Volume 2B

Testimony and Schedules of Witnesses:

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Marginal Cost Study

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STATE OF SOUTH DAKOTA

PUBLIC UTILITIES COMMISSION

In the Matter of the Application of OTTER TAIL POWER CORPORATION d/b/a OTTER TAIL POWER COMPANY For Authority to Increase Rates for Electric Utility Service in South Dakota	Docket No. EL08-____

Direct Testimony of

DR. HETHIE S. PARMESANO, PH.D.

Senior Vice President

NERA Economic Consulting

MARGINAL COST STUDY

October 31, 2008

OTP Exhibit ___

Contents

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dr. Hethie S. Parmesano, Ph.D. My business address is 777 South Figueroa Street, Suite 1950, Los Angeles, California 90017.

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

A. I am a Senior Vice President at NERA Economic Consulting ("NERA").

Q. On whose behalf are you submitting direct testimony in this proceeding?

A. I am submitting testimony on behalf of Otter Tail Power Company ("OTP" or the "Company").

Q. What was your role in the development of OTP's proposed rates?

A. OTP engaged NERA to develop, with input from OTP staff, a marginal cost study covering the period 2008-2012, applicable to service in North Dakota and South Dakota, and to provide advice on the application of the marginal cost results in developing proposed rates.

Q. What are the purposes of your direct testimony in this proceeding?

A. My direct testimony has six overall purposes:

- To describe the contribution that use of marginal cost information in rate design can make to the achievement of OTP's ratemaking objectives.
- To describe in general terms how OTP used marginal costs in its rate design process.
- To review the South Dakota Public Utilities Commission's ("Commission") past policies regarding use of the marginal costs in rate design and describe changes since those policies were set.
- To describe the methods used in the marginal cost study and summarize the results.
- To comment on the implications of the marginal cost results for OTP rates.
- To describe likely efficiency improvements from the proposed rates.

Q. Please summarize the main points of your direct testimony.

A. My testimony makes five main points:

- OTP's use of marginal cost in apportioning to individual rates the embedded-cost-based revenue requirement allocated to major customer classes, and for designing the structure of each rate, is consistent with the company's ratemaking objectives.
- The Commission in 1980 found in favor of using marginal costs in rate setting, to the extent feasible. Rates since then have been based on marginal costs and other factors. However, the many changes in the electricity sector and in the country's energy goals in recent years mean that the use of marginal cost information in rate design is more important than ever.
- OTP has used the results of a comprehensive marginal cost study that reflects its membership in the regional wholesale energy market, as well as its planning and operating practices regarding distribution and customer-related activities.
- The marginal cost study suggests that OTP could improve the efficiency and equity of its rate structures by: incorporating seasonality in all rates, eliminating declining blocks, significantly raising the energy charges in rates not currently subject to the cost of energy adjustment, introducing fixed charges that are closer to marginal customer and local facilities costs, correcting the seasonality of demand charges for Residential Demand Control service, and introducing an optional time-of-day rate for the largest customers.
- OTP's proposed rate structures are likely to improve the efficiency of its customers' consumption decisions by moving prices for marginal consumption closer to marginal cost.

Q. Are you sponsoring any attachments to your direct testimony?

A. Yes, summary sheets from the marginal cost study that NERA prepared for OTP are located in Exhibit ____(HSP-1), Schedule 1 and a copy of my curriculum vitae is attached hereto as Exhibit ___, (HSP-1) Schedule 2.

II. BACKGROUND AND QUALIFICATIONS

Q. Please describe your education and professional background.

A. My B.A. is from Colby College, where I majored in economics. I have M.A. and Ph.D. degrees in economics from Cornell University. Since 1980, I have worked for NERA, specializing in utility costing, pricing, strategic planning and regulatory reform. I have testified widely on these matters.

For more than two decades, I have taught seminars on electricity marginal costing and rate design. Attendees include staffs of utilities and regulatory commissions, as well as occasional commissioners. I have also participated regularly in the University of Florida Public Utility Research Center/World Bank International Training Program on Utility Regulation and Strategy, where I present sessions on electricity tariff design.

Since 1982, I have directed NERA's Marginal Cost Working Group, a utility group that is dedicated to improving methods for estimating and using marginal cost information in a variety of utility applications.

I have been involved in planning for and implementation of energy sector restructuring and rate reform in many jurisdictions around the world, including California, New York, Ohio, New Mexico, Maine, Illinois, Maryland, Massachusetts, Minnesota, North Dakota, Arizona, Oregon, Alberta, Ontario, British Columbia, Newfoundland and Labrador, Manitoba, India, Barbados, Brazil, Argentina, El Salvador, Mexico, Saudi Arabia, Spain, Greece, Ireland, Kenya, Cambodia, Japan and the UK.

My *curriculum vitae*, Exhibit___(HSP-1), Schedule 2, contains more details on my credentials.

Q. Have you previously testified before the Commission?

A. No.

III. RATE STRUCTURE OBJECTIVES AND ROLE OF MARGINAL COSTS

Q. What are the rate structure objectives that guide OTP's proposal in this case?

A. As described in the direct testimony of OTP witness David Prazak, OTP's rate structure proposal is designed to address the following objectives:

- Give the utility a reasonable opportunity to achieve its revenue requirement. This implies rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
- Promote efficient use of resources, conservation and use of renewables. This implies giving consumers price signals that reflect marginal costs, including seasonal differences and, where reasonably possible, time-of-day ("TOD") differences.

- Change rate designs gradually if necessary to avoid large bill impacts.
- Use rate structures that are reasonable and nondiscriminatory. This includes minimizing cross-subsidies within rate classes.
- Ensure that rates are administratively feasible. This includes taking metering and billing system constraints into account and avoiding unnecessary complexity that might confuse customers.
- Preserve the attractiveness of cost-effective load control/interruptible riders.

Q. You mentioned that several of the rate structure objectives imply using marginal costs for rate design. What are the reasons for basing rate structures on marginal cost?

A. A primary reason for using marginal costs as the basis for rates is to encourage customers to make economically efficient energy decisions; that is, to use an increment of electricity only if it has value to the consumer that is equal to or greater than the cost of supplying that increment of electricity (the marginal cost). Because the marginal cost of supplying electricity varies by season and time of day, time-differentiated rates result in more efficient electricity consumption decisions than rates that are not time-differentiated.

Q. Is there a second reason for using marginal costs as the basis for rate design?

A. Yes. A second reason is to reduce cross-subsidies. Cross-subsidies arise when costs attributable to consumption by one customer or group of customers are recovered from another customer or group of customers. For example, if the tail block price of a declining block rate were significantly below marginal cost, a customer large enough to consume in the tail block who increased use would pay less for the additional electricity than it costs OTP to provide the increment. Someone else must make up the difference – OTP's shareholders and/or its other customers. Neither alternative is fair or likely to result in customers' receiving high quality service or in the economic use of electricity. Another example is the use of non-seasonally differentiated rates in circumstances when customers' shares of consumption in winter and summer vary significantly. If high summer costs are recovered partly in winter months because rates are the same year-round, customers with relatively high air conditioning use in summer and who use gas to heat in winter are subsidized by customers who use relatively little air conditioning in summer but heat with electricity in winter.

Q. Is there a third reason for basing rate structures on marginal costs.

A. Yes. A third reason is that when rate structures are based on marginal cost, the utility's revenues are more likely to track its total costs as electricity consumption changes. For example, if energy charges are set at marginal cost, differences in energy consumption from the forecast used in the rate case will lead to changes in revenues that match changes in costs, giving the utility a reasonable opportunity to earn its authorized rate of return.

Q. What are the components of a marginal cost-based rate structure?

A. A full marginal-cost based rate structure has the following rate components: [1]

- A monthly customer charge to recover marginal customer-related costs (meter, service drop, customer-related expenses such as meter reading, billing, customer accounting, and customer information).
- A monthly distribution facilities charge per kW of design demand to recover the marginal costs of local distribution facilities (local primary, transformers, secondary lines). These facilities must be in place to serve one customer (or a small number of neighboring customers) all year, even though the customer(s) may not be making full use of the full capacity every month.
- Seasonal and TOD charges to recover time-differentiated generation, transmission and distribution substation/trunkline marginal costs.

Practical considerations such as the capability of customers' meters, limitations on customer characteristics in the billing system, and the objective of gradualism often require modifications to this structure.

IV. OTP'S USE OF MARGINAL COSTS IN THIS CASE

Q. In this rate case has OTP used marginal costs to compute its requested total revenue requirement?

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[1] The rate structure for large customers should also include a penalty for deviation of power factor outside of normal limits. OTP's current and proposed rates include such a charge.

A. No. As in most jurisdictions, OTP's proposed total revenue requirement is based on the utility's test-year embedded costs, with known and measurable changes.

Q. In this rate case has OTP used marginal costs to compute its revenue requirement for the major customer classes?

A. No. Rates overall must be set to recover embedded costs, but each customer class' revenue allocation could be based on something else, as it is in many states. OTP's proposed major class revenue allocations are based on the results of an embedded class cost of service study, but with modifications necessary to take into consideration rate design goals such as gradualism and fairness. The direct testimony of OTP witness Pete Beithon discusses the Company's proposed class revenue allocations.

