market OOM transactions, that were more costly than the price in the CAISO's real-time imbalance energy market, set the market price when this type is the most expensive?

A. The CAISO looked only at plants whose bids it could dispatch in the real-time imbalance market that thus could set the market clearing price. Blocks of power owned by sellers who chose not to bid into the BEEP stack that could not be dispatched by the CAISO and were not supplied competitively could not set the market clearing price.

3. OOM Purchases Shift the Demand Curve

Q. Would your earlier description of a new supply causing a shift in the demand curve, apply to all purchases of OOM energy by the CAISO?

A. Yes. The SELLERS' witnesses argue that electricity supplies from OOM transactions could set the market clearing price, are properly represented by extending the supply curve of electricity, and should be included in calculations of the MMCP whenever the price of the OOM is greater than the price calculated by the CAISO. This argument is implied in the testimony of Jones, Adamson, Tabors, and Tranen, and Professor Cicchetti presents a diagram (page 17) showing supply curves that include OOM purchases. Professor Cicchetti uses these diagrams to support his position that the addition of OOM causes an increase in the market price that the MMCP should properly be based upon. This is all incorrect economics.

As we discussed above, the OOM purchases represent an *addition* to the California market supply and a decrease in the demand for energy in the CAISO's real-time imbalance market, but it is an addition of energy in a form that cannot be part of the BEEP stack and the CAISO's real-time imbalance market. Out of state OOM energy is delivered in the form of a block, not as the marginal cost curve of an identifiable additional plant that is competitively bid into the market in the form of inc's and dec's. In this instance, such an addition to supply can be represented as a decrease in the demand for CAISO real-time energy, accompanied by a decrease in the market clearing price, never an increase.

The same is true for the 8 percent of OOM and OOS the ISO purchased from gas-fired units within the ISO control area. Hildebrandt, page 14, lines 15, 16 and pages 48, line 16-page 49, line 19. These sellers have chosen to remove themselves from the competitive real-time imbalance market and to sell to the CAISO non-competitively. This OOM energy cannot flow through the incremental, bid-based CAISO real-time energy balancing market and so set the market clearing price, because its sellers have chosen to not participate in this market. The OOM transactions provide an example of energy supplies that are not part of any competitive market supply curve.

Q. Is there any other reason why is it appropriate to exclude OOM transactions?

A. Yes. Essentially, the OOM transactions are a bilateral contract between the CAISO and market participants. Unlike the price formation in the BEEP stack, governed by FERC tariff, there are no rules for price formation for OOM transactions.

4. Dr. Jones Recommends Inclusion of Plants That Do Not Follow Load

Q. At the bottom of page 14, Dr. Jones states that if the OOM and OOS transactions ". . . are to be considered subject to refund, the impact they had on the marketplace ought to be considered." Do the CAISO results reflect the impact of these transactions?

A. Yes. As with any other source of supply, for example the output of nuclear power plants or pumped storage hydro, these supplies affect the marketplace by making the market clearing price less than it would have been otherwise.

As we have shown in Diagram 2, the effect of adding non-load following blocks of electricity is to shift the demand curve for CAISO-supplied energy to the left, toward the origin. In addition, the shifting demand curve affects what plant will be on the margin and causes the market clearing price to be reduced. The actual cost of the block of power that is added does not enter into price determination directly. Diagram 2 corrects the diagrams presented by Professor Cicchetti and

Mr. Adamson in which the additional supply is shown as an extension of the market supply curve facing the CAISO.

5. Mr. Tranen Recommends Including Residual Energy

Q. Can residual energy be the load following unit as Mr. Tranen suggests?

A. No. Mr. Tranen argues that, "Another type [of additional sources of energy] would be Residual Energy, which Dr. Hildebrandt also would exclude from consideration." Page 37, beginning at line 4. Residual Energy is correctly defined by Mr. Tranen as "energy generated by a unit that the [CA]ISO has instructed to shut down or ramp down to its scheduled level, but that physically cannot stop generating energy as quickly as ordered by the [CA]ISO. Residual Energy is the 'extra energy' generated while the unit is trying to reach its scheduled level." Page 37, lines 5-9. In this case, the unit is clearly being dispatched not to meet load, but to meet other CAISO operating objectives.

6. Hour-Ahead Markets Cannot Perform Real-Time Balancing

Q. On page 34, beginning in line 6, Professor Cicchetti states that "in choosing the marginal unit in each interval, the CAISO ignored those units that had a final Hour-Ahead Schedule if those units did not also have an acknowledged incremental or decremental dispatch instruction. This resulted in intervals where the CAISO found a unit to be the marginal unit even though it had a heat rate that was lower than the heat rate of a unit that was actually scheduled in the real-time market." Does this phenomena reflect a failing in the CAISO's method?

A. No. This reflects a failure in the structure of electricity markets in California. If the California electricity industry were structured in the form of a single efficient market into which all generators bid, then (ignoring system operating requirements) the most expensive unit would always be following load at the margin and less expensive (in terms of marginal running cost) units would be running flat out. In California, the Power Exchange (PX) was structured as a separate market from the CAISO balancing market. The CAISO correctly calculated the MMCPs given the structure that existed in California.

Q. On page 44, lines 6-8, Professor Cicchetti states that, "The CAISO's treatment of OOS and RMR units also caused its MMCP calculation to be understated. Competitive markets would seek to internalize locational reliability." Do you agree?

A. No. Competitive markets do not generally, by themselves, internalize externalities or public goods such as locational reliability. Generally such costs are recovered, and possibly subsequently internalized, by the imposition of a charge imposed by a regulator or oversight body. In electricity production, such charges are often imposed by a system operator and recovered through an additional charge to customers called an uplift charge. Such a charge would not affect the system dispatch or the market clearing price seen by generators.

7. Dr. Tabors Recommends Including Pumped Storage Hydro

Q. Dr. Tabors states (page 7, line 19) that "The CA ISO excluded from its calculations of the MMCP, units that were significant suppliers of energy on peak to the CA ISO…" Does this statement have any relevance for these proceedings?

A. No. The operation, or not, of any plant that was not on the margin and could not have been on the margin is simply not relevant to this proceeding. During the time of system peak, a large amount of energy was being supplied by nuclear units. These "significant suppliers of energy on peak" are also irrelevant to this proceeding. During peak hours, most of the energy may be coming from large base load plants that usually run only at full output. Even though they provide a significant amount of the energy being supplied and are an important source of energy, we have not heard anyone suggesting that they be included in the estimation of the MMCPs.

Q. In his discussion of omitted suppliers of energy, Dr. Tabors states at page 7, lines 21-23, that, "Specifically, the CA ISO excluded the pumped hydroelectric units of the Los Angeles Department of Water and Power (LADWP)." Could a pumped storage unit be the marginal unit and set the market clearing price in a competitive market?

A. No. As we discussed above, once the water is pumped, the pumping costs become “sunk” and the unit has no definable production cost and no incremental marginal cost curve.

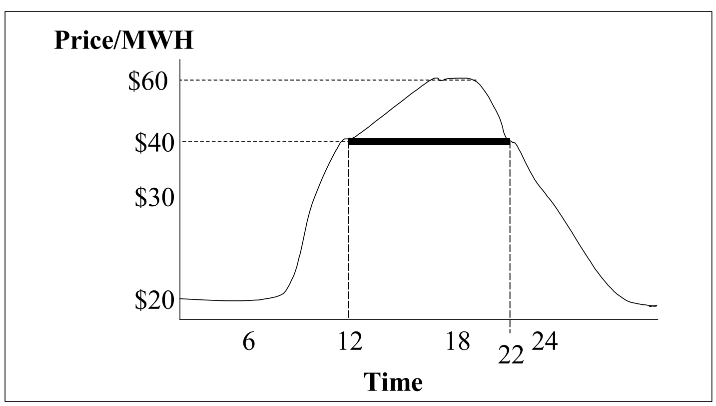
Q. Dr. Tabors states (page 16, lines 14 and 15) that, "Pumped hydro is an example of a generation technology whose value is based entirely on the opportunity value of the water that is being pumped 'up hill'." Is this not correct?

A. Dr. Tabors’ statement is not correct and violates basic economic principles discussed earlier in this testimony. The value of the electricity produced by a pumped hydro unit is the value of the electricity that is displaced. Pumped hydro electricity is generated by pumping water uphill, usually at an off-peak hour, and then generating electricity by letting the water run back downhill. Once the water has been pumped uphill, the cost of doing so becomes a "sunk" cost. The question before the operator of the pumped storage facility, once he has filled his pond at the top of the hill, is when to let the water run downhill so that it may displace the most valuable possible electricity.

