Exhibit No.:	
Issues:	Role of Regulation: Challenges of Today's Utility Industry
Witness:	Peter Fox-Penner
Sponsoring Party:	Union Electric
Type of Exhibit:	Rebuttal Testimony
Case No.:	EC-2002-1
Date Testimony Prepared:	May 10, 2002

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EC-2002-1

REBUTTAL TESTIMONY

OF

PETER S. FOX-PENNER

ON BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

Exhibit No. 130
Date 7/10/02 Case No. EC-2002-1
Reporter Kem

St. Louis, Missouri
May 2002

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REBUTTAL TESTIMONY

OF

PETER FOX-PENNER

CASE NO. EC-2002-1

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter Fox-Penner. My business address is 1133 20th St. NW, Washington, D.C., 20036.

Q. By whom are you employed, and what is your position?

A. I am a principal and chairman of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, Washington, and London.

Q. Please describe your educational background and experience.

A. I am an economist and manager with over two decades of experience in government and consulting, primarily in the area of regulated utilities. I began my career in 1980 as a research engineer in The Governor's Office of Consumer Services in Illinois, the precursor to the state's consumer advocate. Following graduate school, I worked from 1987-1993 as a consultant to utilities and other energy clients. In 1993, I was appointed Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy at the United States Department of Energy ("DOE"). In this position I directed (among other things) DOE's policy research program on electric utilities and served as a department liaison to state regulators and legislators on utility issues. As part of this work, I co-founded the National Council on Competition in Electricity, a joint project of the National Conference of State Legislators, the National Association of Regulatory

Commissioners Utility Commissioners, the U.S. Environmental Protection Agency, and DOE, to examine electricity competition policy issues. In 1995-1996, I worked on electricity policy issues as a Senior Advisor in the White House Office of Science and Technology Policy and as a Special Assistant to the Deputy Secretary of Energy.

Following government service, I have written and consulted on electric utility regulatory and economic issues and I frequently appear at industry seminars and association meetings. In 1997, I authored *Electric Utility Restructuring: A Guide to the Competitive Era*, a best-selling work on the subject. Schedule 1 contains a list of my recent speeches, presentations, testimony, and publications on electricity regulatory issues.

I received a Ph.D. in Economics from the Graduate School of Business, University of Chicago, as well as an M.S. in Mechanical Engineering and a B.S. in Electrical Engineering from the University of Illinois. I have testified before this Commission and the public service commissions of Illinois, Massachusetts, Florida, California, Washington, Pennsylvania, New Mexico, Kansas, and Wyoming, as well as various federal courts, the Federal Energy Regulatory Commission and the United States Congress (Senate Committee on Energy and Natural Resources and House Appropriations Subcommittees).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to portions of the testimony of Ronald L. Bible and Michael S. Proctor in light of basic regulatory principles that Commission rate determinations should be based on industry "facts and circumstances" at the time of the proceeding. My discussion occurs in two parts. First, I review the objectives of public utility regulation from an economic perspective and discuss the importance of a paradigm that provides utilities a fair opportunity to recover their costs and incentives to operate efficiently. Second, I describe how the industry and federal and state regulation have evolved over the last decade and summarize the current turmoil and uncertainty now facing the industry. Before addressing these issues in depth, however, I provide an overview of my conclusions. These are provided in the following section and in an **Executive Summary** attached hereto as Appendix A.

II. SUMMARY AND OVERVIEW OF TESTIMONY

Q. Please discuss the principal conclusions of your testimony.

A. My principal conclusions are as follows:

1) A significant deficiency in the case prepared by the Staff of the Missouri Public Service Commission ("Staff") is its failure to consider economic and regulatory conditions in the electric industry generally and in the Midwest. There is no evidence that Staff took important industry developments into account in their proposed rate filing. Indeed, Staff's case largely looks like an accounting exercise. In setting rates and returns for AmerenUE, I believe that the context in which the Company operates and its significant need for additional infrastructure are "relevant facts" that the Commission needs to consider.

2) The electric power industry has changed significantly over the last fifteen years, and this change has accelerated over the last five years. The most significant change during this entire period is the increasingly

competitive nature of the generation business. The introduction of wholesale power competition, combined with the continued regulation of transmission service and continued state regulation of generation service in at least half of the United States has created an extraordinarily complex and uncertain industry structure. Today, the electric power industry is at a crossroads between regulation and deregulation. This is the case because, in wholesale power markets, generation is widely sold on a competitive basis, whereas in many retail markets generation continues to be sold at regulated, cost-based rates.

3) Industry change and the uncertainty associated with the regulation of wholesale and retail generation markets and bulk power transmission service clearly is affecting the risk and uncertainty that vertically-integrated utilities with an obligation to serve face when they consider new investments in generation and transmission capacity. For example, even if a utility with an obligation-to-serve builds a new generating plant under traditional regulation and a state-approved resource plan, it cannot be sure how long it will have an exclusive retail franchise or marketing area. Thus, the utility cannot have a high degree of confidence that it will be able to recover its costs, through regulated rates, for the entire economic life of the plant. With regard to transmission investment, there is much uncertainty as to whether federal or state regulators will have primary responsibility for enabling transmission cost recovery. Moreover, the likely expansion of federal jurisdiction creates

uncertainty about the rate methods and formulas that will be used to recover transmission costs. State regulation needs to recognize that the risks and challenges facing electric utilities have changed and set rates and allowed returns accordingly.

4) I note that retail sales growth and increased use of its bulk power transmission system is forcing AmerenUE to make significant investments in electric infrastructure over the next 5 years. According to AmerenUE witness David Whiteley, AmerenUE plans to invest approximately $400 million over the next five years in Missouri to expand its transmission capacity and improve its import capability. AmerenUE also plans to make investments of over $2.2 billion in generation and distribution capacity over this same period.

5) A "just and reasonable" rate is one that properly strikes the key balance between the provision of reliable service at reasonable cost and adequate returns to utility investors. Regarding the latter, just and reasonable rates give a utility a fair opportunity to recover its prudently-incurred costs and to earn a return on capital that is commensurate with the return earned by other companies with comparable risks.

6) Dr. Proctor's recommendation that AmerenUE should buy power from a non-regulated affiliate at the lower of cost or market prices will make it very difficult for an affiliated generating company to earn market returns, consistent with those earned by competitive generators, on

sales to AmerenUE. This will discourage economical power trades within the Ameren system.

7) Another deficiency in Staff's case is its apparent approach towards management efficiency and rate of return, an approach that is inherently unsuited to yielding a fair rate of return and ensuring adequate investment. In addition, Staff's approach to setting the return on equity conflicts with the objective of encouraging good management performance and thus reduces AmerenUE management's incentive to perform well. Regardless of how hard they try, as long as they pass the threshold test of not being declared "poor or inept" they will earn the same ultimate return on equity or less. This is a discouraging climate for new investment, especially if industry-wide changes and risks are unusually high.

8) Historically, cost-of-service ratemaking has been the preferred method for setting electric utility rates. Cost-of-service ratemaking has been widely used, in part, because it is particularly well suited to an industry with steady, predictable sales growth and constant or slightly declining costs. Today, however, some electric utility costs, such as purchase power costs, are more volatile than they were in the past. The changed industry environment has created numerous—and increasingly complex—opportunities for utilities to control costs and improve other aspects of their performance. For these and other reasons, the drawbacks of cost-of-service regulation are more significant today than they were in

the past. Hence, there is increased interest among regulators in establishing alternative ratemaking methods that give utilities a stronger incentive to improve performance.