Q. In this rate case has OTP used marginal costs to apportion to individual rates within a major customer class the revenue requirement allocated to that class?

A. Yes. In keeping with the objectives of improving the efficiency of price signals and reducing cross-subsidies, OTP analyzed the 2009 marginal cost of serving customers on each rate (i.e., the revenues that would be generated by charging marginal costs) within a class. Charging each rate a share of total class allocated revenue requirement equal to the rate's share of total class marginal cost revenue would be an application of the equal percentage of marginal cost ("EPMC") approach. However, to avoid unacceptable bill impacts, the EPMC shares of class revenue requirement were modified as a first step toward a more efficient and equitable allocation of class revenue requirement among rates.

Q. In this rate case has OTP used marginal costs to guide the design of individual rates?

A. Yes. As explained by OTP witness David Prazak, OTP began its rate design exercise by populating its rate model with 2009 marginal costs as tentative charges, and calculating the revenues those charges would produce when applied to test-year billing determinants. OTP then modified the tentative charges until the revenues from those charges produced the revenue target for that rate. These modifications generally used the following principles:

- Set the customer charges and the facilities charges below marginal cost.
- Keep the energy and demand charges as close as possible to full marginal cost.
- When reductions below marginal cost are required for demand and energy charges, maintain the marginal cost relationships, to the extent feasible. For example, if energy and demand charges must be set below marginal cost to achieve the target revenue for a rate, reduce both energy and demand charges by approximately the same percent.
- Eliminate declining blocks.
- Strive to maintain a logical relationship among the charges in closely-related rates (such as general service and large general service).

Q. How do rate structures with declining blocks fit with OTP's rate structure objectives?

A. Declining block rates, which price successive blocks of energy (or demand) at reduced prices, are generally not compatible with OTP's rate structure objectives. Rate structures with declining blocks are often not efficient or cost justified. Such rates give the impression that cost per unit declines as consumption (or load factor) increases, which may not be the case. When the lower-cost blocks are priced below marginal cost, consumption beyond the economically efficient level is promoted, leading to inefficient investment in capacity expansion and inefficient use of fuel and other resources.[2] Furthermore, pricing below marginal cost can lead to financial problems for the utility when usage in the below-cost blocks is greater than expected at the time the rates were set: the unanticipated revenues do not cover the unanticipated (marginal) costs. Declining blocks are unreasonable and discriminatory and create cross-subsidies within a rate class if large users, who benefit from low-priced blocks, do not have a lower cost of service than smaller customers within the class. Finally, declining blocks are viewed by some as antithetical to local, state, national and international efforts to counter global climate change by improving energy efficiency and promoting conservation.

[2] This is also true of the other blocks that are priced below marginal cost, to the extent that customers' usage ends in those blocks, but the effect is greater for the lower-cost blocks.

V. COMMISSION'S PREVIOUS POSITION ON USE OF MARGINAL COSTS IN RATES

Q. Has the Commission, in a prior proceeding, supported the use of marginal costs in setting revenue targets for individual rates within a class and structuring the charges within a rate?

A. Yes, but the issue has not been readdressed comprehensively for many years. In 1980 in a Northern States Power Company rate case, the Commission considered the PURPA Rate Design Standards. One of those standards—the Cost of Service Standard—is as follows:

> Sec. 111(d)(1) Cost of Service. Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class, as determined under section 115(a).
>
> Section 115(a) Cost of Service. In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(1), the costs providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determine on the basis of methods prescribed by the State regulatory authority…. Such methods shall to the maximum extent practicable—
>
> (1) permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and
>
> (2) permit identification of differences in cost-incurrence attributable to differences in customer demand and, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to a electric utility are likely to change if—
>
> a. additional capacity is added to meet peak demand relative to base demand; and
>
> b. additional kilowatt-hours of electric energy are delivered to electric consumers.

At that time, the Commission adopted the PURPA cost of service standard and, agreeing with Staff's recommendations, found "that marginal costs should be emphasized in developing time-of-day rates and that electric utility rates should reflect economic costs [defined by Staff as "costs associated with the units of production at the margin of production"] to the fullest extent possible."[3] The Commission also found "that marginal cost considerations are important in the designing of utility rates."[4] With regard to class revenue allocation, the Commission found that "moving class revenue responsibilities toward economic class costs would likely result in improved allocation of resources and conservation of scarce fuel. Therefore, the Commission finds the principle of moving to cost base rates over time, proper."[5]

Five years later, in an OTP rate case, the Commission approved a settlement agreement between OTP and Staff that addressed the PURPA cost-of-service standard. The Commission found that the settlement agreement "provides for the implementation of the [PURPA Cost-of-Service Standard] as determined under 16 U.S.C. 46 §2625(a)."[6]

The Commission also approved a settlement agreement in OTP's most recent rate case[7] that implemented rates based on marginal costs. The approved rate design was described in the direct testimony of OTP witness Albert D. Bartsch as:

- based on the view that "the pricing function must be used to encourage optimum utilization of the electrical system as well as provide pricing signals to customers based on the future cost of providing energy service." [p. 7: 16-19];
- including Demand Control services that are "based on marginal costs during the next five to seven years, to reduce summer and winter on-peak demands and increase off-peak consumption" (p. 6: 18-21];
- incorporating pricing changes to the duel fuel service that "have been made to reflect marginal costs for the next three to four years as the lower price limit, and competitive market constraints as the upper price limit" [p. 7:6-8]; and
- considering, in the design of specific price changes, "embedded cost of service, elasticity, impact and acceptability, continuity, simplicity, revenue stability, efficient resource utilization and marginal cost of service" [p. 8:19-19].

Q. Did the Commission address the PURPA declining block rate?

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[3] SDPUC Decision and Order F-3188, August 7, 1980, p.26.

[4] Ibid., p. 27.

[5] Ibid., p. 30.

[6] SDPUC Decision and Final Order on Rate Design F-3418, September 18, 1985, p. 2.

[7] SDPUC Order Approving Settlement Agreement and Tariffs, F-3691 and F-3647-5, October 30, 1987.

A. Yes. Another of the PURPA ratemaking standards required regulatory commissions to consider whether declining block rate structures were consistent with the goals of conservation, efficiency and equity:

> Sec. 111(d)(2): The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period.

In its 1980 NSP decision, the Commission adopted the declining block standard, but recognized the need for gradualism in eliminating such blocks.[8] In the 1985 OTP decision, the Commission rejected elimination of declining blocks by OTP because doing so would cause unnecessary hardship and confusion at the time that consumers were beginning to adjust to the new controlled service rate and residential demand control rate. However, the Commission left open the possibility of reconsidering the standard, by making their finding "subject to future revision."[9]

Q. In the over 20 years since the Commission's PURPA Cost-of-Service Standard decisions, have there been changes that the Commission should consider with respect to use of marginal costs and declining block structures in rate setting in South Dakota?

A. Yes. There have been numerous changes including:

- New rate standards added to PURPA by Congress
- National focus on energy efficiency and reduction in greenhouse gases
- Development of competitive wholesale electricity markets that make OTP's marginal cost of generation the same as the market price
- Increased consumer sophistication regarding complex pricing mechanisms.

Q. What new rate standards were added to PURPA?

[8] SDPUC Decision and Order F-3188, August 7, 1980, p.54.

[9] SDPUC Decision and Final Order on Rate Design F-3418, September 18, 1985, p. 2.

A. Concerned about energy efficiency, renewable energy and other energy-related matters, Congress passed the Energy Policy Act of 2005 ("EPAct"),[10] which included a variety of energy efficiency and demand management programs. EPAct also amended PURPA to add three new rate-design-related provisions for the State Commissions to consider or study:[11] (1) net metering for any customer with on-site generation that requests it; (2) offering of rates that vary by time period (e.g., standard time-of-day rates, critical peak pricing and real-time pricing) and reflect variations in the utility's costs of generating or purchasing wholesale power by period; and (3) provision of smart metering to customers requesting time-varying rates.

PURPA was also amended by the Energy Independence and Security Act of 2007 ("EISA 2007"). This legislation added a seventeenth rate design standard designed to promote energy efficiency investments:[12]

> (A) IN GENERAL—The rates allowed to be charged by any electric utility shall—
>
> (i) align utility incentives with the delivery of cost-effective energy efficiency; and
>
> (ii) promote energy efficiency investments.
>
> (B) POLICY OPTIONS—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—
>
> (i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;
>
> (ii) providing utility incentives for the successful management of energy efficiency programs;
>
> (iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;
>
> (iv) adopting rate designs that encourage energy efficiency for each customer class;
>
> (v) allowing timely recovery of energy efficiency-related costs; and
>
> (vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with

[10] The Domenici-Barton Energy Policy Act of 2005 (EPAct 2005).

[11] Title XII, Subtitle E.

[12] Section 532(a) of EISA.