Q. Please describe how the operator makes this decision.

A. A pumped storage facility will have a certain size. Depending on the size, the full pond will be able to generate electricity for a certain period of time. If, for example, a pumped hydro pond could run an electricity hydro generator for a total of ten hours, the question for the hydro operator is to pick the ten hours of the day during which he expects the market clearing price will be the highest. He will then run his hydro plant for those ten hours and the value of the electricity generated will be the value of the energy displaced. We illustrate this in Diagram 3.

Diagram 3
10 Hours of Pumped Storage Would Be Dispatched to
Maximize the Value of the Displaced Energy



Q. Please explain your Diagram 3.

A. Diagram 3 shows a hypothetical representation of the market clearing price of electricity over a 24-hour period. As can be seen, during off-peak, night hours, the electricity is relatively cheap. In the morning, as load on the system increases, the market price (reflecting the marginal cost of the load following plant) increases, reaches a peak and then decreases as load decreases until it reaches its low nighttime, off-peak price once again. In Diagram 3, we have represented the dispatch decision of a hypothetical operator who has a 10 MW pumped storage unit that can run for a total of ten hours. The operator will make an estimate of the prices that he expects to see the next day. If he expects to see the pattern that we have drawn in the exhibit, he will schedule his pumped storage to run for the ten hours between 12:00 noon and 10:00 p.m. The value of the electricity generated by the pumped storage facility is the value of the electricity that is displaced by his generation. This is 10 MW of power times the market clearing price over the ten hours.

Thus, the historic cost of pumping does not enter into the pumped hydro operator's decision process. (The prospective pumping cost will enter into the pumping decision.) It should also be clear that the operation of the pumped storage unit does not, and cannot, set the market clearing price.

8. The Units That Dr. Tabors Recommends To Set the MMCP Are Not Load-Following Units

Q. For the purposes of calculating an MMCP, does Dr. Tabors select units that were "…dispatched each hour in the real-time imbalance market…?" Page 33, July 25 Order.

A. No. Dr. Tabors, on page 5 beginning on line 13, disregards the method established by the Commission and develops his own criteria for determining "the last unit dispatched." He suggests that the choice is either between the method explicitly described by the Commission "…or by simply identifying the participating in-state unit with the highest heat rate or highest cost." Lines 15-17. Dr. Tabors, at the beginning of page 6, states that the universe for choosing the plant to set the new MMCP, "…should include all units in the CA ISO markets that will be subject to refund under the Commission's orders, based on the retrospective application of the MMCP. This includes those units in the BEEP stack, out-of-sequence ("OOS") and out-of-market ("OOM" excluding balance of the month transactions) purchases (the Imbalance market), as well as units in the CA PX, i.e. all the units in the real-time or spot market…." Thus, Dr. Tabors, and his colleague Dr. Cardell, have produced estimates for an MMCP based on plants that are not actual units dispatched in the real-time imbalance market, and are plants that could not be marginal in the sense that they would be used to follow load and therefore could not be the plants setting a market clearing price in a competitive market.

Q. Does Dr. Tabors recognize that pumped storage units do not follow load?

A. Yes. On page 16, lines 15-18, Dr. Tabors describes the "highly systematic fashion" by which pumped storage operators dispatch pumped storage units. In his description he indicates that, "These decisions for pumped hydro occur on a daily or weekly basis." Clearly, a unit that is scheduled on a weekly basis is not operating to follow load.

C. The MMCP Also Serves as a Price Cap for Ancillary Services

Q. On page 70, lines 14-18, of his testimony, Professor Cicchetti states that, ". . .the CAISO is seeking refunds for products that are more properly characterized as capacity or options, as opposed to energy. These include Spinning Reserves, Non-Spinning Reserves, and Replacement. The MMCP calculated by the CAISO, once correctly calculated, should not be applied to these capacity markets." Do you agree?

A. No. Again, this is an issue where the Commission has spoken, clearly indicating that refunds have been ordered for ancillary services. To the extent there remains any question, the position taken by the Commission and the CAISO that ancillary services prices would not have gone to the levels they did in a competitive market is consistent with economic theory. Ancillary services can be viewed as a type of option; and the value of this option, and what the provider of ancillary services gets paid, varies directly with the market clearing price of energy and should never be higher than the price of energy. The Commission correctly capped ancillary services prices at the relevant hourly market clearing price (i.e., the lower of the actual market clearing price or the calculated MMCP). December 19 Order at 62,203. For example, in an efficient competitive market, the price for providing spinning reserve will have to equal the opportunity cost to the generator of not selling energy. This means that the market price of spinning reserve will be equal to the market price of energy minus the cost that is avoided by providing spin instead of energy. This is the opportunity cost of providing the spinning reserve instead of providing energy to the balancing market.

IV. SELLERS' WITNESSES EMPLOY ARGUMENTS THAT GO BEYOND FACTUAL ISSUES

Q. In addition to errors in economic theory and analysis and the improper interpretation of the Commission's July 25 Order, what other arguments do the SELLERS' witnesses rely upon in their testimony?

A. The SELLERS' witnesses have also relied upon:

1) a direct threat of retribution, and

2) the specter of irrevocable harm.

1. The Threat of Retribution

Q. Is there a threat of retribution in Dr. Jones' claim (page 21, lines 1-3) that "Certain companies … may elect to increase prices of supplies offered to the marketplace" as a consequence of economic harm that could allegedly occur if the CAISO's interpretation of the Commission's Order were adopted?

A. Yes, it is an unconscionable threat to this Commission and the people and economy of the State of California The economic interpretation of this statement is that if the Commission develops a method that some sellers do not like, that they will penalize customers by exercising market power and increasing prices. Dr. Jones' statement is both an admission of market power and a threat that market power will be exercised as a form of retribution.

2. Irrevocable Harm

Q. Dr. Jones, at page 8, lines 3 and 4, states that, "If expected (seller) revenues are inadequate to cover their costs, because of the "heat rate issue," sellers will be irrevocably harmed." Have the California parties sought to irrevocably harm any seller or any other market participant that might be liable for a refund?

A. No. The California parties have generally argued[17] for a cost-of-service based resolution of the unjust and unreasonable prices charged by sellers. This cost-of-service approach has the feature of ensuring that no seller would be harmed. SELLERS have rejected such an approach. Moreover, the Commission has guaranteed that all sellers will recover at least their costs, including a reasonable return, by providing sellers with the option of seeking cost-of-service rates for their portfolio operating in the west as an alternative to the results of the refund case. It would appear that the Sellers are not worried about whether they have recovered their actual costs and are instead simply attempting to maximize their above-cost returns.

Q. Do you agree with Dr. Jones' concern for "additional compensation" on page 7, line 8?

A. No. Dr. Jones seeks compensation for damages without demonstrating the harm that he has alleged. Dr. Jones, as well as the other witnesses that parrot his concern for inadequate compensation resulting from the CAISO's estimates, have had the opportunity to demonstrate to this tribunal that the harm that they theorize is real, and not theoretical. They have chosen not to do so.

Q. Does this conclude your testimony?

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[17] Request for Rehearing of the California Electricity Oversight Board of the April 26, 2001 Order, Docket Nos. EL00-95-031, et al. (May 25, 2001); Request for Rehearing of the Public Utilities Commission of the State of California, Docket Nos. EL00-95-031, et al. (May 25, 2001); Request for Rehearing by the California Electricity Oversight Board of the June 19, 2001 Order, Docket Nos. EL00-95-039, et al. (July 18, 2001); Request for Rehearing of the People of the State of California *ex rel.* Bill Lockyer, Docket Nos. EL00-95-039, et al. (July 19, 2001); California Parties' Request for Rehearing of the Commission's Order Establishing Evidentiary Hearing Procedures, Docket Nos. EL00-95-046 (August 24, 2001).

A. Yes.

ATTACHMENT A

Expert Witness Qualifications

For

Carl Pechman

CARL PECHMAN

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EDUCATION

Ph.D. Resource Economics, CORNELL UNIVERSITY, 1990.

Dissertation: *Reliability and Power: The Role of Regulation in the Transformation of Markets for Electric Generation*

M.S. Applied Econometrics and Quantitative Analysis, CORNELL UNIVERSITY, 1983.

Thesis: *The Impact on Ratepayers of Converting Generating Units from Oil to Coal Burning in New York State*

B.S. Biology, CORNELL UNIVERSITY, 1976.