9) The primary alternative to cost-of-service regulation is a set of ratemaking methods commonly known as incentive regulation. Incentive regulation differs from cost-of-service regulation in that it partially decouples a regulated firm's rates from its costs and uses explicit financial incentives to motivate the firm's behavior.

Q. Please elaborate upon the first significant deficiency in Staff's case, their neglect of fundamental changes in utility industry regulation and structure.

A. All regulatory proceedings occur against an important backdrop of industry economic and regulatory conditions, as well as other possible changing factors. The electric utility industry today faces greater turmoil and uncertainty than it has since the 1930s, as it stands at a crossroads between regulation and deregulation. Changes in laws and regulatory policies over long, uncertain periods have increased industry risk and made regulation and utility management a challenging endeavor.

Often conflicting changes are occurring at a dizzying pace in this industry. A recent front-page article of the Wall St. Journal summarizes these changes as follows:

> . . . Now, with the power industry hovering uneasily between regulation and deregulation, it faces the prospect of a market that combines the worst features of both: a return to government restrictions, mixed with volatility and price spikes as companies struggle to meet the nation's future energy needs.
>
> Investors and lenders, spooked by the twin specter of California and Enron, have become less likely to commit capital to building new power plants, transmission lines and natural-gas pipelines. The U.S. will require big additions to its power

> production and distribution capacity when it emerges from the current recession—but for now, at least, the nation's capital markets are reluctant to cough up the necessary funds.
>
> Responding to the dramatic decline in their stock prices and the recession, energy companies are retrenching. Calpine Corp., one of the most aggressive players in the deregulated market, is waffling on previously announced plans to build billions of dollars in new power plants. Virginia-based AES Corp., which has missed its recent earnings targets, has scaled back its expansion goals and is selling some of its foreign assets. Northeast Utilities is curtailing plans to builds a 30-mile undersea transmission line from Connecticut to Long Island.
>
> Meanwhile, regulators are racing to place new guardrails on the U.S. power market. The federal government is trying to beef up its market-surveillance activities. And it also is trying to broker deals between states that might make interstate energy transmission faster, cheaper and easier.

I attach the complete article I reference here in Schedule 2.

Q. Please elaborate upon the second major deficiency in Staff's case, pertaining to the relationship between sound management and allowed return.

A. Staff witness Bible says that the allowed return should not insulate a company's financial performance against "poor or inept" management. (Bible, p. 6). However, no Staff witness asserts or suggests that Ameren's recent management performance has been poor or inept.[1] Thus, Staff's logic suggests that Ameren's allowed rates and returns should be above those that would result following management error or adverse events. However, Staff's approach to ratemaking seems to be the following: examine the actual earnings of AmerenUE and remove all earnings that, with hindsight, yield returns above the allowed level. Thus, regardless of whether management does (1) extremely well, producing high earnings; (2) moderately well, producing earnings

[1] In fact, recent statements issued by Standard & Poor's concerning Ameren's and Union Electric's credit quality commend the Company's management performance.

slightly above allowed earnings, or (3) just well enough to achieve precisely their allowed earnings, the ultimate outcome is the same: all "excess earnings" are reduced as quickly as possible and the Company earns only its allowed return at best. This approach to ratemaking creates asymmetric risks and rewards for AmerenUE and thus over time tends to yield an actual realized average return on equity below the allowed return on equity.

Q. How is the remainder of your testimony organized?

A. Section III of my testimony reviews the objectives of utility regulation from an economic perspective and discusses the importance of a paradigm that provides utilities a fair opportunity to recover their costs and incentives to operate efficiently. In Section III, I also describe cost-of-service ratemaking and explain why it had become more problematic due to the changes occurring in the electricity industry. Section IV describes how the industry and federal and state regulation have evolved over the last decade and summarizes the current turmoil and uncertainty now facing the industry. I also show that the increased risk and uncertainty resulting from these changes occurs at a time when AmerenUE needs to make significant new investment in generation and transmission capacity. Finally, I explain why it is in improper to ignore these industry changes in this rate proceeding.

III. ROLE OF UTILITY REGULATION FROM AN ECONOMIC POLICY PERSPECTIVE

A. OBJECTIVES OF PUBLIC UTILITY REGULATION

Q. Have Staff witnesses appropriately considered the objectives of sound regulation in their testimony and rate recommendation?

A. No. Staff's case is not consistent with some of the principles of sound regulation. For example, Staff's rate recommendation imposes asymmetric risks and rewards on AmerenUE, as I will show later in this section.

Q. What are the overriding goals of regulation?

A. The primary goal of electric utility regulation is to ensure the efficient and non-discriminatory provision of reliable electric service at reasonable rates. Regulation is a substitute for competition for electric services that cannot be provided competitively or where competition is inadequate. The establishment of reasonable rates (and related policies) requires that regulators balance the need to protect utility customers from unreasonable prices or inadequate service with the need to give utility investors a fair opportunity to earn compensatory returns. Important additional objectives of sound regulation include an efficient rate structure, reasonable rate stability, facilitation of energy efficiency and other public policy objectives, protection of low-income customers and others for whom power is a necessity, and the facilitation of performance gains and investments necessary for reliable and adequate service at reasonable cost. Clearly, this means that utility rates (and their associated returns) must fulfill several roles at once.

Q. Staff witness Bible claims that AmerenUE has "monopoly power" (Bible, page 3). Is this correct?

A. No. Mr. Bible's assertion that AmerenUE has "monopoly power" (by which, I assume he means that AmerenUE has "market power") is incorrect. AmerenUE has a monopoly franchise but it does not have market power, as is evident from a brief review of the standards used by the U.S. antitrust agencies (and others) to identify the presence of market power.

The two types of market power that firms can exercise are horizontal market power and vertical market power. Horizontal market power generally is defined as the ability of one firm or a group of firms to sustain and profit from a price increase above competitive levels. Such market power typically is exercised through physical or economic withholding of supply. Vertical market power refers to the ability of a vertically integrated firm, *i.e.*, one with an interest in both an upstream and downstream market, to take actions at one level of the production process to adversely affect prices or output at another level. For example, the price or supply of electric generation could be affected by the exercise of market power in the (upstream) markets for coal, natural gas, or other fuels.

AmerenUE clearly does not have market power because it cannot set the retail price for electricity. Instead, this power to set prices is reserved solely for this Commission. Moreover, AmerenUE is prohibited from withholding supply (or failing to serve load) under its franchise agreement. In short, the entire purpose of utility regulation is to ensure that utilities with legal monopoly service areas do not have the power to set prices.

Q. What is the economic standard for just and reasonable rates?

A. A "just and reasonable" rate is one that properly strikes the key balance between the provision of reliable service at reasonable cost and adequate returns to utility investors, taking into consideration the above objectives. Regarding the latter, just and reasonable rates give a utility a fair opportunity to recover its prudently-incurred costs and to a earn a return on capital that is commensurate with the return earned by other companies with comparable risks.

Q. Is this economic standard also consistent with the legal standard for just and reasonable rates and a fair return on investment?

A. Yes. Two landmark U.S. Supreme Court cases, the Bluefield and Hope cases, define the legal principles underlying the regulation of a public utility's rates and provide the foundations for the notion of a fair and compensatory rate of return.[2] Bluefield and Hope established three related standards of fairness and reasonableness of the allowed rate of return for a public utility: (1) capital attraction; (2) comparable earnings; and (3) financial integrity.