> making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

Section 1307 of EISA 2007 also added standards on Consideration of Smart Grid Investments and Smart Grid Information. The latter calls for daily and hourly information to be provided to electricity purchasers, to the extent practicable, including: time-based electricity prices in the wholesale electricity market, time-based electricity retail prices or rates that are available to the purchasers, and the customer's energy consumption (in kWh), with pricing information provided on a day-ahead basis to the extent available.

Taken together, these amendments to PURPA illustrate the growing national efforts to improve energy efficiency and increase demand management, and the recognition that efficient rate design (that reflects marginal costs and market prices) is a key demand management and energy efficiency tool.

Q. How did the Commission respond to the 2005 and 2007 PURPA amendments related to rate design?

A. The Commission did not consider the 2005 net metering standard because the state legislature had already considered implementation of net metering and rejected it. At its July 11, 2007 meeting, the Commission voted not to adopt the time-based metering standard, finding "little evidence…that demonstrated that the adoption of this standard at this time would meet the PURPA goals of energy conservation, efficiency of facilities and resources and equitable consumer rates. The Commission further stated its finding "that adoption of the standard could result in the utilities being required to offer uneconomic programs that result in higher rates."[13] The Commission has not yet considered the new EISA 2007 standards.

Q. What are the implications of the PURPA amendments and the Commission's response with respect to using marginal costs to set rates?

A. The optional time-varying prices and associated metering contemplated by the PURPA amendments are designed to give efficient price signals to participating consumers

[13] Decision Regarding Interconnection and Time-Base Metering Standards; Notice of Entry of Order EL06-018.

regarding the timing of their consumption and the value of load shifting, peak load reductions, and participation in interruptible programs. In order for these price signals to encourage efficient behavior, they must be based as much as possible on marginal costs. Although the Commission did not adopt the PURPA time-based metering standard, the Commission has approved implementation of several OTP rates with a time-of-use feature, including Off-peak Water Heating, Duel Fuel, Off-peak Deferred Load – Thermal Storage, Residential Demand Control, Fixed Time of Delivery and the Off-Peak Rider. These rates and programs will also be most efficient if they are based on marginal costs.

Q. How has growing national concern about energy efficiency and greenhouse gases ("GHG") changed the regulatory environment with regard to use of marginal costs in rates?

A. In recent years there has been greater national concern about energy efficiency, energy independence and greater reliance on renewables, and control of GHG emissions, particularly by the electric utility industry. Most energy analysts expect the US to enact some form of GHG legislation – either a cap and trade program or carbon tax aimed at significantly reducing the country's GHG emissions – in the next few years. Meeting these targets will require significant changes in the way energy is produced and used. The GHG programs themselves will increase the marginal cost (and market prices) of electricity. Electric rates based on marginal cost will be an increasingly important tool for protecting utilities from the financial losses that could occur if they are pricing below marginal cost and sales are higher than expected. Using marginal cost will also be critical to encourage consumers to choose the most efficient appliances and energy types..

Q. How has the growth of competitive wholesale regional electricity markets changed the regulatory environment with regard to use of marginal costs in designing rates?

A. As a result of the development of competitive wholesale regional electricity markets, utilities such as OTP are participating every hour (or more often) in the wholesale market – either buying or selling. Most utilities that offer real-time pricing ("RTP") and critical peak pricing ("CPP") as part of their demand management efforts use market prices (or estimates of market prices) to set the generation portion of the RTP and CPP prices.

Time-of-Day prices in such jurisdictions typically reflect the patterns of market prices as well. In short, the generation component of these rates is derived from market prices because the market price is the marginal cost of generation for those utilities. The Minnesota Public Utility Commission recently accepted OTP rates that, like the rates proposed in this proceeding, were based on a marginal cost study that used market prices as the basis for the generation component.

Q. In 1985 the Commission was concerned that changing rate structures might confuse consumers that were just adapting to controlled service and residential demand control programs. Is customer understanding still a concern?

A. Customer understanding is always a consideration and an important rate design objective. However, consumers today face a variety of electricity service options in South Dakota. For example, residential customers have a choice of seven different rates or rate combinations, many of which have quite complex structures. These residential rates currently have features such as minimum bills, multiple declining energy blocks, seasonally-differentiated demand charges with 12-month ratchets, seasonally-differentiated and blocked energy charges, and various degrees of utility load control. Commercial customers face rate structures and service options that are even more complex. For example, the smallest business customers pay a rate that includes a monthly minimum (that includes an adder equal to 50% of the highest demand bill in the previous 11 months), three declining energy blocks, plus a fourth block that applies to energy use in excess of 200 kWh per kW of billing demand, and a demand charge that applies to monthly demand over 10 kW. The standard large commercial rate (which varies by voltage level of service) has two declining energy blocks, the last of which applies to all kWh in excess of 360 kWh per billing kW, and two declining blocks for demand. Billing demand is computed based on a formula that uses the customer's peak demand in the billing period and the customer's billing demand in the preceding 11 months. In short, the Commission has approved rate structures that are more complex than the marginal cost-based structures OTP is proposing in this case.

Furthermore, consumers do not need to understand the complexities of the *cost studies* that underlie their rates. Instead, to make efficient consumption decisions, they need to understand how their bill will change if they use more or less energy, or (in the case of TOU rates) shift load from peak to off-peak periods.

VI. MARGINAL COST APPROACH AND RESULTS

Q. What were the basic approaches that you and your team used to estimate OTP's marginal costs of providing electricity service?

A. Our goal was to ensure that the marginal costing methods accurately reflect OTP's participation in the regional electricity market, as well as the Company's planning and operating activities. For marginal costs of energy and generation capacity, we used a forecast of regional market prices of energy and capacity. For transmission, we used the financial marginal costs inherent in the MISO rules for wholesale transmission rates. For distribution substations and trunk feeders, we relied upon OTP's recent and forecast growth-related capital expenditures and the load growth that is driving those investments. For local distribution facilities we based our estimates on the cost of typical equipment configurations for customers of various types and sizes. Our marginal customer costs are based on the cost of typical meters and service drops and recent levels of customer-related expenses. The summary sheets from our study are located in Exhibit ___(HSP-1), Schedule 1.

Q. Please explain in more detail how you developed estimates of marginal energy costs.

A. OTP provided a commercial forecast of monthly energy prices (by MISO-defined peak and off-peak periods) at the Minnesota hub. We used two years of historical day-ahead prices at that hub to shape the monthly forecast into an hourly forecast. We adjusted these hourly prices for cash working capital and marginal energy losses to produce a marginal energy cost at each voltage level of service. This is a standard approach that I typically use.

Q. Please explain in more detail how you developed estimates of marginal generation capacity costs.

A. According to MISO rules, OTP must maintain sufficient (owned or purchased) accredited capacity to provide a specific reserve margin over monthly peak loads. OTP provided a forecast of seasonal capacity prices, and indicated that although the MISO requirement is a monthly requirement, capacity needed in a given month must generally be purchased for the entire season. Using five years of historic hourly OTP loads, we estimated the relative probability that a given hour is likely to be the seasonal peak hour, and multiplied these probabilities by the forecast seasonal market price (adjusted upward by 15 percent[14] to account for the MISO reserve margin rule) to produce estimated hourly generation capacity costs. These market price estimates were also adjusted by a cash working capital component and marginal losses.

Q. Please explain in more detail how you developed estimates of marginal transmission costs.

A. According to MISO rules, transmission owners' transmission revenue requirements are recovered through two types of zonal charges: the Network Integration Transmission Service ("NITS") rate and the Network Upgrade Charge ("NUC"). The monthly NITS and NUC charges are applied on the basis of a load-serving entity's monthly peak demand. Working with OTP staff, we developed forecasts of the NITS and NUC charges. Consistent with the way these rates are applied, we time-differentiated these equal monthly rates using estimates of the relative probability of a given hour's being the monthly peak hour, using five years of historic hourly OTP loads. These costs were adjusted for cash working capital and marginal losses.

Q. Please explain in more detail how you developed estimates of marginal distribution substation and trunk feeder costs.

A. Working with OTP staff, we identified growth-related distribution substation and trunk feeder projects in the period 2005-2008. We converted this investment to 2009 dollars and divided by an estimate of non-coincident substation load growth over the same period. We annualized this typical investment per kW of load growth using an economic carrying charge and added estimates of O&M, overheads, and working capital requirements to produce an annual marginal cost. Using a statistical analysis of five years of load patterns on a sample of substations, we estimated the relative probability of a

[14] OTP is a member of MAPP, and MISO uses MAPP's standard for its members who are also members of MAPP.

given hour's being the peak hour on distribution substations. We used these probabilities to time-differentiate the annual cost, and adjusted them for marginal demand losses.

Q. Please explain in more detail how you developed estimates of local distribution facilities marginal costs.

A. OTP provided estimates of the installed costs of local facilities (secondary lines, transformers, and the local portion of primary taps) for various customer types, sizes and characteristics. OTP provided similar information on local facilities and lighting facilities for categories of area and street lights. We converted these investments into a cost per design kW by dividing by transformer capacity. These marginal investment values were annualized as described above for distribution substations.