PRESENT EMPLOYMENT

Power Economics, Inc., 1999 - present

President

- Founder of 'virtual consulting" firm with nine Ph.D. economists and electrical engineers providing consulting and strategic advice to a broad array of clients navigating the move to competition in the electric power industry.
- Currently serving as principal economic adviser to the California State Assembly in connection with efforts to resolve the California "electricity crisis." Activities include: testimony to the Federal Energy Regulatory Commission on market price mitigation, analysis of power contracts, strategies for selling thirteen billion dollar municipal bond to repay state budget for dollars spent to purchase power, strategies to resolve PG&E bankruptcy and return Southern California Edison to financial health, re-structuring of wholesale power markets and development of legislation.
- Witness for California Parties before the Federal Energy Regulatory Commission on issues related to market design, market power mitigation and refunds.
- Electric price forecasting.
- Comparative analysis of the design and operation of competitive power markets (for the Electric Power Research Institute).
- Strategic analysis of power marketer entry into the New York retail electricity market.
- Design of demand response programs.
- Analysis of utility revenue requirements, finance and rates.
- Analysis of installed capacity (ICAP) markets.

- Design of market monitoring and mitigation.
- Design of standby and back-up rates.
- Rate design for Internet Data Centers.
- Training large customers to purchase power in competitive markets.
- White paper for BOMA California on the effect of California electricity crisis on commercial real estate, with recommendations for resolving the crisis.
- Advice on sale of software technology that provided the basis for developing Adobe Atmosphere.
- Expert testimony:

Power Refunds

Declaration for California Parties before the Federal Energy Regulatory Commission (Dockets EL00-95-004, EL00-95-005, EL00-95-019, EL00-95-031, EL00-98-004, EL00-98-005, EL00-98-018, EL00-98-030, EL01-10-000, EL01-10-001)

Market power mitigation

Affidavit for the California Assembly before the Federal Energy Regulatory Commission (Dockets No. EL00-95-012, No. EL00-98-000, No. RT01-85-000, No. EL01-68-000)

Asset valuation

Before the California Public Utilities Commission -- Application of Pacific Gas and Electric Company to Market Value Hydroelectric Generating Plants and Related Assets Pursuant to Public Utilities Code Sections 367(b) and 851 (testimony and cross-examination).

Utility cost analysis and rate design

Before the New York Public Service Commission Case # 00-E-1208 - Proceeding on Motion of the Commission in the Matter of Consolidated Edison Company of New York, Inc.'s Plans for Electric Rate Restructuring with Respect to Service Provided in Westchester County.

Before the New York Public Service Commission Case 99-S-1621 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Steam Service (testimony submitted).

Power contract litigation

Hydrocarbon Generation, Inc. and Allegany Limited Partnership v. Niagara Mohawk Power Corporation, Before the Superior Court of the State of New York, Cattaraugus County (deposition).

Commercial contract litigation

Doyle and Schmidt v. Corbin, Before the Superior Court of the State of California in the County of Monterey (jury trial).

PROFESSIONAL EXPERIENCE

LECG, INC., 1997-1999

Director

- Wholesale electric market design.
- Economic analysis of electric system reliability.
- Regulatory treatment of distribution companies.
- White paper prepared for the Edison Electric Institute on Codes of Conduct.
- Strategic assessment of power marketing opportunities.
- Comparative analysis of electric utility competitive strategies.
- Commercial consulting on competitive opportunities.
- Expert testimony:

Power contracts and damages

Norcon Power Partners v. Niagara Mohawk Power Corporation, Before the United States District Court for the Southern District. Testimony and deposition.

Coachella Valley Water District v. Imperial Irrigation District, Before the Superior Court of the State of California, County of San Bernadino. Deposition.

Cost unbundling

In the matter of the application of and complaint by Residential Electric, Incorporated, vs. Public Service Company of New Mexico, Case No. 2867. And in the matter of the application of Residential Electric, Inc. for a Certificate of Public Convenience and Necessity, Case No. 2868. Before the New Mexico Public Utility Commission.

NEW YORK STATE PUBLIC SERVICE COMMISSION, 1979-1997

Supervisor of Energy and Environmental Economics.

Successive promotions to positions of increasing responsibility.
Extensive analysis, testimony and complex management experience.

Expert testimony

- Testimony provided in over forty proceedings – described below – before the New York Public Service Commission, New York State Energy Planning Board, the New York State Board on Electric Generation Siting and the Environment, and the New York Department of Environmental Conservation.

Market Power

- *System design and market power:* Evaluated impact of wholesale electric system design on ability to exercise market power.
- *State action doctrine*: Reassessment of the State Action Doctrine in the light of competition.
- *Prudence of anti-competitive actions*: Regulatory treatment of revenues and costs associated with anti-competitive actions.

Electric Market Transformation

- *ISO Development*: Co-lead in regulatory process to design an Independent System Operator and Power Exchange for New York State. Departmental mediator in a multi-party process that resulted in an April, 1996 collaborative report on the development of the ISO. Departmental representative in negotiations with utilities. Coordinated and participated in the technical review of proposals.
- *Price Caps*: Developed price cap proposals.

Electricity Economics

- *Avoided Costs*: Developed, through negotiated and litigated proceedings, the methodology used for calculating avoided costs.

- *Cost studies and Pricing*: Preparation of marginal cost studies, analysis of electric system reliability, with emphasis on the relationship between planning concepts, costs and rate design.
- *Nuclear Power*: Economics and rate treatment of nuclear power plants.
- *Wheeling*: Task force leader in wheeling cost case that investigated alternative methodologies for calculating wheeling costs.
- *Power Pool Audit*: Economist assigned to audit of the New York Power Pool. Review of planning, pricing, and operations.
- *Energy Conservation*: Economic analysis of energy conservation options and regulatory impediments to the adoption of conservation.
- *Production Cost Modeling*: Supervised agency use of PROMOD.

Energy Planning and Siting

- *State Energy Plan*: Preparation of policy papers, analysis and testimony in State Energy Master Planning Process.
- *Analysis of Need*: Principal staff witness on the economics of "need" for energy-related facilities, including coal-fired power plants, electric transmission lines and natural gas pipelines.
- *Coal Conversion*: Department's witness on the economics of re-converting coal capable oil-fired generating units to coal burning.

Environmental Economics and Policy

- *Externalities*: Member of the Keystone Dialogue on Utility Planning using Least-Cost Principles, addressing the use of externalities in the regulatory process.
- *Energy and Environmental Modeling*: Project manager for Cornell-Carnegie Mellon Universities Model, a successor to the Advanced Utility Simulation Model.
- *CAAA*: Analysis of utility compliance to the Clean Air Act Amendments of 1990.
- *Resource Use*: Economics of multi-use resources, such as balancing interests of lake level regulation for the Great Sacandaga Reservoir.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, 1991-1994.

Consultant

- Assisted Mosenergo, the Moscow electric utility, prepare a business plan for the transformation from a planned to a market economy.

URBAN SYSTEMS RESEARCH AND ENGINEERING, 1979

Environmental Economist

- Contract research to the US Council on Environmental Quality, Environmental Protection Agency, and Department of Energy.
- Analysis of energy and environmental interactions, the structure of the Mid-Atlantic fishing industry and industry response to sewer surcharges.

PUBLICATIONS AND POLICY PAPERS

1) "The California Electricity Crisis: A Report To the Building Owners And Managers Association (BOMA) of California," With Miles Bidwell, prepared for BOMA California, March 19, 2001.
2) "A Demand Response Will Lower Peak Prices," with Miles Bidwell, Duane Chapman, Tim Mount, prepared for Multiple Interveners for presentation to the New York Independent System Operator, January 18, 2001.
3) "Retail Competition in New York: A Status Report," Prepared for Utility.com, September 26, 2000
4) "Developing Codes of Conduct: An Analysis of Parties and Positions," with Robert G. Harris. Prepared for and published by Edison Electric Institute, January, 1999.
5) *Regulating Power: The Economics of Electricity in the Information Age*, Kluwer Academic Publishers, 1993.
6) "Exporting Integrated Resource Planning to Less-Developed and Post-Communist Countries," with Marc Ledbetter, David Wolcott and Mark Cherniack, *Proceedings ACEEE Study on Energy Efficiency in Buildings, Integrated Resource Planning volume*, 1992.
7) *Report on the Management & Operations Audit of the New York Power Pool*, with fellow staff, New York State Department of Public Service, August 1991.
8) "Determining the Value of Electricity from Waste-to-Energy Facilities: A Comparison of Pricing Based Upon Avoided Costs and Bidding," *Proceedings: Fifth Annual Conference on Solid Waste Management and Materials Policy*, January 1989.
9) "The Regulator as Mediator/Negotiator," *Proceedings: National Association of Regulatory Utility Commissioners (NARUC) Sixth Biennial Regulatory Information Conference*, September 1988.
10) "Equity, Efficiency, and Sulfur Emission Reductions," *Public Utility Fortnightly*, May 16, 1985 (paper originally presented at the 1984 Air Pollution Control Association Annual Meeting).
11) "The Role of Public Utility Commissions in Evaluating Sulfur Emission Reduction Strategies," with William Deehan, *Proceedings: NARUC Fourth Biennial Regulatory Information Conference*, September 1984.