Q. Please explain the economic logic underlying these standards for compensatory rates of return.

A. The economic logic underlying these standards is straightforward. There is an opportunity cost associated with the funds that capital suppliers provide to a public utility. That cost is the expected return foregone by not investing in other firms with corresponding risks. Thus, the expected rate of return on a public utility's debt and equity capital should equal the expected rate of return on the debt and equity of other firms having comparable risks. This is a "fair" return, and one that will enable the utility

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[2] Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391. 1944)

to maintain its credit so that it continues to have access to the capital markets to raise the funds required for investment. It also is a prerequisite for economically efficient prices that better allocate society's total resources.

Since the price charged by utilities is set by regulators, a utility makes investments on the presumption that it will, through sales at regulated rates, have a reasonable opportunity to recover the cost of, and earn a fair return on, its investments. Investors would be unwilling to fund a utility's investments, or would require a large risk premium to do so, if they were not confident that regulators would set the utility's rates in a way that gave the utility a fair opportunity to recover its costs. One simply cannot expect investors to invest in a rate-regulated company without a fair opportunity to earn their risk-adjusted cost of capital. The rebuttal testimony of Dr. Roger A. Morin and Ms. Kathleen McShane elaborate on these standards.

Q. What are the potential consequences of rates that provide an inadequate return to a utility?

A. A utility earning inadequate returns will have a hard time raising capital and therefore will find it difficult or very costly to make sufficient investment in generating plant and other needed infrastructure. Inadequate investment will cause costs to increase in the future and may also lead to lower service quality and reliability. Moreover, inadequate earnings will make it difficult for the utility to attract and retain talented staff and will make management overly risk averse. The short-term customer benefits of lower rates, based on an inadequate return, likely will be more than offset by a high future cost of capital, inadequate infrastructure, and less efficient utility operations in the long-term.

In the long-term, the utility's costs ultimately will increase and/or its service will decline. Its costs also may increase for other reasons, such as increased plant outages and over reliance on purchased power (due to the inability to self-build).

Q. Do just and reasonable rates "guarantee" a utility full recovery of its costs, including a fair return on its capital?

A. No. Just and reasonable rates do not guarantee an electric utility a specified level of earnings or a certain rate of return. Electric utilities traditionally bear certain risks, such as the risk of lower than expected sales due to a national or local economic downturn or unexpectedly mild weather. Utilities also are subject to prudence reviews and potential downward adjustments to their recoverable costs based on a finding of imprudence. In Missouri, for example, electric utilities also bear the risk of changing fuel costs and volatility in wholesale power markets.

However, such downside risks need to be balanced with appropriate upside opportunities. Utility shareholders will not have a reasonable opportunity to earn a fair return on their investment if the utility is penalized for poor investments, through prudence disallowances, but not rewarded for good ones. Regulation that creates a "heads I win tails you lose" environment does not yield just and reasonable rates and returns. Fair regulation also requires that the rules governing ratemaking and cost recovery not be applied in an arbitrary and inconsistent manner.

Q. Please explain the concept and implications of asymmetric risks and rewards.

A. In general, a utility faces asymmetric risks and rewards if it is subject to financial penalties for poor outcomes but is not able to earn corresponding financial rewards for superior outcomes. A simple example will help to illustrate this. Assume a utility with an allowed return on equity ("ROE") of 12 percent. This utility will face asymmetric risk if it is permitted to earn its allowed 12 percent ROE *only* on good (*i.e.*, economical) investments but is provided no return on equity on "poor" investments (*i.e.*, investments that are not economical with the benefit of hindsight). In this situation, the very best that the utility can do is to earn its allowed ROE (if all its investment are economical). If the utility makes any "poor" investments, it necessarily will earn less than its allowed ROE. Since no utility (or any company, for that matter) will be successful with all of its investments, the utility's *expected* ROE will be less than its allowed return of 12 percent, because of the likelihood that some of its investments will not be economical in hindsight. Such rate regulation is asymmetric because it affords the utility no opportunity to offset the losses it incurs on poor investments with returns higher than 12 percent on good investments.

This same logic applies to regulatory treatment of management performance. Suppose that a utility is permitted to earn its allowed ROE of 12 percent if its management performance is deemed to be average or better, but is provided a lower return if its management performance is deemed to be poor. The risks and rewards are asymmetric because the very best the utility can do is to earn its allowed return of 12 percent, even if its management performance is judged by regulators to be excellent. The utility is given no opportunity to offset lower earnings during periods when its management performance is judged to be poor with higher earnings during periods when its performance is deemed to be good or excellent. Once again, the utility's average actual ROE over time will be lower than its allowed return.

Rate regulation that provides asymmetric risks and rewards of this type is not just and reasonable. It also is poor public policy because it creates an overly risk-averse management culture that can hinder innovation and superior performance. Proper regulation balances downside risks with appropriate upside opportunities.

Q. Does Staff's case impose asymmetric risks and rewards on AmerenUE?

A. Yes, I believe that Staff's proposed rate filing imposes asymmetric risks and rewards on AmerenUE that would make it difficult for the Company to earn its allowed rate of return over time. Such asymmetric risks and rewards are implicit in the recommendations of Staff witnesses Bible (Bible, pp. 6-7) and Proctor (Proctor, pp. 18-19).

Q. Please identify the recommendation of Mr. Bible that at least implicitly impose asymmetric risks and rewards on AmerenUE.

A. On page 6 of his testimony, Mr. Bible says that ratepayers should not be forced to bear the brunt of "unnecessarily" high costs that result from poor or inept utility management. Precisely what Mr. Bible means by this is unclear, but he seems to be saying that a prudence disallowance should equal the amount of the harm (*e.g.*, if regulators determine that a utility spent $1 million more on generation operation and maintenance than it should have, the utility's revenue requirement is reduced by $1 million). At the same time, Mr. Bible does not recommend that a utility be permitted to keep some or all of the benefits resulting from superior management. This ratemaking approach creates asymmetric risks and rewards similar to those set forth in the preceding hypothetical. It would be very difficult for AmerenUE to earn its allowed rate of return over time if the Company always had to bear the full harm of poor management decisions but was unable to reap the benefit of good management decisions.

Q. Please identify the recommendations of Dr. Proctor that at least implicitly impose asymmetric risks and rewards on AmerenUE.

A. On pp. 17-19 of his testimony, Dr. Proctor criticizes AmerenUE's summer 2001 purchase of 450 megawatts ("MW") from Ameren Energy Marketing ("AEM"), the marketing representative for Ameren Electric Generating Company ("AEG").[3] Both AEM and AEG are affiliates of AmerenUE. AmerenUE purchased this power at a market-based rate that was approved by the Federal Energy Regulatory Commission ("FERC"). Dr. Proctor says that AmerenUE's purchases of energy and capacity from AEG, AEM, or any other non-regulated affiliated company always should be made at the lower of cost or the market price.

Q. Is there an inherent problem with AmerenUE buying power from AEG/AEM at a market-based price?

A. No. There is nothing inherently wrong with an electric utility purchasing power from an unregulated affiliate at a true market-based price. As I will explain in the next section of my testimony, market-based prices have become much more common in wholesale power markets over the last five years. The FERC regulates the price of wholesale power sales, including sales between affiliated companies. FERC recognizes that transactions between regulated public utilities, such as AmerenUE, and an affiliated power marketer, such as AEM, raise concerns of cross-subsidization, self-dealing, and

[3] AEG is the company that now owns the generating assets of Central Illinois Public Service Company.

market power gained through the affiliate relationship.[4] However, the FERC has established several ways in which a utility can show it has not unduly favored an affiliate, including (1) evidence of direct head-to-head competition between the seller and competing unaffiliated suppliers in either a formal solicitation or an informal negotiation process and (2) benchmark analysis, showing that contemporaneous sales of similar products in the relevant market were at a comparable (or higher) price.[5] The FERC found no evidence of affiliate abuse and therefore approved the summer 2001 power sales agreement between AmerenUE and AEM.