Q. Please explain in more detail how you developed estimates of meter and service drop marginal costs.

A. OTP provided estimates of the installed costs of meter (and associate equipment) and service drops for various customer categories. These marginal investment values were annualized as described above for distribution substations.

Q. Please explain in more detail how you developed estimates of marginal customer-related expenses.

A. We analyzed five years of historical levels of customer-related expenses and excluded accounts that are either not marginal (e.g., marketing expenses), or not applicable in South Dakota (the costs of the Conservation Improvement Project (CIP) in Minnesota). We also excluded costs that are recovered in separate charges and, therefore, should not be included in marginal customer costs that will be used to set customer charges (e.g., cost of equipment provided to load control customers and costs of connection/reconnection). Working with OTP staff, we identified expenses that are incurred equally for all customers and those that are incurred for specific sub-sets of customers. Using the resulting weighting factors, we developed estimates of marginal customer-related expenses by class.

Q. How did you develop seasonal and diurnal costing/pricing periods?

A. The development of marginal energy, generation capacity, transmission and distribution substation/trunk feeder marginal costs resulted in hourly cost estimates for a typical weekday, Saturday and Sunday in each month. We summed these hourly costs across cost components and used the resulting total hourly marginal costs in a statistical model to identify periods that (1) group hours with similar costs, (2) are consistent with the number of periods that OTP believes is administratively feasible (two seasons and three diurnal periods), (3) give special attention to the coldest months within the broad "winter" season, (4) and are reasonably simple and easy for consumers to remember. We concluded that the periods proposed by OTP in its recent Minnesota rate case, and approved by the Minnesota Commission, meet these criteria.

Q. Are these the same periods currently in use in South Dakota?

A. No. The current rates with seasonal differences define Winter as November – April and Summer as May – October. The proposed rates define Winter as October – May and Summer as June – September. There are several different definitions of diurnal pricing periods in current rates. Several of the load control rates allow for control in up to 14 (unspecified) hours per day. The fixed time of delivery rates allow for control from 7 a.m. to 11 p.m. (16 hours per day). The Off-Peak Rider applicable to LGS service defines on-peak as 8 am to 10 pm, Monday through Saturday, with all other hours defined as off-peak. The periods used in designing OTP's proposed rates have different peak and off-peak definitions and include a shoulder period. The proposed periods are based on up-to-date information and reflect the time patterns of hourly marginal costs we expect OTP to face in the next few years.

Q. How did you use these costing/pricing periods?

A. We summed the hourly costs (or averaged them, in the case of marginal energy costs) across periods. These marginal costs by period were the inputs for OTP's analysis of class and rate marginal cost revenues, and the starting point for OTP's proposed rate designs.

VII. IMPLICATIONS OF MARGINAL COST RESULTS FOR OTP'S RATE DESIGN

Q. What are the general implications of the marginal cost study results for OTP's rate design?

A. A comparison of OTP's current rates and the marginal cost results suggests several changes that would improve the efficiency of OTP's South Dakota rates:

- Seasonality – Because it operates in MISO, OTP's summer marginal costs are higher than its winter marginal costs. Only the Dual Fuel and Residential Demand Control rates currently have seasonally-differentiated charges. Because seasonal differentials require no additional metering, incorporation of seasonal differentials in all rates[15] would be a readily achievable and economically important step.

- Very Low Energy Charges –The Dual Fuel and Fixed Time of Delivery energy charges are not adjusted for the cost of energy and are significantly below marginal cost. These below-cost prices send inefficient price signals and create cross-subsidies. The energy prices in these rates should be increased significantly.

- Declining Blocks – Many of OTP's rates include declining energy blocks, and several also include declining demand blocks, with tail block prices that are well below marginal cost. These rate structures send a signal that OTP is rewarding customers for using more. Elimination of declining blocks would produce more efficient, equitable and less complex rate structures.

- Minimum Charges – The current minimum charges are generally well below marginal customer and facilities costs and fixed charges are below the corresponding marginal costs. Defining the minimum charge as the sum of more cost-reflective customer and facilities charges would reduce cross-subsidies within the rates.

- Residential Demand Control – The seasonal demand charges in the Residential Demand Control Rate are higher in the winter than in summer, reflecting OTP's pre-MISO cost relationship. These should be updated to reflect OTP's current seasonal pattern of capacity costs.

- Time-of-Day Rates – The marginal cost study shows very large differences in costs across the hours of the day and days of the week. Offering a time-of-day rate option

[15] Except lighting and siren rates.

to Large General Service customers would significantly improve price signals and give these customers greater control over their bills.

VIII. LIKELY EFFICIENCY IMPROVEMENTS FROM OTP'S PROPOSED RATE DESIGNS

Q. Are OTP's proposed rate structures likely to produce efficiency improvements?

A. Yes. I have analyzed the relationships among current charges, marginal costs and proposed charges (included in OTP Witness Prazak's direct testimony). OTP has recognized in its proposed rate designs the marginal cost implications described in the previous section. With a few minor exceptions, the important price signals for marginal kWh and kW use are closer to marginal cost in the proposed rates than in the current rates. As customers respond to the new prices, they are likely to make electricity consumption decisions that are more efficient.

Q. Does this complete your direct testimony?

A. Yes, it does.

OTTER TAIL POWER COMPANY
2009 MARGINAL CAPACITY (G+T+D) AND ENERGY COST
BY VOLTAGE LEVEL & COSTING PERIOD

		June - September			October - May		
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	**Secondary**						
	Monthly Capacity Costs (2009 Dollars per kW)	$9.73	$2.69	$0.04	$3.77	$0.88	$0.38
	Seasonal	$12.45			$5.03		
	Annual	$7.51					
	Energy Costs (2009 Cents per kWh)	13.276	10.176	6.061	11.914	9.690	6.840
	Seasonal	8.843			8.929		
	Annual	8.900					
	Sum of Marginal Energy and Capacity Costs (2009 Cents per kWh)						
	Seasonal	10.545			9.619		
	Annual	9.929					
(2)	**Primary**						
	Monthly Capacity Costs (2009 Dollars per kW)	$9.66	$2.66	$0.04	$3.74	$0.88	$0.38
	Seasonal	$12.36			$5.00		
	Annual	$7.45					
	Energy Costs (2009 Cents per kWh)	13.219	10.134	6.041	11.856	9.645	6.810
	Seasonal	8.809			8.887		
	Annual	8.861					
	Sum of Marginal Energy and Capacity Costs (2009 Cents per kWh)						
	Seasonal	10.498			9.573		
	Annual	9.882					
(3)	**Transmission**						
	Monthly Capacity Costs (2009 Dollars per kW)	$8.22	$1.79	$0.03	$3.39	$0.76	$0.09
	Seasonal	$10.04			$4.25		
	Annual	$6.18					
	Energy Costs (2009 Cents per kWh)	12.868	9.881	5.921	11.505	9.369	6.629
	Seasonal	8.599			8.637		
	Annual	8.624					
	Sum of Marginal Energy and Capacity Costs (2009 Cents per kWh)						
	Seasonal	9.971			9.220		
	Annual	9.471					

OTTER TAIL POWER COMPANY
SUMMARY OF MONTHLY MARGINAL FACILITIES-RELATED COSTS
PER KW OF DESIGN DEMAND AND PER CUSTOMER

	Customer Class	Monthly Facility Cost per kW of Design Demand	Estimate of Typical Design Demand by Customer	Monthly Facility Cost per Customer
		($/kW)	kW	($/customer/mo.) (1)*(2)
		(1)	(2)	(3)
	Residential			
(1)	Urban	$1.37	8	$11.38
(2)	Rural	2.17	21	44.92
(3)	Apartment, Gas	1.39	9	12.65
(4)	Apartment, Electric	0.85	5	3.85
(5)	**Farm**	2.67	21	55.38
	Small Commercial			
(6)	Stand-Alone customer, overhead	0.64	50	32.10
(7)	Stand-Alone customer 3ph, overhead	0.82	75	61.57
(8)	Shared-customer 3ph, overhead	0.87	75	65.50
(9)	Stand-Alone customer, underground	1.06	50	52.91
(10)	Shared-customer 3ph, underground	1.50	75	112.47
	Large Commercial (Secondary Only)			
(11)	101-150kVa, 3ph	0.94	150	140.36
(12)	151-300kVa, 3ph	0.65	300	193.74
(13)	301-500kVa, 3ph	0.52	500	259.01
(14)	>501 kVa, 3ph	0.40	2,600	1,042.26
(15)	**Very Large Commercial (Secondary TOU)**			
	3000 kVa (LGS)	0.40	3,000	1,208.29
	Large Commercial (Primary)			
(16)	3000 kVa (LGS)	0.27	3,000	819.34
(17)	5000 kVa (LGS TOU)	0.29	5,000	1,459.13

OTTER TAIL POWER COMPANY
SUMMARY OF MONTHLY MARGINAL FACILITIES-RELATED COSTS PER COMPONENT

	Customer Class	Monthly Facility Cost per Component
		(1)
	Lighting	
(1)	Area Light 1 HPS 9 (no pole), underground	11.60
(2)	Area Light 1 HPS 9 (no pole), overhead	10.74
(3)	Street Light - (no light, no pole), underground	7.69
(4)	Street Light - (no light, no pole), overhead	6.84