12) "Converting Oil Fired Generating Units to Coal in New York State," with Jack Lebowitz, *Northeastern Environmental Science*, vol. 1, no. 2, 1982.
13) "REVREQCON: A Model for Evaluating the Revenue Requirement of Coal Conversion Expenditures," with Charles Dickson, *Electric Ratemaking*, vol. 1, no. 3, June 1982.

PRESENTATIONS

1) "The Energy Crisis & Commercial Real Estate: Winning Lower Prices and Increased Reliability." Building Owners and Managers Association's National Advisory Council Spring Conference. San Francisco. March 2001.
2) "The Rationale for Market-based Customer Curtailment" presented at Price-Responsive Load Management: A New Opportunity in New York State Electricity Markets, sponsored by the New York Independent System Operator and the New York State Energy Research and Development Authority. Albany, NY. March 2001.
3) "The California Experience – Coming to a Busbar Near You?" Presented at Multiple Intervenors' Annual Meeting. Syracuse, New York. October 19-20, 2000.
4) "The Economics of Distribution Competition," presented at Competitive Challenge in Network Industries, The 13th Annual Western Conference of the Advanced Workshop in Regulation and Public Utility Economics, sponsored by Rutgers University, Graduate School of Management Center for Research in Regulated Industries, July 2000.
5) "The Changing Role of Regulation in Competitive Electric Markets," presented at the Independent Power Producers of New York. 13th Annual Spring Legislative Conference. Albany, New York. May, 1999.
6) "The Importance of Transaction Design in Divestiture," presented at Generation Asset Divestiture: Case Studies of Decisions, Valuations and Transactions, sponsored by AIC Conferences; Boston, MA, September 17-18, 1997.
7) "Reflecting the Value of Reliability in a Competitive Market," presented at Reliability for Competitive Power, co-sponsored by IBC Group and EPRI, San Francisco, CA, September 29-30, 1997.
8) "New York's Electric Power Restructuring and the Treatment of Nuclear Power," presented at Nuclear Power in the Competitive Era, sponsored by InfoCast; Washington, DC, January 1997.
9) "The Nuts and Bolts of Retail Access," presented at Multiple Intervenor's Conference; Albany, New York, May 23, 1996.
10) "The Regulator and Anti-Competitive Behavior," presented at the Eighth Annual Western Conference of the Advanced Workshop in Regulation and Public Utility Economics, sponsored by Rutgers University, Graduate School of Management Center for Research in Regulated Industries, July 1995.

11) "Retail Competition in New York's Electric Power Market," presented at Competitive Power Sourcing for Industrial Customers, sponsored by InfoCast; Chicago, March 1995.
12) "Environmental Implications of Electric Market Transformation," presented at New York State Network for Economic Research, Research-in-Progress Conference, December 1994.
13) "The Role of Information as a Marketing Tool in the Competitive Environment," presented at Marketing for Electric Utilities, sponsored by AIC Conferences; Washington, DC, October 1994.
14) "State Regulatory Perspectives on Emissions Trading," presented at SO_2 Emissions Trading in the Electric Utility Sector, sponsored by The Risk Management and Decision Process Center, The Wharton School and Philadelphia Electric Company; Philadelphia, Pennsylvania, October 1993.
15) "Competition and the Role of Regulators," presented at Keeping the Competitive Edge, sponsored by the Independent Power Producers of New York; Albany, New York, October 1993.
16) "The Customer's Role in Integrated Resource Planning," presented at PQL –Partners in Quality Leadership, sponsored by Praxair, Inc.; Buffalo, New York, October 1993.
17) "The Evolution of Integrated Resource Planning: Incorporating Environmental Externalities," invited paper presented at the Third USSR/US Bilateral Conference on the Use of Economic Instruments in Environmental Protection; Moscow, USSR, October 1991.
18) "The Economics of Environmental Dispatch," presented at Rutgers University Advanced Workshop in Regulation and Public Policy Economics, February 1991. Also presented at the conference DSM and the Global Environment, sponsored by the US Environmental Protection Agency, The Edison Electric Institute, and the New York State Energy Research and Development Authority; Arlington, VA, April 1991.
19) "Model Access and Administratively Determined Prices," presented at the Eighth Annual Conference of the Rutgers University Advanced Workshop in Regulation and Public Utility Economics; Newport, Rhode Island, May 1989.
20) "Information Cartelization and the Control of Regulation," presented at the Allied Social Science Association Annual Meeting, December 1988.
21) "Electric Capacity Planning in New York: Model Limited Choice and Inefficient Investment in Reliability," presented at the Sixth Annual Conference, Rutgers University Advanced Workshop in Regulation and Public Utility Economics, May 1987.
22) "Using Production Costing Models to Estimate PURPA Buyback Rates: The New York Experience," National Association of Regulatory Utility Commissioners (NARUC) Fifth Biennial Regulatory Information Conference, September 1986.
23) "Estimating Long Run Avoided Costs for New York State Electric Utilities," Fourth Annual Conference, Rutgers University Advanced Workshop in Public Utility Economics and Regulation, May 1985.
24) "The Future of Energy Imports to the Northeastern United States," presented at the Corpus Energy Group – Energy Pricing Conference; Toronto, Canada, October 1983.

25) "An Estimate of the Capacity Cost of the Shoreham Nuclear Power Plant," presented at the American Association for the Advancement of Science Annual Meeting, May 1983.

ATTACHMENT B

Expert Witness Qualifications

For

Miles O. Bidwell

MILES O. BIDWELL, JR., PH.D.

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Dr. Bidwell is a Principal of Power Economics, Inc. Power Economics provides advice and expert testimony on matters pertaining to the electricity industry, its regulation, and its movement toward a more competitive and efficient industry structure. Dr. Bidwell holds B.A., M.A. and Ph.D. degrees in Economics from Columbia University, where he specialized in applied microeconomic theory and econometrics.

Until 1996, Dr. Bidwell was a Vice President of National Economic Research Associates, Inc. (NERA). At NERA, Dr. Bidwell directed projects, conducted studies and presented testimony on behalf of Independent Power Producers of electricity, of electric, gas and telephone utilities and on behalf of the customers of regulated utilities. He also performed market and cost studies in antitrust and merger cases and frequently advised clients on topics such as analyzing the implications of different industrial structures and alternative forms of regulation. For the last twenty years, Dr. Bidwell has been conducting research and advising clients on issues related to the electricity industry's transformation from regulation to competition. He was an early proponent of the market type structure that became the basis for the electricity industry in England and Wales, worked on a new industry structure in California (not the one adopted), and participated in each of the industry restructuring proceedings in New York State. As part of his more recent work in England, he developed a method for including demand side bidding in a day ahead and spot electricity market. Since 1999, he has been working with economists at Power Economics, Inc. on cases and reports in New York and California.

Before joining NERA, Dr. Bidwell served as Chief of Regulatory Research for the New York Public Service Commission. During this period he was responsible for the further application of economic theory to regulation and to ratemaking involving the areas of electric utilities, telecommunications, water and gas, including developing a method for using NYPP data to estimate the time varying marginal cost of electricity. At the same time, Dr. Bidwell designed and directed the graduate Program in Regulatory Economics at the State University of New York at Albany, where he was an adjunct professor. Earlier in his career, he served on the economics faculty at Wake Forest University.

As an expert witness, Dr. Bidwell has appeared before Federal and State courts and in hearings before numerous State regulatory Commissions, the U.S. Nuclear Regulatory Commission, the Federal Energy Regulatory Commission, the Federal Communications Commission, and the House of Lords.