Mr. Proctor's apparent blanket opposition to AmerenUE purchasing power from AEM at market prices (unless such prices are shown to be lower than AEM's cost) is not consistent with federal energy policy and ignores the tests and safeguards that the FERC uses in its review of such transactions.

Q. What are the likely economic ramifications of Dr. Proctor's proposed treatment of AEG/AEM sales to AmerenUE?

A. Dr. Proctor's recommendations, if implemented, clearly would discourage sales from AEG/AEM to AmerenUE. Dr. Proctor would permit AmerenUE to purchase from AEG/AEM only if they did so at the lower of market or cost-based prices. However, any seller in a changing market who was forced to sell at the lower of cost or market would, on average, fail to earn a market-determined rate of return. On transactions where that seller's cost was less than the prevailing market price, she would be paid less than market and therefore earn less on that transaction than the prevailing

4 See FERC order conditionally accepting for filing proposed power sales agreement and granting, in part, confidential treatment, Docket No. ER01-1810-000, June 14, 2001, p. 5.

5 *Ibid*

market return. On transactions at market price the seller would, on average, earn fair market returns. When the portion of sales at cost are averaged in with the portion of sales at market, the overall average profitability is below market levels.

Moreover, competitive (i.e., non-rate regulated) generation is a riskier investment than generation built under cost-of-service regulation. Since Ameren's shareholders bear the risk of competitive generation investments, they naturally will seek to maximize the revenues earned from such investments. A revenue-maximizing strategy may or may not result in sales from AEG/AEM to AmerenUE. However, Dr. Proctor would largely foreclose this option.

Foreclosing AEG/AEM as a potential supplier would reduce AmerenUE's supply options. Moreover, Ameren's generating resources could become needlessly balkanized because AEG/AEM almost always will be financially better off selling its available energy and capacity off-system rather than to AmerenUE. This will not facilitate economical utilization of Ameren's generation as a general matter and could cause serious problems in a "tight" (*i.e.*, capacity constrained) wholesale power market. For example, in a tight market with relatively high market prices, the last party that AEG/AEM would want to sell power to is AmerenUE—even if AmerenUE badly needed the power.

Dr. Proctor and Commission Staff could argue that AmerenUE should never let itself get in a position where it needs to purchase capacity to have adequate installed and operating reserves. This, however, is unrealistic. Unexpected changes in weather, economic conditions, plant availability, and delays in construction always create the opportunity for a utility to be temporarily short of capacity. Moreover, striving to always be "long" on installed capacity carries its own distinct regulatory and financial risks. Commissions can and have made cost disallowances for "excess" generating capacity.

Q. Should the MPSC reject Dr. Proctor's recommendation that AmerenUE purchase power from AEG/AEM at the lower of cost or market?

A. Yes. Sales from AEG/AEM to AmerenUE at market prices should be permitted. Allowing market-based sales will avoid the balkanization of Ameren's generating assets and facilitate economic trades between the Ameren companies. It also will give AEG/AEM a fair opportunity to earn to earn market-determined returns, consistent with those earned by competitive generators, on sales to AmerenUE.

B. RATEMAKING METHODS

Q. What has been the most common ratemaking method used to achieve just and reasonable rates in the electric utility industry?

A. In the early years of utility regulation, many approaches were tried. For many reasons, regulators ended up adopting "cost of service" ratemaking. Under this approach, a utility computes its total costs of service, including actual investment costs and an estimated risk-adjusted return on investment. This yields an annual "revenue requirement." When this annual revenue requirement is divided by estimated sales, an estimated "cost-based rate" is obtained. This rate is the lowest possible average rate the utility can charge and still earn enough to pay all its suppliers and compensate investors fairly.

Cost-of-service ratemaking has been widely used, in part, because it is particularly well suited to an industry with steady, predictable sales growth and constant or slightly declining costs. This is because cost-of-service ratemaking, as practiced in Missouri and other states, bases rates either on historical costs and sales (a "historical test year," adjusted for known and measurable changes in costs), or projected costs and sales (a "future test year"). A utility's actual costs and sales always will vary somewhat from the values used to set its rates, but this is not a problem as long as costs and sales are relatively constant or are changing in a steady, predictable way. From the end of World War II until the mid-1970s, the electric utility industry in general experienced both steady sales growth and steadily declining costs. Costs declined, in part, due to pervasive economies of scale in power generation. As a result, electric utility rates also declined over this era. Cost-of-service ratemaking was a good fit for the electric industry during this period because rates reflected the steady and predictable changes in utility costs and sales.

Today, however, some electric utility costs and sales are much more volatile than they were in the past. In Section IV of my testimony I will describe how the price and volume of wholesale power has become more volatile over the last five years as a result of increased competition and the evolution from cost-based rates to market rates in wholesale power markets. We now are in a world where an electric utility's costs vary more unpredictably than they did in the past. Thus, in today's electric power industry, cost-of-service ratemaking requires more judgement and analysis from state regulators than it did in the past.

Q. Earlier, you noted the multiple objectives of public utility regulation. Have non-cost factors been taken into consideration in cost-of-service ratemaking?

A. Yes. The explicit consideration of factors other than cost is important because cost-of-service ratemaking, in and of itself, does not necessarily ensure the provision of adequate and reliable service or encourage efficient utility performance. In addition, cost-of-service ratemaking does not always yield reasonably stable rates and does not ensure an efficient and equitable rate structure. State regulators have long recognized the importance of these additional factors and have considered them in the rate making process. Cost-of-service ratemaking combined with the consideration of these additional factors has been referred to as the "traditional regulatory model."[6]

Q. How can regulators encourage efficiency and superior performance under cost-of-service ratemaking?

A. Under the traditional regulatory model, regulators can encourage efficiency and superior rewards through the careful use of "regulatory lag" and careful evaluation of management decision making. For example, regulators can allow utilities to retain some of the benefits associated with increased efficiency and superior performance by extending the period between rate cases and by rewarding good performance with higher allowed rates of return. Since determining the fair rate of return is not an exact science, regulators can, in setting this rate, explicitly or implicitly make an allowance for the relative efficiency or inefficiency of a utility's operation.

[6] For example, see the Final Report of the Missouri Energy Policy Task Force, issued October 16, 2001, at p. 44.

Q. If the commission can choose among alternative approaches to setting rates that are just and reasonable, are there any advantages to one approach over another?

A. Yes, there are. It is very important to understand that any approach to ratemaking inevitably creates financial incentives for a regulated company. Cost-of-service regulation generally does not provide strong incentives for efficient operation or cost minimization because rates are closely tied to costs. When a utility's costs increase, its rates increase (at the conclusion of the next rate proceeding) by a commensurate amount, and *vice versa*. Moreover, cost-of-service regulation also can, under certain conditions, provide utilities an incentive to expand their investment (*i.e.*, rate base) inefficiently.

This combination of weak incentives to control costs and potentially strong incentives to over invest in rate base was not viewed as particularly troublesome in the industry until the 1970s. Until then, the aggressive expansion of rate base was viewed positively because more investment often translated into better service and lower rates via industry-wide economies of scale and scope. The declining costs resulting from economies of scope and scale made regulators less concerned about other aspects of utilities' performance. Furthermore—as explained above—cost changes were more predictable, facilitating relatively less complex and less frequent rate proceedings.