OTTER TAIL POWER COMPANY
SUMMARY OF MONTHLY MARGINAL CUSTOMER-RELATED COSTS
BY CUSTOMER CLASS

			Monthly Marginal Customer Cost per Customer (2009$ /mo.)
	Residential		
R-01	Residential		$10.11
R-03	Residential Controlled Demand		16.77
R-91	Residential Water Heat Controlled		7.07
I-02	Residential Controlled Dual Fuel		7.80
I-03	Residential Controlled Deferred Load		10.82
I-04	Residential Fixed Time Of Delivery		10.82
M-42	Street Lighting		3.67
	Flood Lighting		3.67
	Sign Lighting		3.67
	Energy-Only Street & Area Lighting - Metered		4.26
	Energy-Only Street & Area Lighting - Non-Metered		3.67
	Athletic Field Lighting- South Dakota Only		7.02
	Commercial and Industrial		
G-01	General Service < 20 kW		17.51
G-01	General Service >= 20 kW		26.50
G-02	General Service (Control Demand)		36.39
F-61	Farm Service		12.34
C-02	Large Commercial Service		
		Secondary	254.44
		Primary	303.69
C-03	Large General Service (Real Time Pricing)		
		Secondary	351.89
		Primary	400.99
C-04	Large General Service (Off Peak Rider)		
		Secondary	351.89
		Primary	400.99
C-09	Large General Service (Time Of Use)		
		Secondary	351.89
		Primary	400.99
R-91	Commercial Water Heat Controlled		6.33
I-01	Large Commercial Controlled Dual Fuel		34.17
I-02	Small Commercial Controlled Dual Fuel		14.35
I-03	Small Commercial Controlled Deferred Load		17.23
I-04	Small Commercial Fixed Time Of Delivery		17.23
I-06	Bulk Interruptible		405.87
M-03	Irrigation Service		23.56
M-04	Commercial Time Of Use		259.06
	Street Lighting		3.67
	Flood Lighting		3.67
	Sign & Area Lighting		3.67
	Energy-Only Street & Area Lighting - Metered		4.26
	Energy-Only Street & Area Lighting - Non-Metered		3.67
	Miscellaneous		
	Streetlighting		3.67
	Other Public Authority		25.21

HETHIE PARMESANO
Senior Vice President

Dr. Hethie Parmesano is an expert on electricity, gas, and water industry costing, pricing, sector structure, and regulation. In recent years she has been involved with projects dealing with regulation, restructuring, and privatization of state-owned utilities in a variety of different settings, including the U.K., Spain, Saudi Arabia, India, Ireland, Japan, Kenya, Greece, El Salvador, Argentina, Barbados, Brazil, Cambodia, and Mexico. Dr. Parmesano also has extensive experience with costing, pricing, and restructuring issues in the U.S. and Canadian utility industries. Her work both in the U.S. and abroad has involved issues such as regulating distribution companies, metering and settlement for customers with retail access, transmission pricing, rate structure for Provider-of-Last-Resort service, backup rates for distributed generation, real-time pricing and other innovative pricing options, and efficient pricing of bundled service. She teaches seminars on costing and pricing topics, directs a NERA-sponsored industry group called the Marginal Cost Working Group, and has testified widely on utility matters before regulatory agencies.

Education

Cornell University
Ph.D., Economics, 1973
M.A., Economics, 1971
Honors: received a National Science Foundation Traineeship
Major Areas: economic development, international economics, and economic theory

Colby College
B.A., *cum laude*, Economics, 1968

Professional Experience

NERA Economic Consulting

1980- Senior Vice President, Vice President, Senior Consultant, Senior Economic Analyst

Dr. Parmesano has been involved in numerous economic studies for electric, gas, and water utilities. She has specialized in issues related to marginal cost pricing, regulatory and electricity industry reform, strategic planning and resource planning. She has been involved in electric industry restructuring efforts in the U.S., Canada, U.K., Ireland, Greece, Kenya, Mexico, Argentina, Brazil, Spain, El

Salvador, Cambodia, Japan, and India. She has testified in regulatory proceedings in Arizona, California, Colorado, Florida, Idaho, Illinois, Indiana, Iowa, Maine, Maryland, Massachusetts, Minnesota, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Texas, Utah, and Alberta and Nova Scotia, Canada. Her responsibilities include teaching a series of seminars on marginal costing for the staffs of electric utilities and regulatory commissions.

Los Angeles Department of Water and Power (LADWP)

1977-1980 Staff Economist

Participated in a variety of rate studies and other economic analyses. Responsibilities included testimony at LADWP's PURPA hearings on electric rates, membership in the California Marginal Cost Pricing Task Force, and participation in environmental impact studies of proposed LADWP actions and projects.

Los Angeles City Planning Department

1973-1977 Economic Analyst

Participated in employment and demographic forecasting as well as economic impact analyses of city plans. Was also on the faculty at California State Polytechnic University at Pomona, teaching graduate courses in urban research techniques and computer applications in planning.

Languages

English – Excellent
Spanish – (reading) Good
French – (reading) Good

Project Experience

Otter Tail Power Company, Fergus Falls, MN 2007-08. Prepare a report on the appropriateness of phasing out or eliminating declining block rates; update marginal cost study; recommend marginal cost-based rate design for major customer classes; provide expert testimony in rate case in support of proposed marginal cost-based rates.

Otter Tail Power Company, Fergus Falls, MN 2006. Developed a revenue-neutral, marginal-cost-based, time-of-day rate for large general service electric customers. Assignment included extensive analysis of alternative pricing periods.

Alberta Electric System Operator, Canada 2006. Conducted a review of AESO's transmission cost-of-service study and stakeholder comments.

Newfoundland Power, Canada 2006. Prepared a study of NP's marginal distribution and customer costs, and computed marginal cost revenues (all elements) by rate class.

Fair Trading Commission of Barbados, Barbados 2006. Conducted marginal and embedded cost studies of Barbados Light & Power Co., Ltd; reviewed and commented on the utility's regulatory accounting policies, system planning and load forecasting practices; advised the Commission on rate base and rate of return policies; assessed the appropriateness and feasibility of time-of-use rates in Barbados; and provided training to Commission staff.

Newfoundland & Labrador Hydro, Canada 2006. Directed a marginal cost study of NLH's generation and transmission systems, and implications of the marginal cost results for rate design.

Xcel Energy, Minneapolis, MN 2005. Prepared a marginal cost study for filing in Xcel Energy's rate case in Minnesota.

Midwestern Electric Utility, Midwestern US, 2004-05. Directed a study of the utility's marginal costs of electric distribution service.

Otter Tail Power Company, Fergus Falls, MN 2004-05. Directed a study of the distribution costs avoided as a result of demand-side management, and the design and size of credits for distribution costs avoided as a result of distributed generation.

Nicor Gas, Naperville, IL 2004-05. Directed a marginal cost of gas study and advised the utility on a marginal cost-based gas delivery rate structure. Filed testimony in Nicor Gas' rate case on these issues.

Manitoba Hydro, Winnipeg, Manitoba Canada 2004-05. Directed a study of the appropriateness of time-of-use and inverted block electricity rate structures for Manitoba.

NSTAR Electric, Westwood, MA 2004. Testified for NSTAR on issues related to standby rates for customers with generation.

Manitoba Hydro, Winnipeg, Manitoba Canada 2004. Directed a study of appropriate methods for classification and allocation of generation and transmission costs in an embedded cost-of-service study for a hydro-dominated utility with significant wholesale transactions.

Commission for Energy Regulation of Ireland, Dublin, Ireland, 2001, 2002, 2004-05. Engaged by the Commission for Electricity Regulation (CER) to assist in the evaluation of the electricity supply tariff submission of the retail energy supplier. Role was to (1) help determine tariff objectives and constraints; (2) develop cost-based illustrative tariffs that would meet those objectives as much as possible, along with transition measures that could be used to move tariffs toward a more optimal set; (3) compare the company's submission to the illustrative tariffs; and (4) make recommendations to CER. Currently directing a major study of electricity transmission, distribution, and supply tariff structures, which involves conducting a marginal cost study and screening alternative structures.

Los Angeles Department of Water and Power (LADWP), Los Angeles, CA, 2003-present. Leading a group providing assistance to Los Angeles' municipal utility in the areas of marginal and embedded costing, tariff design, tariff development process, and support in tariff-related litigation.

Portland General Electric Company (PGE), Portland, OR 2003-04. Assisted PGE in settlement negotiations regarding partial requirements service to distributed generation.

Electricity Regulatory Board of Kenya, Nairobi, Kenya, 2001-03. Led a NERA team charged with helping the ERB develop a new electricity tariff policy consistent with fair and effective regulation as well as with the country's goals of economic development, private capital attraction, and poverty elimination. NERA's work included recommended policies on revenue requirement determination, revenue allocation, tariff design, transition mechanisms, connection charge policy, transmission pricing, purchased power agreements, and retail competition. The NERA team also prepared models for use in tariff review by the ERB staff and provided training to the ERB and other stakeholders.