EDUCATION

COLUMBIA UNIVERSITY

Ph.D. Economics, 1973

COLUMBIA UNIVERSITY

M.A. Economics, 1969

COLUMBIA UNIVERSITY

B.A. Economics, 1966 (with honors)

EMPLOYMENT

1999 POWER ECONOMICS, INC.

Principal. Dr. Bidwell has worked with Dr. Pechman for more than 20 years. Since 1999, Dr. Bidwell has focused on projects that he could do in collaboration with the economists at Power Economics.

BIDWELL ASSOCIATES, INC.

1996- President. At Bidwell Associates, Inc., Dr. Bidwell provides advice and expert testimony on matters pertaining to the electricity industry, its regulation, and its movement toward a more competitive industry structure.

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.

1985-1996 Vice President. At NERA, Dr. Bidwell directed projects, conducted studies and presented testimony on behalf of Independent Power Producers, electric and telephone utilities and on behalf of customers of regulated utilities. He performed market and cost studies in merger and antitrust cases and advised clients on issues pertaining to the privatization and alternative industrial structures in the US and in the UK.

NEW YORK STATE PUBLIC SERVICE COMMISSION.

1978-1985 Chief of Regulatory Research. During his more than seven years on the staff of the New York State Public Service Commission, Dr. Bidwell developed methods for measuring and analyzing economic costs and marginal costs, which are now used in rate setting. He has been responsible for the further application of economic theory to regulation and to ratemaking involving the areas of electric utilities, telecommunications, water and gas.

STATE UNIVERSITY OF NEW YORK AT ALBANY

1981-1985 Adjunct Professor. Dr. Bidwell designed, and directed the Graduate Program in Regulatory Economics at the State University of New York at Albany where he was an Adjunct Professor of Economics.

WAKE FOREST UNIVERSITY

1973-1978 Assistant Professor. Dr. Bidwell taught courses in microeconomic theory, economic growth and development, international trade, and industrial organization.

COLUMBIA UNIVERSITY

1970-1973 Preceptor in Economics

PROFESSIONAL ACTIVITIES

The American Economic Association

The Royal Economic Society

The American Bar Association

SELECTED SPEECHES

"Using Marginal Costs in Electric Rate Design." Presented at the Second NARUC Biennial Regulatory Information Conference, Ohio State University, Columbus, Ohio, September 1980.

"Optimal Rate Structure: An Empirical Examination." Presented at the Workshop on Regulatory Economics, Rutgers University, Newark, New Jersey, March 1981.

"Efficiency and Equity of Kilowatt and Kilowatt Hour Charges: An Empirical Examination." Presented at the Annual Conference of the Advanced Workshop in Regulation and Public Utility Economics, Mohonk Mountain House, New Paltz, New York, June 3-4, 1982.

"Deriving an Appropriate Capital Carrying Charge in a Time of Inflation." Presented at the Third NARUC Biennial Regulatory Information Conference, Ohio State University, Columbus, Ohio, September 1982.

"Efficient Pricing for Cogenerators: Marginal Energy Cost and Power Pool Contracts." *Proceedings of the Third NARUC Biennial Regulatory Information Conference*, with Mark Reeder, Ohio State University, Ohio, September 1982.

"Marginal Cost Analysis and Rate Base Allocation Under Suboptimal Inflationary Conditions." Presented at the 1983 Rate Symposium on Problems of Regulated Industries, Kansas City, Missouri, February 6-9, 1983.

"Optimal Prices, Economic Depreciation, and Regulated Utilities." Presented at the 23rd Annual Iowa State Regulatory Conference, Ames, Iowa, May 1984.

"Avoiding Rate Shock: The Search for Optimal Intertemporal Cost Allocation." Presented at the Institute of Public Utilities Fifteenth Annual Conference, 1984.

"Regulatory Guidelines for Pricing Electricity in Times of Excess Capacity." Presented at the Michigan State University Public Utility Papers, 1985.

"The Significance of Economic Depreciation for the Future Viability of the Bell Operating Companies." Talk given at the Touche Ross Conference on

Capital Recovery in Telecommunications, Washington, D.C. October 24-25, 1985.

"Indexing Electric Utility Rates." Presented at the February 18-19, 1987, Energy Research Group Meeting.

"Depreciation Policy in a Competitive Environment." Presented at a conference sponsored by NERA at Camelback Inn, Scottsdale, Arizona, March 4-7, 1987.

"U.S. Economic Regulation of Electricity." Presented in London, England, June 26, 1987.

"Equity Versus Efficiency." Presented at Innovative Pricing Conference, Syracuse, New York, September, 1988.

"Marginal Cost and Bad Fish." Presented at the conference of Industrial Energy Bulletin, New York, New York, 1989.

"From Revenue Requirements To Rates: An Economist's Perspective." Continuing Education Lecture sponsored by the Ohio Bar Association, May 15, 1989.

"Regulatory Scrutiny of Marketing Expenses: Competitive Necessity vs. Regulatory Hang Ups." Presented at NERA Telecommunications Seminar, Scottsdale, Arizona, April 12-14, 1989.

"Are New York's Demand Side Management Programs Economic?" Presented at the Multiple Intervenors' Annual Meeting, Syracuse, November 1-2, 1989.

"Measuring The Value Of Unserved Energy." Presented at the March 13-14, 1990, Energy Research Group Meeting in Washington, D.C.

"Price Discrimination Is Not Hazardous To Your Health." Presented at the Conference on "Problems of Mixed Competitive and Regulated Markets: The Issue Of Undue Price Discrimination" in Windsor, England, May 19, 1990.

"Estimating Customer Preferences." Presented at NERA, U.K., May 21, 1990.

"The Value of Unserved Energy—Revealed." Presented at the June 26-27, 1990 Energy Research Group Meeting in Washington, D.C.

"An Analysis of New Rate Design Techniques." Presented at the Multiple Intervenors' 1990 Annual Meeting, Syracuse, New York.

"The Value of Reliability and Least Cost Planning." Presented at the 1991 Electric Utility Business Environment Conference & Exhibition, Denver, CO, March 20-22, 1991.

"Measuring the Value of Reliability." Presented at the 1991 Marginal Cost Working Group Seminar, Seattle, WA, April 25, 1991.

"Less is More." Presented at the 1991 Annual Multiple Intervenors' Meeting in Syracuse, New York, October 30, 1991.

"Accurate Depreciation Rates And Rapid Amortization Benefit Customers (Or Everything You Always Wanted To Know About Depreciation But Were Afraid To Ask)." Presented at the Minnesota Public Utilities Commission, March 9, 1992.

"Is Environmentalism Good for Business?" A talk at the Economic Recovery & Environmental Responsibility Conference. Presented by Sound Waters & SACIA, The Southwestern Area Commerce & Industry Association, May 13, 1992.

"Green Economics." A speech presented at the Green & Clean 6th Annual Corporate Breakfast Forum, Greenwich, Connecticut, October 28, 1992.

"Opportunities and Challenges in Privatization." A talk presented at the 2nd Annual European Business Conference, Chicago, IL, May 1, 1993.

"Rockets & Feathers: The Asymmetry of Response to Telephone Price Change." Presented at the Advanced Workshop in Regulation and Public Utility Economics Twelfth Annual Conference, Cape Cod, Massachusetts, May 26-28, 1993.

"Opening the Flood Gates of Competition—Industrial Customers and Independent Power Producers' Stake in Competitive Electricity Supply." Presented at the IPPNY Annual Membership Meeting and Conference, Albany, October 6, 1993.

"Issues In Incentive Regulation: Theory Versus Practice." Presented at the Rutgers Research Seminar, "Incentive Regulation for Public Utilities," in Newark, New Jersey, October 22, 1993.

"Retail Wheeling and the Future US Electricity Industry." Presented at the National Independent Energy Producers Winter Quarterly Meeting, in Washington, DC, January 25, 1994.

"Measuring the Value of Unserved Energy." Presented at the Advanced Workshop in Regulation and Public Utility Economics at Rutgers University in Newark, New Jersey, April 15, 1994.

"Restructuring the Electricity Industry." Presented at "Markets in Motion." Independent Power Producers of New York's Annual Spring Legislative Conference in Albany, May 18, 1994.

"Rockets & Feathers II: Empirical Estimation of Asymmetric Response and Reconciliation of Asymmetric Behavior with Classical Utility Theory." Presented at the Advanced Workshop in Regulation and Public Utility Economics Thirteenth Annual Conference, Newport, Rhode Island, May 25-27, 1994.

“International Lessons for Electricity Restructuring.” Presented to the Economic Planning Institute, Government of Japan, Tokyo, Japan, March 1995.