Today, however, these conditions no longer apply. Over the course of the last 25 years, changing technology has limited the cost savings available from the simple economies of scale in generating plants. Since then, but particularly in the last 5 years, the changed industry environment has created numerous—and increasingly complex—

opportunities for utilities to control costs and improve other aspects of their performance. For these and other reasons, the drawbacks of cost-of-service regulation are more significant today than they were in the past. Hence, there is increased interest among regulators in establishing alternative ratemaking methods that give utilities a stronger incentive to improve performance.[7]

Q. Please identify the ratemaking methods that potentially give utilities a stronger incentive to improve performance than cost-of-service regulation.

A. The primary alternative to cost-of-service regulation is a set of ratemaking methods commonly known as incentive regulation or performance-based regulation. Incentive regulation differs from cost-of-service regulation in that it partially decouples a regulated firm's rates from its costs and uses explicit financial incentives to motivate the firm's behavior. Under cost-of-service regulation, there is in principle a dollar-for-dollar correspondence between prudently-incurred costs and rates. Under incentive regulation, the link between costs and rates is not as direct in the short term. Broad-based incentive regulation generally is seen as a logical, evolutionary step from the traditional regulatory model.

Q. Please define the common types of broad-based incentive regulation.

A. Price cap regulation, rate freezes, rate case moratoria, and earnings sharing plans are among the most popular forms of broad-based incentive regulation. Under price-cap regulation, a utility is permitted to adjust its rates on an annual or periodic basis

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[7] Modern economics also considers the impact of information asymmetry between the regulated firm and its regulators. When there is a high degree of change and volatility in the industry, it is difficult for regulators to distinguish between purely unintentional adverse outcomes and obvious poor management. Where this is difficult, economic incentives can be more effective than regulation in providing performance incentives.

according to a pre-determined formula. Such formulas typically allow rates to increase at the rate of inflation less a productivity offset. Under a rate freeze, the company cannot change any of its rates for a specified period. Under a rate case moratorium, rate cases designed to systematically increase or decrease rates are not permitted, but some individual rate elements may be changed. Earnings sharing plans implement explicit sharing of realized earnings between the regulated firm and its customers. Customers typically are awarded (either through direct financial payments or lower rates) a share of the company's achieved earnings in excess of a pre-determined threshold return. Earnings sharing plans often are employed in combination with rate freezes, rate case moratoria, or price caps. A primary purpose of earnings sharing is to align company and consumer interests and to keep a company's earnings at politically and operationally acceptable levels during the plan's term or commitment period.

The attributes, potential benefits, and evolution of incentive regulation in the United States are discussed at length in the rebuttal testimony of Dr. Dennis Weisman.

Q. Does Staff's case consider or propose alternative or incentive ratemaking for AmerenUE?

A. No. Staff does not even consider, much less recommend, alternative or incentive ratemaking for AmerenUE. The failure to even consider alternative or incentive ratemaking is an important deficiency in Staff's case, given the changes occurring in the electricity industry. I find this omission even more puzzling given the fact that from July 1, 1995 through June 30, 2001, AmerenUE was regulated under a form of incentive regulation known as the Experimental Alternative Regulation Plan

("EARP"). The EARP is described and discussed at length in the rebuttal testimony of Dr. Dennis Weisman.

IV. REGULATION NEEDS TO RECOGNIZE THE CHALLENGES OF TODAY'S ELECTRIC UTILITY INDUSTRY

A. CHANGES IN ELECTRIC GENERATION AND TRANSMISSION

Q. Does Staff's case acknowledge or account for the challenges facing companies like AmerenUE in today's increasingly competitive electric power industry?

A. No. Staff's case does not acknowledge the important changes occurring in the electric power industry or the significant uncertainties that electric utilities are facing. Staff's apparent obliviousness to these significant changes and uncertainties is apparent in the remarks of Mr. Bible. In his November 2001 deposition, Mr. Bible conceded that he was unfamiliar with recent developments in wholesale power markets and with landmark federal initiatives to increase competition in these markets, such as the Energy Policy Act of 1992, and FERC Orders 888 and 2000.[8] (I discuss each of these federal initiatives below.)

Q. Why is Staff's failure to consider these developments relevant to this proceeding?

A. Ratemaking should not be conducted in a vacuum. Rates and the allowed rate of return should reflect the risks, challenges, and uncertainties facing AmerenUE. They also should reflect AmerenUE's need to raise capital to build the additional

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[8] Bible deposition, pp. 123-124.

capacity needed to provide adequate, reliable, and economical service to its native load. I elaborate on these and related points in this section.

Q. You noted earlier that the electric utility industry has changed significantly over the last fifteen years. What is the most significant change in the utility industry?

A. Without question, the most significant change in the electric utility industry over the last fifteen years is the increasingly competitive nature of the generation business. As I will explain further, the recent introduction of wholesale power competition, combined with the continued regulation of transmission service and continued State regulation of electric generation service in at least half of the United States has created an extraordinarily complex and changing industry structure.

Until the mid to late 1980s, most generation was built by vertically-integrated utilities under cost-of-service regulation. Similarly, wholesale power generally was sold under cost-based rates set by the FERC. Since that time, the construction of new generating capacity has become a largely market-based business across much of the U.S.[9] This development, in combination with utility divestiture of existing generating plants to competitive suppliers, is increasing the portion of U.S. generation sold on a competitive basis significantly. According to the U.S. Energy Information Administration ("EIA"), competitive power suppliers now provide about 30 percent of total U.S. electric generation. Moreover, competitive suppliers are dominating the construction of new capacity. In 1998 alone, 82 percent of new generating capacity was

[9] By "market-based," I mean that the plant's output generally is sold under negotiated, market-based rates instead of regulated prices. Generating plants selling energy and capacity under market-based rates still may be subject to wholesale price caps in certain circumstances.

provided by non-utilities. EIA projects that over the next few years competitive suppliers will build over three times as much new generating capacity as traditional utilities.

In the last five years, "market-based" sales of wholesale power--from both new and existing generating capacity--have become much more prevalent. Market-based power sales are so prevalent in wholesale generation markets today that daily "spot price" indices now are quoted for numerous locations throughout the U.S., including several locations in the Midwest.[10] Another manifestation of the changing power market is the availability of futures contracts, which are a standardized form of a forward contract that allows buyers and sellers to "lock in" a price for power at a specified trading hub for a given future delivery date.[11] In summary, the price at which generation is sold, in daily, short-term, and long-term transactions has become much more market driven.

Q. Why did generation become more competitive?

A. The economic and structural change in the electric generation sector is the result of technological and economic changes combined with two major legislative enactments and a number of federal and state regulatory initiatives. As a result of technological and economic changes, electric generation is no longer believed to be a "natural monopoly." In other words, there no longer is any evidence that, in any one area of the country, a single firm can generate power more cheaply than several competing firms. As soon as this observation became widely accepted, the rationale for natural-

[10] *Platts*, for example, quotes daily spot prices for seven locations in the Midwest: (1) Northern ECAR; (2) Into Cinergy; (3) Northern MAIN; (4) Southern MAIN; (5) Into ComEd; (6) Northern MAPP; and (7) Southern MAPP. Prices are for pre-scheduled, daily on-peak (16-hour) electricity in $/MWh.