Mid-western US utility, 2001. Engaged to conduct a qualitative review of the company's electricity tariffs as the first phase of a three-phase project to restructure tariffs. NERA found that the current tariffs were not well-designed to deal with the cost and operating changes resulting from the newly-formed ISO, that the company's load control programs were not designed for the purposes for which they are currently being used, and that complex traditional tariff structures could be eliminated with greater use of time-of-use pricing structures.

Mid-western US Public Power District, 2001. Helped a mid-western public power district update its wholesale rate structure to better reflect marginal production costs, NERA prepared estimated of marginal generation capacity costs, developed a set of optimal demand charges based on marginal cost, and determined whether the new production demand charges being proposed were moving toward those optimal levels.

Direct Service Industries, Portland, Oregon, 2001. Assisted the DSIs in their intervention in the rate case of the Bonneville Power Administration, arguing that implementing rates for all consumer groups based on marginal cost prices at the margin (tiered rates) was a superior solution to the problem of high-priced marginal resources than using average pricing for all.

Public Power Corporation of Greece (PPC), Athens, Greece, 2001. Participated with other NERA economists in development of a draft Distribution Tariff Code, covering all aspects of distribution tariff setting and line extension policies. The project included preparation of estimates of the marginal costs of electricity distribution in Greece, the distribution company's revenue requirement, and sample marginal cost-based tariffs that produce that revenue requirement.

Rochester Gas & Electric Corporation (RG&E), Rochester, New York, 2001-2003. Led group that prepared studies of the marginal costs of gas and electric service for RG&E. Provided testimony on these studies and efficient tariffs developed from them, including a price floor for economic development contracts, and backup rates for distributed generation.

New York State Electric & Gas Corporation (NYSEG), Binghamton, NY, 2000-2003. Assisted NYSEG in the development of updated methods for computing marginal costs of electricity service. The assignments included use of marginal costs in setting economic development rates.

Large Southern US Electric Utility, 2001. Led a group of economists in the development of a retail pricing strategy for an investor-owned utility. The strategy will help the company prepare for coming retail access and implementation of an RTO.

Brazilian Electricity Regulatory Agency (ANEEL), Brasilia, Brasil, 2000. Directed a NERA team assisting the regulatory commission in developing policies and procedures for setting and revising electricity tariffs for the newly privatized distribution companies in the country.

Secretaria de Energia, Mexico City, Mexico, 1999-2000. Was part of a NERA team advising the Mexican government on electric industry restructuring. Directed the Tariffs Task Force for this project.

Andhra Pradesh Electricity Regulatory Commission, Hyderabad, India, 1999-2000. Directed a NERA team providing tariff-related assistance to the newly formed regulatory commission in the state of Andhra Pradesh. Responsibilities included staff training, development of a tariff philosophy, drafting of tariff filing guidelines and associated commission procedures, and on-site assistance to the commission during its review of the first tariff filed by the transmission and distribution licensee. Led team that developed costing and tariff design models for use by the commission and its staff.

US Power Exchange, 1999. Led group that developed an unbundled cost of service study for a US power exchange. The project included identifying the activities associated with each service provided, determining which of the costs of each activity were fixed and which variable, identifying cost drivers for each type of cost, and recommending methods for allocating common costs to minimize pricing distortions.

Ontario Hydro Services Company, Toronto, Ontario, 1999. Provided assistance to OHSC in the development of transmission rates, including cost-of-service allocations, evaluation of alternative rate designs, and participation in the stakeholder process.

Salt River Project (SRP), Phoenix, Arizona, 1998. At the request of the Board of Directors of the Salt River Project (SRP), reviewed SRP Management's proposed bundled and unbundled electric price plans and provided recommendations to the Board. The focus of the review was on (1) the proposed class allocations; (2) the proposed price plans; (3) the cost studies on which they are based; and (4) the relationship between the bundled and unbundled prices.

Rochester Gas & Electric Corporation (RG&E), Rochester, New York, 1997. Directed a NERA team that undertook the cost studies and rate design analysis for pricing new services that RG&E will be offering to electricity retailing companies when retail open access is offered. These services include special metering, non-standard billing, and administration of balancing and settlement.

Government of Argentina, Argentina, 1997. Advised the Government of Argentina on ways to improve the operation of the electricity sector, with special emphasis on expansion of retail access, metering and settlement mechanisms, distribution tariffs, retail open access, demand-side management, distortions caused by taxes and subsidies, and quality standards and penalties for distribution concessionaires. This effort was a part of the first formal review -- undertaken by NERA -- of the structure and functions of the Argentine electricity sector since its radical reform in 1992.

Orissa Electricity Regulatory Commission, Orissa, India, 1994-1999. Participated on the NERA team responsible for the design and implementation of Orissa Electricity Regulatory Commission, the first independent state regulatory commission in India. The Commission was created as a key part of the overall reform and restructuring of the Orissa electric state power sector. Responsibilities included: organizational design; development of rules and procedures for tariff approval; participation in drafting of enabling legislation; design of regulations and license; design and implementation of on-site regulatory training; on-site consulting on marginal cost analysis; and rate design.

Banco Brascan, Natal, Brazil, 1997. Was part of a NERA team assisting Banco Brascan to develop a proposed tariff system, efficiency program, and regulatory mechanism to be detailed in the concession contract for the privatization of COSERN, an electric distribution company in northeast Brazil. Work included analysis of the tariff structure, regulatory policies, and socio-political factors likely to affect revenues of the new firm.

Potential Investors in Electricity Distribution, El Salvador, 1997. Participated in a presentation to introduce potential investors to the El Salvadoran electricity sector. The presentation explained the reform program and regulatory structure and discussed areas of concern for investors in privatized distribution companies.

Iberdrola, Spain, 1997. Participated on a NERA team advising Iberdrola, a vertically-integrated electric utility in Spain, during the restructuring of the country's electric industry. Provided advice on tariff structure, the cost basis for prices, mechanisms for recovery of strandable costs, and regulatory mechanisms. Work included providing training sessions to Iberdrola staff members.

Manitoba Hydro, Winnipeg, Manitoba, 1997. Led group that prepared a marginal cost study and report on the appropriateness of marginal cost-based electric rates for Manitoba.

New York State Electric & Gas Corporation (NYSEG), Binghamton, New York, 1997. Helped NYSEG develop its retail rate structure applicable when the utility's retail customers are eligible for retail open access. Work included testimony before the New York State Public Service Commission.

Nova Scotia Power Incorporated, Halifax, Nova Scotia, 1995. Testified before the Nova Scotia Utility and Review Board regarding proposals to restructure rates to improve the utility's competitive position.

Haryana Power Sector, Haryana, India, 1994-1995. Was a member of the NERA team preparing a major restructuring study of the Haryana State Electricity Board. The study examined all aspects of the power sector and recommended that the Haryana State Electricity Board be broken up into separate generation, transmission, and distribution entities. The project output included a detailed plan for implementing the restructuring proposal.

Los Angeles Department of Water and Power (LADWP), Los Angeles, California, 1991-92. Served as principal advisor to the Los Angeles Department of Water and Power in connection with a major restructuring of water rates. Work involved participating with the Mayor's Blue Ribbon Committee on Water Rate Structure. Attended virtually every meeting of the full committee and its subcommittees, offering advice on costing and rate design. One major task was to determine whether the rate structures being contemplated by the Committee were likely to cause financial difficulties for the Department. Also prepared a study of the marginal costs of the Los Angeles water system, a modification of which was ultimately used by the Committee to develop its inverted block rate proposal to the Mayor.

Publications

"Major Electricity Customer Pricing Options: The Case of Saudi Arabia," *The Electricity Journal*, January 2008

"Rate Design Is the No. 1 Energy Efficiency Tool," *The Electricity Journal,* July 2007.

"Portable Entitlements: Unlikely to Resolve Transition Dilemma," Letter to the Editor, *The Electricity Journal*, November 2004.

"The Thaw: The End of the Ice Age For American Utility Rate Cases -- Are you Ready?" *The Electricity Journal*, July 2004

"Standby Rates Issue is More Nuanced Than Authors Let on," Letter to the Editor, *The Electricity Journal*, November 2003, pp. 3-4.

"Standby Service to Distributed Generation Projects: The Wrong Tool for Subsidies" *The Electricity Journal*, October 2003.

"Making Every Electricity Consumer a Market Participant (Putting Demand Back in the Equation)," *The Electricity Journal*, April 2003.

"Use Tax Policy, Not Cross-Subsidies, to Aid the Poor," Letter to the Editor, *The Electricity Journal*, July 2002.

"An Introduction to Financial Transmission Rights," with Hamish Fraser and Karen Lyons, *The Electricity Journal*, December, 2000.

"Residential Electricity Tariffs: Getting the Structure Right," with Veronica Lambrechts, presented at online conference Energy Resource 2000, May 15-29, 2000.

"Letter to the Editor: Argument for Embedded Costs Has Basic Flaws," with Amy McCarthy, *The Electricity Journal* , March 1999.