“Reduce Stranded Cost – Restructure Rates.” Presented before Parties to the New York Public Service Commission Competitive Opportunities Docket, Albany, New York, May 3, 1995.

“Rules For A Speedy And (Less) Painful Transformation To Competition,” presented at the Advanced Workshop in Regulation and Public Utility Economics 14th Annual Conference, Newport, Rhode Island, May 26, 1995.

“Accommodation of the System to IPPs with Open Access.” Presented at the III Workshop on Independent Power Production in Brazil, Belo Horizonte, Brazil, June 30, 1995.

“Promoting Electricity Consumption to Ease the Transition into Competition.” Presented at the 107th Annual Convention, Regulatory, Symposium, National Association of Regulatory Utility Commissioners, New Orleans, Louisiana, November 13, 1995.

“Stranded Costs: There is a Solution.” Presented at the Rutgers University Advanced Workshop in Regulation and Public Utility Economics, Newark, New Jersey, November 17, 1995.

"Update on Electricity Restructuring Across the Northeast." Presented at the New Jersey Business & Industry Association, Business to Business Seminar, *Shrinking Your Electric Bill: How Your Business Can Save Money on Electric Bills*, Jamesburg, New Jersey, December 12, 1995.

"How to Minimize Stranded Costs Through Rate Restructuring." Presented before a conference of the Parties to the New York Public Service Commission, Competitive Opportunities Docket, Albany, New York, February 14, 1996.

"Structuring Markets--Finding the Optimal Amount of Regulation." Presented at the Rutgers Research Seminar, *Pricing and Regulatory Innovations Under Increasing Competition,* in Newark, New Jersey, May 3, 1996.

"Market Clearing Prices on Peak Days," with Mark Reeder, presented at the Advanced Workshop in Regulation and Public Utility Economics, 15^{th} Annual Conference, Lake George, New York, May 30, 1996.

"Market Power Issues." Presented at the Independent Power Producers of New York's 11^{th} Annual Fall Conference, Albany, New York, September 25, 1996.

"Norway and England Have Very Different Electricity Market Structures: We Can Learn From Both." Presented at the 1996 Multiple Intervenors Annual Membership Meeting, Syracuse, New York, October 1996.

"Creating New Markets: The Role of ISO's, Power Exchanges, and Reliability." Presented at the Rutgers University Advanced Workshop in Regulation and Competition, Newark, New Jersey, April 1997.

"Transmission System Planning and Investment: Can a Private Market Determine and Provide the Investments That Minimize System Costs?" Presented at the IBC Group's Reliability for Competitive Power Conference, San Francisco, California, September 29-30, 1997.

"Driving on the Same Side of the Road—Avoiding Collisions on the Road to Competition." Presented at the Independent Power Producers of New York's 12^{th} Annual Fall Conference, Albany, New York, October 8, 1997.

"Marginal Cost Method for Electric Utilities." Co-taught NERA Course with Dr. Hethie Parmesano, Redondo Beach, California, October 20-22, 1997.

PUBLICATIONS AND CONSULTING REPORTS

"The Family Labor Supply Decision: A Trade Model." Ph.D. dissertation, Columbia University, 1973.

"The Price of Children and Factor Reversals." *Atlantic Economic Journal*, Vol. II, Number 2, November 1974.

"Family Structure, The Marriage Market, and Time Allocation." *Atlantic Economic Journal*, Vol. III, Number 2, November 1975.

"Comments on the Economic Impact of Damming the New River." United States Department of the Interior, Bureau of Outdoor Recreation, Washington, D.C. *Final Environmental Statement Proposed South Fork New River National Wild and Scenic River*, pages 500-503, 1976.

"Comment on Interactions Between Population and Environment." *Atlantic Economic Journal*, Vol. IV, 1976.

"A Peak Load Pricing Policy for North Carolina Utilities." *Carolina Planning*, Vol. III, Number 1, pages 16-22, Winter 1977.

"Some Thoughts on Social Responsibility and Scientists." *Spring*, Vol. I, Winston-Salem, North Carolina, November 1977.

"Efficient Pricing for Cogenerators: Marginal Energy Cost and Power Pool Contracts." *Proceedings of the Third NARUC Biennial Regulatory Information Conference*, with Mark Reeder, Ohio State University, Ohio, September 1982.

"Avoiding Rate Shock: The Search for Optimal Intertemporal Cost Allocation." *Changing Patterns in Regulation, Markets, and Technology: The Effect on Public Utility Pricing*. Proceedings of the Institute of Public Utilities Fifteenth Annual Conference, Michigan State University Public Utilities Papers, 1984, P.C. Mann and H.M. Trebing, eds., pages 481-507.

"Regulatory Guidelines for Pricing Electricity in Times of Excess Capacity." *The Impact of Deregulation and Market Forces on Public Utilities: The Future Role of Regulation*. Michigan State University Public Utility Papers, 1985, P.C. Mann and H.M. Trebing, eds., pages 455-470.

"The Shortage Cost of Electricity Supply." Report for the Long Island Lighting Company, August 1986.

"Is Shoreham's Operation Economic?" Report for the Long Island Lighting Company, 1986.

"Indexing Electric Utility Rates." Proceeding of the February 18-19, 1987, Energy Research Group Meeting.

"Depreciation Policy in a Competitive Environment." *Proceedings of NERA Seminar Telecommunications in a Competitive Environment* (March 1987).

"U.S. Economic Regulation of Electricity." Proceeding of Seminar in London, England, June 26, 1987.

"Report to Oglethorpe Power Corporation on the Optimal Generation Expansion Plan." Report to Oglethorpe Power Corporation, 1987.

"Will a Government Takeover of LILCO Save Money for Consumers: An Update." Report for the Long Island Lighting Company, 1987.

"Methods for Measuring the Costs of Service Interruptions and the Demand for Interruptible Rates." Study Proposal for Long Island Lighting Company, 1987.

"Economic Impact of a Premature Shutdown of the Vermont Yankee Nuclear Plant." Report for the Vermont Yankee Nuclear Power Corporation, May, 1988.

Report to Dayton Power & Light Company on DP&L's avoided costs and the optimal amount and pricing of cogeneration, June, 1988.

"Need For The Halfmoon Cogeneration Project." Report for Inter-Power of New York, Inc., on the economic value of and "need" for the Halfmoon Cogeneration Project, September, 1988.

"Equity Versus Efficiency," Proceeding of Innovative Pricing Conference, Syracuse, New York, September, 1988.

"Marginal Cost and Bad Fish," Proceedings of Conference, Industrial Utilities: Redefining The Relationship. *Industrial Energy Bulletin*, New York, New York 1989.

"New Directions In Telecommunications Planning" (Confidential Report) April, 1989.

"Regulatory Scrutiny of Marketing Expenses Competitive Necessity vs. Regulatory Hang Ups," proceeding of NERA Seminar *Telecommunications In A Competitive Environment,* April 1989.

"Comments on the Energy Efficiency Options Study Prepared for the Iowa State Utilities Board by Morgan Systems Corporation." Report for Iowa Electric Light & Power Company, November 16, 1989.

"Evaluating a Public Utility's Investments," *Public Utilities Fortnightly*, May 10, 1990.

"The Value of Reliability and Least Cost Planning," proceedings of *1991 Electric Utility Business Environment Conference & Exhibition*, Denver, CO, March 20-22, 1991.

"Optimal Pricing of Water," report for Long Island Water Company, March 4, 1991.

"Illuminating Externalities," Letter to the Editor, *Public Utilities Fortnightly*, April 1, 1991.

"Measuring the Value of Reliability," proceedings of *1991 Marginal Cost Working Group Seminar*, Seattle, WA, April 25, 1991.

"Public Disclosure of Bids and Bidders," report prepared for New York Telephone, June, 1991. (Confidential)

"An Overview of Public Utility Regulation in the United States," prepared for NERA London as part of a paper for the Sydney, Australia Water Board, July 1991.

"The Price Elasticity of Demand for Touchtone," a report for New York Telephone Company, July, 1991. (Confidential)

"The Privatization of Pakistan's Telephone Services: Outline of Economic Issues," prepared for the Government of Pakistan, August 13, 1991.

"The Time-Differentiated Marginal Costs of New York State Electric and Gas Corporation," prepared for New York State Electric and Gas Corporation, August 27, 1991.

"A Study of Demand for Optional New York Telephone Residence Services," prepared for New York Telephone Company and Telesector Resources Group, Inc., August, 1993

"Efficient Imputation and Transfer Pricing: Past, Present, and Future." Prepared for NYNEX Corporation, October 21, 1993.