[11] Futures contracts essentially are financial "hedges" and usually do not result in the physical delivery of electricity.

monopoly-style regulation of generators disappeared—though importantly, transmission and distribution continue to be viewed as natural monopolies. The end of scale economies in generating plants has sent the industry and its regulators on a search for the best way to harmonize competitive generation with a regulated transmission and distribution system—a search that is far from finished today.[12]

Q. You mentioned two major legislative enactments. What was the first major legislation that encouraged the development of competitive generation markets?

A. The introduction of competition to the generating sector began in 1978, when the Public Utility Regulatory Policies Act ("PURPA") was signed into law. Section 210 of PURPA encouraged the development of "cogeneration" and "small power production" facilities.[13] Electric utilities were required to purchase energy and capacity from such facilities, known collectively as qualifying facilities ("QFs"), at a price equal to the utility's "avoided cost." In addition, QFs were exempt from much of the financial and rate regulation that applied to other generators.

As a result of technological advances in gas turbines and the broader availability of natural gas, PURPA ended up launching a vibrant new industry known as the independent power industry. During the 1980s alone, more than 20,000 MW of QF capacity were built and put into operation, roughly the equivalent of 20 large nuclear or coal-fired plants. This figure was much larger than anticipated by any of the creators of

[12] A second driver for generation deregulation was the phenomenon of power plant cost overruns and regulation's difficulty in dealing with them. I discuss this in my 1997 book at page 14.

[13] Cogeneration facilities simultaneously produce electricity and steam. Small Power Production facilities can be no larger than 80 MW and have to use a waste or renewable fuel source as their primary fuel input.

PURPA.[14] By the late 1980s, the apparent abundance of QF capacity, coupled with concerns about the accuracy of administratively-determined prices for QF power, caused some states to procure new QF generating capacity (and in some cases non-QF capacity) through competitive bidding.[15]

Q. What was the second major legislative enactment that encouraged the development of competitive generation markets?

A. The second major legislative initiative that fostered the development of competitive generation markets was the Energy Policy Act of 1992 ("EPAct"). Title VII of this law created a new, much broader class of wholesale generators that, like QFs, were largely exempt from financial and rate regulation. Title VII also gave the FERC explicit authority, on a case-by-case basis, to order the provision of transmission service to a wholesale buyer or seller. In passing EPAct, Congress was seeking to further the development of non-utility generation. PURPA clearly had spurred the development of non-utility generation, but its benefits were limited to a narrow range of technologies (*i.e.*, cogeneration and small power production). EPAct, in effect, freed the independent power industry from the technological constraints of PURPA and, through its transmission access provisions, began to give generators the opportunity to sell their output to a wholesale buyer other than the local utility.

Q. What regulatory initiatives spurred the development of competitive generation markets?

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[14] *Analysis of Options to Amend the Public Utility Holding Company Act of 1935*. National Energy Strategy, Technical Annex 1, 1991, pp. 12-13.

[15] *Ibid.*, pp. 14-15.

A. Since the late 1980s, the FERC has taken a series of initiatives to foster the development of competitive wholesale power markets. These actions primarily were focused on expanding generators' access to the transmission grid because such access is an absolute pre-condition to effective competition in power generation.

In 1996, the FERC issued Order No. 888, which required all jurisdictional transmission-owning utilities (such as AmerenUE) to file open access transmission tariffs and to functionally "unbundle" transmission service from their merchant generation function. As Order No. 888 was implemented and open transmission access became widespread, FERC also became more willing to permit market-based pricing of generation sales on a broad, regional basis. In regions of the U.S. with operating Independent System Operators ("ISOs"), virtually all generation (including some ancillary services) is sold at market-based rates.

To further facilitate competitive wholesale generation markets through improved transmission service, the FERC's principal electric policy goal currently is the establishment of large regional transmission organizations ("RTOs") and a "standardized" wholesale market design. FERC Order No. 2000, issued in December 1999, strongly encouraged all jurisdictional transmission-owning utilities to join an operational RTO by December 15, 2001. While this deadline has been relaxed, the FERC continues to see RTOs as a key building block to the development of robust regional power markets. In particular, the FERC believes that appropriately designed RTOs could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices;

(4) improve market performance; and (5) facilitate lighter handed regulation.[16] AmerenUE is, of course, a member of the Alliance, which has been directed by the FERC to join with the Midwest ISO to help form one large RTO across the Midwest. In addition, the FERC is widely expected to issue a major rulemaking creating a new network service tariff common to all markets and a requirement that all RTOs design and operate their markets according to a model that is based generally on the PJM RTO.

Q. How has State regulation evolved in response to the changes in the electric generation sector?

A. As wholesale power markets have become more competitive, state regulators and policymakers now face the threshold issue of whether to extend competition to state-jurisdictional retail electric markets. Indeed, the most significant development that occurred in state regulation over the last decade was the implementation of retail access and customer choice. Today, eighteen states and the District of Columbia have opened at least a portion of their retail electric markets to competition.[17] Virtually every state in the U.S. has at least studied the possibility of adopting customer choice.

Some of the states that implemented retail access (*e.g.*, California, Massachusetts, and Maine) required or strongly encouraged their jurisdictional electric utilities to divest some or all of their generating assets. In states with retail access but without such mandates, some utilities voluntarily decided to sell their generating assets.

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[16] FERC Order No. 2000, p. 3.

[17] The states that currently permit at least some retail customers to choose their electric supplier are Arizona, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Nevada, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia. California recently closed its retail market to alternative electricity providers.

Over the last five years, voluntary and involuntary sales of generating assets have significantly increased the amount of merchant generating capacity in the U.S.

Q. What has been the result of retail access?

A. To date, the results of retail access have been mixed at best. California and several other western states have abandoned or delayed retail access due to the large and sustained increase in wholesale prices that started in the summer of 2000 and lasted through May 2001. Other states, notably Pennsylvania, believe that retail access has been a success and has led to significant customer savings. In my judgement, only very limited analysis of the costs and benefits of retail competition is available, which makes it difficult to evaluate the claims of its supporters and its detractors.

Q. Will the partial retreat from and reassessment of retail competition jeopardize the evolution toward wholesale competition?

A. Probably not, for several reasons. First, the FERC is fully committed to the development of competitive regional wholesale power markets, and there is at least tacit agreement in Congress to support this. There are some differences among the FERC Commissioners on how to best achieve this goal (*e.g.*, how aggressive should the FERC be in prodding the formation of large RTOs), but there is no disagreement on the desirability of this goal. Second, there is a significant amount of generating capacity under construction and development throughout the U.S., and most of it is being built by merchant generators that have no franchise customers or native load and expect to sell the plant's output at market-based prices.[18] Under any foreseeable scenario, partially

[18] This does not necessarily mean that their output will be sold into the spot market. I fully expect merchant generators to sell a portion or possibly all of their capacity under forward contracts. Such contract prices will, however, be a negotiated, market-based price.

unregulated generators will sell wholesale power in large regional markets and will comprise the majority of power supply in the Unites States.

B. OVERVIEW OF TODAY'S BULK POWER MARKET IN THE MIDWEST

Q. Please describe the general structure of the Midwestern bulk power market.

A. The Midwest bulk power market has become increasingly competitive in the last five years and currently features decentralized, "bilateral" trading among many buyers and sellers, including vertically-integrated utilities, marketers, and merchant generators. Until recently, transmission service generally was provided on a company-specific basis by vertically-integrated utilities. This is changing, however, now that the Midwest has one operating RTO—the Midwest ISO—which began providing transmission service in February 2002 after being approved by the FERC in December 2001. The Midwest ISO provides transmission service over a broad region that spans 15 states and parts of Canada. The other proposed Midwestern RTO, the Alliance RTO, has been directed by the FERC to become a part of the Midwest ISO in some fashion. The Midwest currently does not have a centralized power exchange comparable to those in operation in the northeastern U.S. or in some other countries that have restructured their electric utility industry but will need to establish one under the FERC's proposed standard market design.