"The Effects of the 1990 Clean Air Act on System Dispatch and Marginal Costs," with Bruce Ambrose and John Wile, *The Electricity Journal*, November 1993.

"The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey," NERA Working Paper, February 1992.

"Discount Electric Rates: Who Should Bear the 'Cost'?," with Carrie J. Hightman, NERA Working Paper, June 1991.

"Avoided Cost Payments to Qualifying Facilities: Debate Goes On," *Public Utilities Fortnightly*, September 17, 1987.

Impact of Rate Structure on Demand-Side Management Programs - Phase I Report, EPRI EM 4791, September 1986.

"Comments on John Wender's Article On Class Revenue Requirements," *Electric Potential*, Vol. 1, No. 2, November December 1985.

"The Evolution in U.S. Electric Utility Design," with Catherine S. Martin, *Annual Energy Review*, 1983.

"Pricing the Electrical Output of Cogeneration and Small Power Projects," *NERA Topics*, October 1983.

Testimony

Direct, Rebuttal and Surrebuttal testimony regarding rate design on behalf of Otter Tail Power Company. Before the Minnesota Public Utility Commission, MPUC Docket No. E-017/GR-07/1178, Oct. 2007 – Mar. 2008.

Prefiled direct testimony regarding proposed time-of-day rate for large general service customers on behalf of Otter Tail Power Company. Before the State of North Dakota Public Service Commission, Docket No. PU-07-03, June 2007.

Expert Report and associated oral testimony regarding alleged overcharging of governmental electric customers by the Los Angeles Department of Water and Power. Los Angeles County, Los Angeles Unified School District, Los Angeles County Metropolitan Transportation Authority, and Los Angeles Community College District ex rel. Barakat Consulting Incorporated and Samir F. Barakat, Plaintiffs v. Los Angeles Department of Water and Power and Does 1-50, Defendants. Superior court of the State of California for the County of Los Angeles, No. SCVSS100 293. August 2006 – January 2007.

Direct testimony regarding natural gas distribution marginal costs and rate design on behalf of Nicor Gas before the Illinois Commerce Commission. Filed November 2004.

Rebuttal testimony regarding standby rates on behalf of NSTAR before the Massachusetts Department of Telecommunications and Energy. Case DTE 03-121, April 2004.

Direct testimony regarding marginal gas and electricity costs on behalf of Rochester Gas & Electric Corporation before the New York Public Service Commission. RG&E was proposing to increase the degree to which its tariff structures reflect marginal costs. Case No. 02-E-0198, February 15, 2001.

Direct testimony regarding the supplemental proposal of the Bonneville Power Administration on behalf of the Direct Service Industries. The Companies on whose behalf this testimony is filed were proposing that BPA adopt a tiered rate structure, with the second tier price set at market price, as a substitute for BPA's proposal to charge a rolled-in average of the cost of energy. Case No. WP-02-E-DS/AL-02, March 2001.

Direct and supplemental testimony before the Public Utilities Commission of Ohio on behalf of Dayton Power & Light Company regarding shopping credits for consumers who choose another supplier of generation services and a forecast of switching rates by consumer category. Case No. 99-1687-EL-ETP, March and May 2000.

Rebuttal testimony before the Illinois Commerce Commission on behalf of Illinois Power Company related to the advisability of unbundling revenue cycle services; the appropriate basis for credits for these services, if unbundled; and the role of marginal costs in a world of retail access, February 10, 1999.

Rebuttal and Surrebuttal testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company regarding Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design, June 26, 1998 and August 31, 1998.

Testimony before the Salt River Project Board of Directors regarding SRP Management's Proposed Electric Price and Service Plan Changes Effective December 31, 1998, October 1, 1998.

Rebuttal testimony before the Public Utility Commission of New Mexico in the Matter of the Commission's Investigation of the Rates for Electric Service of Public Service Company of New Mexico, Case No. 2761, May 6, 1998, regarding electric rate unbundling.

Direct testimony before the Public Utility Commission of New Mexico in the Matter of the Petition of the City of Albuquerque to institute a retail pilot load aggregation program and its request for related approvals, Case No. 2782, April 16, 1998, regarding stranded cost recovery and other aspects of a pilot retail access program.

Testimony before the Public Utility Commission of New Mexico on behalf of Public Service Company of New Mexico, Case No. 2761 to explain the institutional conditions necessary for any reasonable unbundling of PNM's retail electricity rates, November 3, 1997.

Affidavit filed with the New Mexico Supreme Court in *Public Service Company of New Mexico vs. the New Mexico Public Utility Commission*, Case No. 2761 in support of PNM's request for a writ of mandamus, and request for stay regarding the NMPUC's order that PNM prepare unbundled electricity rates, October 8, 1997.

Direct and Responsive Testimony before the New York Public Service Commission on behalf of New York State Electric & Gas Corporation as part of NYSEG's rate/restructuring filing in compliance with Public Service Commission Opinion and Order 96-12 regarding rate design for retail access, September 27, 1996 and April 21, 1997.

Testimony before the Oregon Public Utility Commission on behalf of Portland General Electric Company - Case UM 827 on methods for estimating the marginal costs of electric utilities, April 7, 1997.

Rebuttal Testimony before the California Public Utilities Commission on behalf of Southern California Gas Company in the Biennial Cost Allocation Proceedings regarding two specific marginal cost issues—inclusion of replacement costs for existing equipment in marginal cost estimates and use of the "new customer only" approach to customer costs, August 8, 1996.

Direct Testimony before the Nova Scotia Utility and Review Board on behalf of Nova Scotia Power Incorporated in the matter of the Public Utilities Act, R.S.N.S. 1989, C. 380, as amended and in the matter of an Application of Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations; regarding rate restructuring to improve the utility's competitive position, December 11, 1995.

Rebuttal Testimony before the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company in Cause No. 40125, regarding an experimental real-time pricing tariff for large industrial customers, February 28, 1995.

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission, Docket Nos. 94-0134 and 94-0223 on behalf of Illinois Power Company, August 1994 regarding Illinois Power's proposal for a tariff that would allow contracts to prevent residential, commercial, and industrial electric customers from choosing an uneconomic municipal by-pass option.

Direct and Rebuttal Testimony before the Public Utility Commission of Texas, Docket No. 12957-TST-17-0 on behalf of Houston Lighting & Power Company, July 1994 regarding Houston Lighting & Power's proposal for a tariff to permit negotiated contracts with electric customers who have uneconomic bypass options.

Testimony and Comments before the Public Service Commission of Nevada, Docket No. 93-11045 on behalf of Nevada Power Company, June 2, 1994 and June 23, 1994 regarding competition, standby rates and environmental externalities in marginal energy costs. (Testimony and Comments were filed, but case settled before hearings.)

Prefiled Rebuttal Testimony before the State of Maine Public Utilities Commission, Docket No. 92-315 on behalf of Central Maine Power Company, August 18, 1993 regarding resource planning, rate structures, and avoided cost investigation.

Prefiled Rebuttal Testimony before the Indiana Utility Regulatory Commission in Cause No. 39623 on behalf of Northern Indiana Public Service Company, May 1993, regarding approval of an electric service contract with Omni Forge, Inc.

Direct Testimony before the Public Utilities Commission of Ohio on behalf of the Dayton Power and Light Company, Case No. 92-594-EL-FOR, February 5, 1993 regarding avoided cost study and appropriateness of estimates used in evaluating DSM programs. (Testimony was filed but case settled before hearings.)

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket No. 91-0335, February 25 and March 30, 1992 regarding marginal costing and marginal cost-based rates.

Direct Testimony before the Public Utilities Commission of Ohio on behalf of Cincinnati Gas and Electric Company, Case No. 91-372-EL-UNC, August 27, 1991 regarding avoided cost pricing.

Direct Testimony before the Public Service Commission of Maryland on behalf of Baltimore Gas and Electric Company, Case No. 8241, Phase II, July 19, 1991 regarding avoided cost pricing.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, Docket No. 89-0276, December 27, 1989 and January 29, 1990 regarding revenue treatment of the differential between regular and economic development rates.

Expert testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket 90-0006, December 8, 1989 regarding marginal cost rate design.

Testimony before the New Mexico Public Service Commission, on behalf of Public Service Company of New Mexico, NMPSC Case 2262, November 1, 1989 and December 8, 1989 regarding marginal costs and incentive energy rates.

Testimony before the State of Maine Public Utilities Commission, on behalf of Central Maine Power Company, Docket No. 89-68, July 31, 1989 regarding marginal costs.

Expert testimony before the State of Maine Public Utilities Commission, regarding Central Maine Power Company's Application for Fuel Cost Adjustment and Establish¬ment of Short-Term Energy-Only Rate for Small Power Producers Less Than 1 MW, on behalf of Central

Maine Power Company, Docket No. 89-80, April 14, 1989 regarding energy and capacity components of fuel clause.

Testimony before the Alberta Public Utilities Board and Energy Resource Conservation Board, on behalf of TransAlta Utilities Corporation, Docket No. RE870621, October 1987 regarding independent power producer payments.