"The Value of Unserved Energy." Prepared for the Los Angeles Department of Water and Power, April 8, 1994.

"The Indexation of Shipping Costs." Prepared for Burmah Gas Transport LTD, November 17, 1994.

"Issues In Incentive Regulation: TFP in State Regulatory Reform—Theory Versus Practice," *Incentive Regulation for Public Utilities*, pages 185-213, Michael A. Crew, Ed., Kluwer Academic Publishers, Boston, 1994.

"An Analysis of Asymmetric Demand Response to Price Changes: The Case of Local Telephone Calls," with Bruce X. Wang and J. Douglas Zona, *Journal of Regulatory Economics*, pages 285-298, Michael A. Crew, Ed., Kluwer Academic Publishers, Boston, 1995.

"How to Reduce Stranded Costs?" Prepared for Southern California Edison, April, 1995.

"Survey Of Studies On The Elasticity Of Demand For Electricity," with P. Della Valle. Prepared for Southern California Edison, August 1, 1995.

"Transmission Congestion and Pricing." Appendix to the New York Public Service Commission's Final Report on Electricity Competition, September 1995.

"Report on Preliminary Evaluation of Purchased Electricity Pass Through Cost Issue in Connection with GDRRA/MWE Litigation and Proposed Study Plan," with L. Guth, December 14, 1995

"Restructure Rates to Cut Stranded Costs," with P. Della Valle, *The Electricity Journal*, December 1995.

"Structuring Markets--Finding the Optimal Amount of Regulation," in, *Pricing and Regulatory Innovations Under Increasing Competition,* Michael A. Crew, Ed., Kluwer Academic Publishers, Boston, 1996

Report on the Electricity Industry Structure in the United States and the UK, prepared for the Queensland Electricity Reform Unit, Brisbane, Australia, August 1997.

"Reforming the Pool of England & Wales," with Alex Henney. Report for the Minister for Energy, Science & Industry and Pool Members, November 1997.

"A Demand Response Will Lower Peak Prices," with Carl Pechman, Duane Chapman, Tim Mount, prepared for Multiple Intervenors for presentation to the New York Independent System Operator, January 18, 2001.

"The California Electricity Crisis: A Report To the Building Owners And Managers Association (BOMA) of California," with Carl Pechman, prepared for BOMA California, March 19, 2001.

TESTIMONY

N.C. Utilities Commission	"Electricity Pricing." Expert witness testimony before the North Carolina Utilities Commission, Raleigh, North Carolina, December 18, 1975.
N.C. Utilities Commission	"Rebuttal Testimony to Duke Power Testimony of Forecasting Future Electricity Demand." Expert witness testimony before the North Carolina Utilities Commission, Raleigh, North Carolina, January 27, 1976.
U.S. Nuclear Regulatory Commission	"Projecting Future Demand for Electricity." Expert witness testimony before United States Nuclear Regulatory Commission hearings on the proposed Duke Power Company Perkins Station (includes original econometric analysis of electricity demand in North Carolina). Mocksville, North Carolina, April 27, 1976.
U.S. Nuclear Regulatory Commission	Additional expert testimony on econometric models and applications, United States Nuclear Regulatory Commission hearings, Mocksville, North Carolina, April 29, 1976.
N.C. Utilities Commission	"The Use of Econometrics in Forecasting Electricity Demand." Expert witness testimony presented before the North Carolina Utilities Commission in hearings on the Investigation, Analysis and Estimation of Future Growth in the Use of Electricity, Raleigh, North Carolina, January 25, 1977.

U.S. Nuclear Regulatory Commission	"The Future Demand for Electricity and the Misuse of Forecasting Methodology." Expert witness testimony presented before the United States Nuclear Regulatory Commission, Charlotte, North Carolina, March 10, 1977.
NYPSC Case 27350	New York Telephone—1978.
NYPSC Case 27344	Orange & Rockland Utilities—1979.
NYPSC Case 27215-16	Niagara Mohawk Power Corporation—1979.
NYPSC Case 27353	Consolidated Edison Company—1980.
NYPSC Case 27353	Consolidated Edison Company—1980 (Rebuttal).
NYPSC Case 27626	Central Hudson Gas & Electric Corporation—1980.
NYPSC Case 27909	Orange & Rockland Utilities—1981.
NYPSC Case 27986	Niagara Mohawk Power Corporation—1981.
NYPSC Case 27774	Long Island Lighting Company—1982.
NYPSC Case 28525	Long Island Lighting Company—Shoreham 1983.
NYPSC Case 28470	Central Hudson Gas & Electric Corporation—1983.
NYPSC Case 28598	Niagara Mohawk—Imprudence 1984.
NYPSC Case 29069	Niagara Mohawk 1985—Nine Mile II Phase In.
NYPSC Case 29433	Central Hudson Gas and Electric Corporation—1987.
NYPSC Case 29541-42	New York State Electric & Gas Corporation—1987.
NYPSC Case 29541-42	New York State Electric & Gas Corporation—1987 (Rebuttal).
NYPSC Case 29469	New York Telephone—1987 (Reply).
Minnesota PUC Docket P-421/CI-86-354	Northwestern Bell—1987 (Rebuttal).
NYPSC Case 29674-76	Rochester Gas & Electric—1987.

NYPSC Case 29674-76	Rochester Gas & Electric—1988 (Surrebuttal).
NYPSC Case 29670-71	Niagara Mohawk Power Corporation—1988 (Rebuttal).
Federal Court	Expert's Report and Deposition Testimony in the United States District Court for the Eastern District of New York, In Re: LILCO Securities Litigation, on materiality and causation, 1988.
Federal Court	Expert's Report and Deposition Testimony in the United States District Court for the Eastern District of New York, In Re: LILCO RICO litigation, on materiality, 1988.
New York State Board on Electric Generation Siting	Testimony on Certificate of Environmental Compatibility and Public Need—1988.
NYPSC Case 88-E-077	Central Hudson Gas & Electric Corporation—1988.
NYPSC Case 88-E-077	Central Hudson Gas & Electric Corporation—1988 (Rebuttal).
PSC Article VIII Application	Halfmoon Cogeneration Project—9/88.
Federal Court	Long Island Lighting Company: Testimony and Expert Report before the U.S. District Court for the Eastern District of New York, County of Suffolk v. LILCO, et al., concerning the materiality of charges against LILCO in a RICO action, November 1988.
NYPSC Case 28860	New York Telephone Company—1988
Federal Court	Long Island Lighting Company: Testimony and Expert Report before the U.S. District Court for the Eastern District of New York, Suffolk County, et. al. v. Long Island Lighting Company, et. al., concerning the expected time required for a nuclear power plant to go from fuel load to commercial operation, January, 1989.

Case No.: 88-T-132	Pursuant to Article VII of the Public Service Law, New York Public Service Commission. Testified on behalf of Empire State Pipeline before the New York Public Service Commission on "Need," competition, economically efficient rate structures and depreciation, March, 1989.
FERC, Case ER88-630-000, ER88-631-000, and ER89-38-000	New England Power Company—4/89 (Rebuttal). Testimony on the economic efficiency of marginal cost pricing of electricity. This testimony supported the first successful FERC decision allowing marginal cost pricing of wholesale electricity.
NYPSC Case 89-F-107	Central Hudson Gas & Electric Company—October 6, 1989.
NYPSC Case 89-F-107	Central Hudson Gas & Electric Company—October 19, 1989 (Additional Direct).
NYPSC Case 89-E-166	Rochester Gas & Electric Corporation on behalf of Multiple Intervenors—December 15, 1989.
Missouri Case TR-89-196	Contel of Missouri, Inc.—December 29, 1989 (Surrebuttal).
VT PSC Docket No. 5372	Central Vermont Public Service Corporation—February 8, 1990 (Rebuttal).
Iowa Docket No. RPU-89-9	Iowa Electric Light and Power Company—March 8, 1990 (Rebuttal).
NYPSC Case No. 80010	Inter-Power of New York, Incorporated—April 13, 1990 (Rebuttal).
NYPSC Case 89-E-175, 89-E-176	Orange & Rockland Utilities, Inc. on behalf of Multiple Intervenors—April 19, 1990.
NYPSC Case No. 80010	Inter-Power of New York, Incorporated—April 27, 1990 (Supplemental).