Q. How does the increasingly competitive Midwestern wholesale generation market affect electric utilities such as AmerenUE?

A. The increasingly competitive generation market affects utilities like AmerenUE in many ways. Overall, a market-driven wholesale power sector creates both benefits and challenges for electric utilities.

The current developments in wholesale market restructuring provide at least three distinct benefits. First, RTOs and the "de-pancaking" of transmission rates will help create regional power markets. This will increase the potential set of bulk power supplies that utilities can both sell to and buy from. As a result, utilities will have more generation supply options and more opportunity to expand their wholesale generation sales. Second, generation competition will increase the demand for transmission service. This can increase the revenues that utilities receive from the provision of unbundled transmission service, but it also places many new responsibilities, demands, and risks on transmission providers.

A third benefit of expanded bulk power markets is innovations in trading and risk management. These innovations go hand in hand with the further standardization of commercial terms and "one-stop shopping" provided by RTOs, which will facilitate the further entry and participation of marketers, brokers, and other intermediaries in the wholesale power marketplace. Such intermediaries will, among other things, offer an expanded set of financial hedging and risk management options to wholesale power buyers and sellers. Moreover, increased competition in wholesale power markets should, in and of itself, spur further innovation and place downward pressure on generation prices. Over time, these developments should benefit both utilities and their retail customers.

Wholesale generation markets also create important challenges for electric utilities and their regulators. Under competitive pressures, power traders and other market participants will be aggressive in identifying and pursuing all profitable trade opportunities. As a result, the transmission grid is becoming more heavily used, and maintaining grid-level reliability is becoming more of a challenge than it was under the past industry structure.

It also must be recognized that market-based prices inherently are much more volatile than regulated, cost-based prices. The price spikes that occurred in the Midwest in the summers of 1998 and 1999 illustrate how wholesale prices can increase significantly under extreme weather and demand conditions. Please see Schedule 3. This schedule charts the daily on-peak prices for wholesale power at Cinergy—a commonly quoted hub for wholesale power prices in the Midwest—from January 1997 through December 2001. These prices are reported by *Power Markets Week*. The dark line on Schedule 3 shows the monthly average price for power and the light line shows the daily price. While one expects volatility in the daily price of wholesale power, Schedule 3 shows that there has been significant volatility both in the daily price and in the monthly average price of power. As one can see, the monthly average price exceeded $300/MWh in July 1999 and $250/MWh in June 1998. In 2001, average monthly prices have been fairly stable, with a high of about $50/MWh in January. While the Midwest did not experience particularly volatile wholesale power prices over the last two years, the western U.S. experienced severe and sustained increases in wholesale prices. Indeed, the market "meltdown" that occurred in California and the western U.S. from the summer of 2000 through the first quarter of 2001 shows how sensitive wholesale prices are to a combination of adverse events.[19]

Wholesale price volatility increases the risks faced by electric utilities. For example, the net revenues that an electric utility earns on wholesale power sales can fluctuate significantly from year to year for reasons entirely or largely out of the utility's control. Similarly, the risks associated with power procurement decisions (*e.g.*, buying on the spot market vs. buying in the forward market or under long-term contracts) also increase as wholesale power prices become more uncertain and more volatile. While competition is fostering the development of financial hedges and other risk management tools to help wholesale market participants deal with price volatility, these increased risks are not trivial; nor are the potential financial impacts on a utility's earnings and its retail customers.

Q. How has AmerenUE been affected by increased wholesale competition?

A. AmerenUE is affected by all of the opportunities and challenges of competitive wholesale power markets cited in my previous answer. For example, as a result of FERC Order No. 888 and increased wholesale competition, the demand for transmission service over Ameren's system is much greater today than it was only five years ago, as is explained in the rebuttal testimony of David A. Whiteley. Mr. Whiteley notes that Ameren's transmission system is centrally located in the very active Midwest

[19] Several factors, including deficiencies in market design, contributed to the severe and sustained wholesale price increase in the western U.S. I do not claim that an event of this severity is likely to occur in the Midwest.

bulk power market. In fact, the merger of UE and CIPS created a combined transmission system that offers a highly attractive path to wheel power throughout much of the Midwest. Today, many third parties, including marketers, independent generators, and load-serving entities, use Ameren's transmission system. As a result, the volume of transactions over Ameren's system has increased significantly in recent years.

Another impact on Ameren stems from added volatility in the wholesale power markets. Since Ameren is both a buyer and seller of wholesale power, rapid changes in the availability and price of such power makes buying and selling more difficult and more risky than in the past. While wholesale market revenues and associated profits have contributed to AmerenUE's earnings and shared customer benefits, the volatility of wholesale markets also makes the determination of jurisdictional cost of service much more difficult.

Q. Is there evidence that wholesale market prices will be lower in the next two years than they have been recently?

A. Yes, please see Schedule 4, which shows five forward price curves for firm, on-peak power delivered at Cinergy during the latter half of the test year and update period. These prices are based on the settlement price for power traded at Cinergy via the New York Mercantile Exchange's ("NYMEX") futures contract. The vintage of these forward price curves ranges from late December 2000 to late January 2002.[20] As one can see, the price curve has been declining consistently over this period. The expected summer 2002 peak prices shown in the January 2002 price curve are less than half the summer 2002 peak prices shown in the April 2001 price curve.

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[20] NYMEX stopped trading at Cinergy after January 31, 2002.

C. ELECTRIC INDUSTRY AT A CROSSROADS

Q. Earlier, you said that the electric power industry was at a crossroads between regulation and deregulation. Please explain what you mean by this.

A. What I primarily mean by this is that in wholesale power markets, generation increasingly is sold at market-based rates, whereas in retail markets, much generation continues to be sold at regulated, cost-based rates. This is the case at least in states without retail competition.[21] Thus, many generation owners are selling their output into both competitive wholesale markets, which provide no guarantees in terms of cost recovery, and into regulated retail markets, which have certain presumptions regarding cost recovery, as I explained in Section III. The risks and potential payoffs from selling into these two distinct types of markets are very different.

More generally, there is much uncertainty about where the industry is headed in terms of retail service. There in no broad consensus in favor of retail competition as the desired end state, and the problems in California and the western U.S. have slowed down the trend toward retail access. Nationwide retail access in no longer as inevitable as it seemed just a few years ago. This means that there could be an extended period over which the price of generation is set through competition in some market segments and through regulation in others. This creates significant regulatory uncertainty for the generation and transmission sector.

[21] Most states with retail access provide a transitional "standard offer" or "provider of last resort" service which is pegged to the cost-based price of bundled service in effect immediately prior to the implementation of retail competition. Thus, these states have not entirely abandoned cost-based pricing for generation service.

Q. Is regulatory uncertainty largely restricted to state regulation?

A. No. While there is little question that wholesale markets will continue to become more market based and regional in scope, there is significant uncertainty about the specifics of FERC policy in regard to market-based generation rates, transmission pricing, and RTO scope and design. For example, FERC is in the process of changing the analyses and tests it applies to determine whether a supplier will have permission to sell power at market-based rates.[22] On a related matter, the FERC is grappling with the difficult issue of how to best mitigate market power on a region-wide basis during periods of high demand or other times when supply is limited.