Testimony before the Public Service Commission of Utah, on behalf of Utah Power & Light Company, Docket No. 87-035-12, August 17, 1987 regarding marginal costs.

Expert testimony before the Public Service Commission of Nevada, on behalf of Nevada Power Company, Docket No. 86-1201, February 5, 1987, regarding avoided costs.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, in *A. E. Staley Manufacturing Co. v. Illinois Power Company*, Docket No. 86-0038, September 12, 1986 and November 25, 1986 regarding standby rates.

Expert testimony before the Indiana Public Service Commission, on behalf of Northern Indiana Public Service Company, in Cause No. 38045, June 16, 1986 regarding potential for cogeneration and small power production.

Expert testimony before the Indiana Public Service Commission, on behalf of Northern Indiana Public Service Company, in Cause No. 37863, April 1986 regarding capacity credit formula for qualifying facilities (QF).

Expert testimony before the Maine Public Utilities Commission, on behalf of Central Maine Power Company, in Central Maine Power Company Cost of Service and Rate Design, Docket No. 86-2, February 14, 1986 regarding marginal costs.

Expert testimony on behalf of the Los Angeles Department of Water and Power et al., in the Bonneville Power Administration's 1985 Wholesale Rate Case, November 1984 regarding nonfirm rate design.

Expert testimony before the Superior Court of the State of California for the County of Los Angeles, on behalf of Los Angeles Department of Water and Power, in *California Manufacturers' Association, et al. vs. City of Los Angeles*, March 1984 regarding marginal cost-based rate restructuring.

Expert testimony on behalf of the Public Service Company of New Mexico, in Docket 1835, before the New Mexico Public Service Commission, February 1984 regarding marginal costs.

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Testimony before the Texas Public Utility Commission, on behalf of Houston Lighting and Power Company, in Docket No. 4712, December 1982 regarding avoided costs.

Expert testimony before the Idaho Public Utilities Commission, on behalf of Idaho Power Company, in Case Nos. U 1006 197 and U 1006 200, October 1982 regarding QF payments.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1982 Wholesale Rate Case, May 1982 regarding ratemaking objectives.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1981 Wholesale Rate Case, February 1982 regarding nonfirm rate design.

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Expert testimony before the Corporation Commission of the State of Oklahoma on behalf of the Commission, in Cause No. 27208, November 1981 regarding QF payments.

Expert testimony before the Minnesota Public Service Commission on behalf of the State of Minnesota Department of Public Service, in Docket No. E017/6R 81 315, November 1981 regarding marginal costs.

Expert testimony before the Public Service Commission of Utah on behalf of Utah Power & Light Company, in Case No. 80 999 09, March 1981 regarding marginal costs.

Expert testimony before the Colorado Public Utilities Commission on behalf of the City of Aspen, Pitkin County and Windstar Foundation, in Case No. 5970, November 1980 regarding cogeneration.

Testimony before the Idaho Public Utilities Commission on behalf of Utah Power & Light Company, in Case Nos. U 1009 107 and P 300 18, August 1980 regarding marginal cost-based rates.

Expert testimony before the Iowa State Commerce Commission on behalf of the Commission, in Docket No. RMU 80 1, July 1980 regarding marginal cost-based rates.

Expert testimony before the Board of Directors, on behalf of the Board of Directors in the 1980 Salt River Project Electric Rate Case regarding revenue requirement.

Expert testimony before the LADWP Board of Commissioners in LADWP's PURPA hearings, 1980 regarding appropriateness for LADWP's of adoption of PURPA standards.

Consulting Reports

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"Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design," July 2006, prepared for Newfoundland and Labrador Hydro.

"Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission," May 2006, prepared for Newfoundland and Labrador Hydro.

"Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies," February 2004, prepared for Manitoba Hydro.

"Survey of Electric Utility Embedded Cost Methods for Generation and Transmission in North America," December 2003, prepared for Manitoba Hydro.

"Electric Utility Use of Marginal Costs: US Case Studies," July 2003, prepared for JANUS (Tokyo, Japan).

"Review of Comments on NERC Tariff Methodology," January 18, 2001, prepared for National Energy Regulatory Commission of Ukraine.

"DP&L Report on Shopping Incentives," December 1999, prepared for Dayton Power & Light Company.

"An Introduction to System Benefits Charges," May 11, 1998, prepared for The Salt River Project.

"Analysis of the Reform of the Argentine Power Sector: Final Report," January 1998, prepared for the Ministerio de Economía y Obras Servicios Públicos, Secretaría de Energía y Puertos of Argentina.

"Development of RG&E's Fees for New Services," February 19, 1998, prepared for Rochester Gas & Electric Corporation.

"Using Capacity Contracts and Energy Savings To Estimate Marginal Generation Capacity Costs -- Contracts: They're Not Just for Lawyers Anymore," October 27, 1997 prepared for the Marginal Cost Working Group.

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"Report on An Audit of the Resource Planning Activities of the Department of Water and Power of the City of Los Angeles," December 24, 1986.

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"A Methodology for Comparative Risk Analysis: Introducing Competition into Avoided Cost Pricing," City of Houston Public Service Department, June 1984.

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"An Analysis of the Time Differentiated Marginal Costs of Central Illinois Light Company," June 1982.

"An Updated Analysis of the Time Differentiated Marginal Costs of Central Illinois Light Company," prepared for Central Illinois Light Company, December 1981.

"An Updated Analysis of the Time Differentiated Marginal Costs of Otter Tail Power Company," prepared for the Minnesota Department of Public Service, November 1981.

"An Analysis of the Costs Avoided by Oklahoma Gas and Electric Company When Energy and Capacity are Supplied by Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, September 1981.

"Summary of Concerns Expressed by Oklahoma Utilities Pertaining to Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, September 1981.

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"An Analysis of the Time Differentiated Marginal Costs of Central Maine Power Company," prepared for Central Maine Power Company, April 1981.

"Salt River Project Review of Proposed 1981 Rate Increase," prepared for the Board of Directors of the Salt River Project Agricultural Improvement and Power District, December 1980.

"An Analysis of the Time Differentiated Marginal Costs of Utah Power & Light Company," prepared for the Utah Power & Light Company, October 1980.

"An Analysis of the Time Differentiated Marginal Costs of Hawaiian Electric Company," prepared for Hawaiian Electric Company, October 1980.

"An Analysis of the Time Differentiated Marginal Costs of Idaho Power Company," prepared for Idaho Power Company, September 1980.

Presentations and Speeches

"Inter-Class Clashes Over Rising Revenue Requirements: Economic Issues," presented at Utilities Rate Case Issues and Strategies Conference, Las Vegas, NV, February 8, 2008.

"Rate Design in the Campaign for Energy Efficiency," presented at Utility Rate Case Issues and Strategies Conference, Las Vegas, NV, February 22, 2007.

"Making Every Electricity Consumer a Market Participant (Putting Demand Back in the Equation)," a presentation to the California Municipal Rates Group, Sacramento, CA, June 2003.

"Line Extension Policies in the Restructured US Electric Industry," a presentation to the Marginal Cost Working Group (MCWG), Myrtle Beach, SC, April 2001.

"Residential Electricity Tariffs: Getting the Structure Right," a presentation to the Marginal Cost Working Group (MCWG), Santa Fe, NM, October 4-6, 2000.

"Line Extension Policies – Due for a Change?" a presentation to the Marginal Cost Working Group (MCWG), Las Vegas, NV, April 3-5, 2000.

"Antitrust Concerns in Retail Access: Learning the Lingo," a presentation to the Marginal Cost Working Group (MCWG), Cambridge, MA, April 27-29, 1998.

"The Role of Securitization of Stranded Costs in a Future Competitive Electric Industry," a presentation to the Conference on Securitization of Electric Utility Stranded Costs, San Francisco, California, October 6, 1997.

"Electric Rate Structure," a presentation to the University of Florida International Training Program on Utility Regulation and Strategy, Florida, January 21, 1997.

"Is Your Contract or Rate Profitable? How Can You Tell?" a presentation to the California Municipal Rates Group, West Hollywood, California, June 25, 1996.

"Alternative Approaches for Area-Specific Marginal Transmission and Distribution Cost Estimation," a presentation to the 1994 EPRI Innovative Pricing Conference, Tampa, Florida, February 11, 1994.

"Marginal Costs: Academic Exercise or Crucial Factor in Electric Utility Decision-Making?" a presentation to the 1993 Annual Meeting of the Canadian Electrical Association, Halifax, Nova Scotia, May 18, 1993.

"Water Rates - Costing for the 90's," a presentation to the California Municipal Rates Group, San Pedro, California, February 16, 1993.

"Implementing a Dynamic Marginal Cost Study at the City of Anaheim," before the American Public Power Association, New Orleans, Louisiana, September 29, 1992.

"Estimating Hourly Marginal Costs," before the California Municipal Rates group, Anaheim, California, January 11, 1990.

"Ratesetting Using Marginal Cost at LADWP," before the California Municipal Rates Group, Winter Meeting, Anaheim, California, January 11, 1990.

March08