NYPSC Case No. 90-C-0191	New York Telephone Company—July 24, 1990 (Rebuttal).
NYPSC Case No. 80010	Inter-Power of New York, Incorporated—July 30, 1990 (Rebuttal).
NYPSC Case No. 90-C-0191	New York Telephone Company—August 3, 1990 (Rejoinder).
NYPSC Case 90-E-0647, 90-E-1648 & 90-G-0649	Rochester Gas & Electric Corporation on behalf of Multiple Intervenors—December 3, 1990.
NYPSC Case 90-E-0647, 90-E-1648 & 90-G-0649	Rochester Gas & Electric Corporation on behalf of Multiple Intervenors—December 3, 1990 (Rebuttal).
NYPSC Case 91-W-0505	Long Island Water Corporation—May 15, 1991 (Direct).
NYPSC Case 91-W-0505	Long Island Water Corporation—August 26, 1991 (Supplemental Direct).
NYPSC Case 91-E-0506	Central Hudson Gas & Electric Corporation on behalf of Multiple Intervenors—September 20, 1991 (Direct Testimony).
NYPSC Case 91-W-0505	Long Island Water Corporation—October 10, 1991 (Rebuttal).
NYPSC Case Nos. 91-E-0785, 91-E-0766 & 91-G-0767	Rochester Gas & Electric Corporation—December, 1991 (Rebuttal).

NYS Regulatory Filing	A section of a filing before the New York State Regulatory Commission. The section presents and explains the cost and demand models used to calculate the effects of the rate restructuring and explains why the restructuring will increase the economic welfare of New York Telephone customers—June 5, 1992
NYPSC Case Nos. 92-T-0114 & 92-T-0252	Independence Station-Clay 345kV Transmission Line Project—November 4, 1992 (Rebuttal Testimony).
NYPSC Case Nos. 92-T-0114 & 92-T-0252	Independence Station-Clay 345kV Transmission Line Project—November 4, 1992 (Additional Rebuttal Testimony).
NYPSC Case Nos. 92-E-0814 & 88-E-082	Niagara Mohawk Power Corporation Petition for Approval of Curtailment Procedures and Proceeding on Motion of the Commission to Establish Conditions Governing Curtailment Clauses in Contracts for On-site Generation—February 24, 1993 (Direct Testimony on behalf of Falcon Seaboard Power Corporation.)
NYPSC Case Nos. 92-E-0814 & 88-E-082	Niagara Mohawk Power Corporation Petition for Approval of Curtailment Procedures and Proceeding on Motion of the Commission to Establish Conditions Governing Curtailment Clauses in Contracts for On-site Generation—March 19, 1993 (Rebuttal Testimony on behalf of Falcon Seaboard Power Corporation.)
NYPSC Case Nos. 92-E-1055 & 92-G-1056	Central Hudson Gas & Electric Corporation on behalf of Multiple Intervenors—March, 1993 (Direct Testimony)
NYPSC Case Nos. 92-E-1055 & 92-G-1056	Central Hudson Gas & Electric Corporation on behalf of Multiple Intervenors—April, 1993 (Rebuttal Testimony)
NYPSC Case Nos. 92-E-1055 & 92-G-1056	Central Hudson Gas & Electric Corporation on behalf of Multiple Intervenors—April, 1993 (Additional Rebuttal Testimony)

Georgia PSC Docket No. 4451-U	Atlanta Gas Light Company—September 2, 1993 (Rebuttal Testimony)
FCC Case No. ENF-93-44	BellSouth Corporation, BellSouth Telecommunications, Inc. & BellSouth Enterprises, Inc.—November 1, 1993—Petition to Impose Conditional Grant to Create a Competitive Market, or Deny as Filed (Affidavit)
Georgia PSC Docket No. 4132-U	Atlanta Gas Light Company—December 30, 1993 (Direct Testimony)
NYPSC Case No. 94-E-0136	Sithe Independence Station—May 20, 1994—Petition for Original Certificates of Public Convenience and Necessity Under Public Service Law ¶ 68 to Provide Electric Service to Alcan Rolled Products Company and Liberty Paperboard, L.P. (Direct Testimony)
NYPSC Case No. 94-E-0136	Sithe Independence Station—June 24, 1994—Petition for Original Certificates of Public Convenience and Necessity Under Public Service Law ¶ 68 to Provide Electric Service to Alcan Rolled Products Company and Liberty Paperboard, L.P. (Rebuttal Testimony)
Vermont Public Service Board - Docket No. 5744	Green Mountain Power Corporation on behalf of International Business Machines Corporation (IBM)—August 1, 1994—Petition of Green Mountain Power Corporation for a change in rates. (Direct Testimony)
NYPSC Case Nos. 94-E-0098, 94-E-0099 and 94-G-0100	Niagara Mohawk—August 31, 1994—Regarding Competition Issues on behalf of Independent Power Producers of New York, Inc. (Direct Testimony)
NYPSC Case Nos. 94-E-0098, 94-E-0099 and 94-G-0100	Niagara Mohawk—September 21, 1994—Regarding Competition Issues on behalf of Independent Power Producers of New York, Inc. (Rebuttal Testimony).

Iowa Docket RPU-94-2	IES Industries, Inc.—December 12, 1994—Examine IES Industries' proposed price changes and explore the consequences of equalizing electricity prices throughout the IES service territory (Direct Testimony).
NYPSC Case Nos. 95-E-0673 and 95-G-0674	Rochester Gas & Electric Corporation on behalf of Multiple Intervenors—January, 1996 (Direct Testimony).
NYPSC Case Nos. 95-E-0673 and 95-G-0674	Rochester Gas & Electric Corporation on behalf of Multiple Intervenors—January, 1996 (Rebuttal Testimony).
NYPSC Case No. 95-C-0341	Pole Attachment Proceedings—Policy Issues, on behalf of Seven Investor Owned Electric Utilities—October 28th 1996.
NYPSC Case No. 95-C-0341	Pole Attachment Proceedings—Fact Issues, on behalf of Seven Investor Owned Electric Utilities—January 27th 1997.
NYPSC Case Nos. 96-E-0134 and 96-E-0135	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of the Niagara Mohawk Power Corporation for Electric Service on behalf of IPPNY—January, 1997.
State of New York Supreme Court, County of Warren	Seventeen Independent Hydro Power Producers vs. Niagara Mohawk Power Corporation re: contract issues—January 28th 1997.
NYPSC Case No. 96-E-0897	In the Matter of Consolidated Edison Company of New York, Inc.'s plans for electric rate/restructuring pursuant to Opinion No. 96-12, Direct Testimony on behalf of IPPNY and ENRON—February 12, 1997.
NYPSC Case No. 96-E-0897	

In the Matter of Consolidated Edison Company of New York, Inc.'s plans for electric rate/restructuring pursuant to Opinion No. 96-12, Direct Testimony re: the Proposed Settlement, on behalf of IPPNY and ENRON—April 8th 1997.

NYPSC Case No. 96-E-0891

In the Matter of New York State Electric & Gas Corporation's plans for electric rate/restructuring pursuant to Opinion No. 96-12. Direct testimony on behalf of IPPNY and ENRON—February 12th 1997.

NYPSC Case No. 96-E-0909

In the Matter of Central Hudson Company of New York, Inc.'s plans for electric rate/restructuring pursuant to Opinion No. 96-12. Direct testimony on behalf of IPPNY and ENRON—April 11th 1997.

NYPSC Case No 96-E-0900

In the Matter of Orange & Rockland Utilities, Inc. Direct testimony on behalf of IPPNY and ENRON. April 24th 1997.

NYPSC Case No. 96-E-0891

In the Matter of New York State Electric & Gas Corporation's plans for electric rate/restructuring pursuant to Opinion No. 96-12. Rebuttal testimony on behalf of IPPNY and ENRON—May 5th 1997.

NYPSC Case No. 96-E-0898

In the Matter of Rochester Gas and Electric Corporation plans for electric rate/restructuring pursuant to Opinion No. 96-12. Direct testimony on behalf of IPPNY and ENRON. May 6th 1997.

FERC Docket Nos. ER97-1523-000 and OA97-470-000

Direct testimony on behalf of Enron Power Marketing, Inc. in opposition to the request for market based authority by Central Hudson Gas & Electric Corp., *et al* and New York Power Pool. October 31st 1997.

NYPSC Case Nos. 94-E-0098

and 94-E-0099

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NYPSC Case No. 99-M-0631

AFFIDAVIT In the Matter of Customer Billing Arrangements on behalf of NEW YORK STATE ELECTRIC & GAS CORPORATION. April 20th 2000