There also is much uncertainty about transmission pricing, such as whether the FERC will permit "merchant" transmission lines that provide service at market-based rates. For cost-based transmission pricing, FERC has encouraged owners to file performance-based or incentive ratemaking proposals, but until such proposals are approved it is not clear how far FERC will be willing to deviate from traditional embedded cost transmission rates. In regard to RTOs, the FERC, among other key issues, continues to evaluate the preferred geographic scope of such organizations, the need for a standard market design, and the desirability of an RTO being a for-profit transmission company ("Transco") as opposed to a non-profit organization that could include one or more Transcos.

[22] See *Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy*, issued November 20, 2001, in which the FERC established a new generation market power screen which will be applied on an interim basis pending a generic review of new analytical methods for analyzing market power.

Q. How does this regulatory uncertainty affect a utility's decision to invest in generation and transmission capacity?

A. The uncertainty associated with regulation of wholesale and retail generation markets and bulk power transmission service is unprecedented in the history of the U.S. electric power industry. This clearly is affecting the risk and uncertainty that vertically-integrated utilities with an obligation to serve face when they consider new investments in generation and transmission capacity.

Let's first consider generation. Even if a utility with an obligation-to-serve builds a new generating plant under cost-of-service regulation and a state-approved resource plan, it cannot be sure how long it will have an exclusive retail franchise or marketing area. Thus, the utility cannot have a high degree of confidence that it will be able to place the generating plant in its rate base and recover its costs, through regulated rates, for the entire economic life of the asset. If all or some of the new plant's output is sold in the wholesale market, the revenues earned by the utility will depend, in part, on the rules and policies that the FERC adopts for market-based generation rates. As I noted above, these rules and policies are being revised. Revenues from the generating plant also will depend on the design and structure of the wholesale power market in the Midwest, including the market rules adopted by the Midwest ISO, which cannot be known at this time.

Transmission investment also is affected by the uncertain status of retail competition because of split federal/state jurisdiction over transmission rates and the transmission revenue requirement. Traditionally, state regulators have been primarily responsible for transmission cost recovery because they establish the transmission component included in rates for bundled retail service. The rate for unbundled transmission service provided to wholesale customers is set by the FERC. However, the FERC has determined that it has rate jurisdiction over all unbundled transmission service, including transmission service provided to retail customers in states with retail competition.[23] When a state implements retail competition, all transmission service becomes unbundled and therefore is subject to FERC's jurisdiction. Hence, primary responsibility for transmission cost recovery switches from state to federal regulators once retail competition is implemented in a state. This fact, and potential differences in state and federal ratemaking practices, contributes to the uncertainty surrounding new transmission investment.

The FERC's increased importance to transmission cost recovery is not solely a function of retail competition and the unbundling of transmission service. As a result of increased activity in the wholesale power market, the FERC will have a greater impact on the revenues generated by a utility's transmission assets than it has had in the past, regardless of whether the utility operates in a state with retail competition. Over the next few years, FERC policies on incentive or performance-based transmission rates, merchant transmission lines, and other aspects of transmission pricing will become more known. Until then, utilities contemplating new transmission investments will need to recognize the significant uncertainty regarding FERC's pricing policies.

RTOs also will affect the value of a utility's transmission assets in numerous ways. For example, the value of transmission assets will be affected by an

[23] The U.S. Supreme Court recently upheld FERC's interpretation of its jurisdiction over transmission service. See 122 S. Ct. 1012 (2002), *New York et al. v. Federal Energy Regulatory Commission*, March 4, 2002.

RTO's tariff and pricing method, its scope and configuration, its efficiency in operating the transmission system, and its method of managing transmission congestion, among other factors. Much of the detail on how RTOs will operate and recover transmission costs is yet to be settled.

Finally, new small-scale or "distributed" electricity technologies are slowly displacing centralized investment in generation and transmission. The pace and degree of displacement is uncertain and will depend on energy prices, federal and state policies, and changes in technology. However, potential penetration of these technologies introduces additional risk into the generation and transmission sectors.

Q. Does all this uncertainty mean that utilities should avoid making investments in generating and transmission capacity until some of these issues are resolved?

A. Absolutely not. Utilities that have an obligation to serve need to invest in the infrastructure necessary to provide adequate, reliable, and cost-effective service. Regulatory and market uncertainty does not allow a utility to waive or modify this obligation. Using the principles of integrated resource planning, utilities should seek to provide adequate and reliable energy services at the least cost.

However, the turmoil and uncertainty facing the electric utility industry today is greater than at any time since the 1930s, and this increases the risk associated with new generation and transmission investments. State regulators need to recognize that the risks and challenges facing electric utilities have changed, and set rates and allowed returns accordingly.

D. NEED FOR ADDITIONAL INFRASTRUCTURE

Q. Has electric transmission infrastructure in the Midwest kept pace with growing demand and market developments?

A. No. The recent FERC Staff Report on the Midwest bulk power market noted that there has been little recent construction of transmission facilities in the Midwest. According to FERC Staff, the reasons for this minimal transmission investment include regulatory siting requirements and the regulatory uncertainty of obtaining a return on the investment because of the evolution of RTOs and the possibility (or reality) of rate freezes in state retail access programs. (FERC Staff Report, p. 2-41)

Constrained transmission capacity is not solely a Midwest problem--there is a need for additional transmission capacity throughout the U.S. Indeed, the FERC has concluded that investments on the order of roughly $12.6 billion are needed to fix major bottlenecks in the nation's transmission system.[24]

Q. Has the lack of new transmission investment and increased market activity affected reliability?

A. Yes. While retail customers are continuing to receive reliable service, the Midwestern transmission grid clearly is becoming more stressed by increasingly active wholesale generation markets and overall load growth. That is shown by the increasing number of transmission loading relief ("TLR") incidents that are being called by Midwestern transmission owners to mitigate transmission constraints. A TLR is a NERC procedure used to mitigate potential or actual violations of the operating limits on

[24] See Utility Committee Final Report, Missouri Security Panel, January 30, 2002.

transmission facilities in the Eastern Interconnection.[25] It is, in effect, a sign that the transmission grid is nearly overloaded and requires transmission operators to take a series of actions to curtail or rearrange power trades to reduce flows to the point where the transmission system is no longer overloaded.[26]

The November 2000 FERC Staff report on the Midwest bulk power market shows that the number of TLRs increased dramatically between the summer of 1999 and the summer of 2000. A total of 492 TLRs were called in the summer of 2000, compared to 86 TLRs in the summer of 1999 (and 107 TLRs in the summer of 1998).[27] Most of this increase was due to TLRs called in the MAIN and ECAR regions. ECAR and MAIN accounted for 85 percent of the TLRs called in the Midwest during the summer of 2000. The FERC staff report further shows that several of the critical transmission facilities where TLRs were most frequently called in the summer of 2000 were on Ameren's system. The rebuttal testimony of Mr. Whiteley includes further information on the TLRs called on Ameren's transmission system.

The MAIN and ECAR regions continued to experience a significant degree of congestion in 2001. In addition, since providing security coordination services on December 15, 2001, the Midwest ISO (which serves part of MAIN and ECAR) has called far more TLRs than any other security coordinator. The large amount of TLRs in MAIN, ECAR, and the Midwest ISO strongly suggests that additional transmission and generating capacity is needed in these two reliability councils. Moreover, as the Midwest ISO proceeds to establish a broad, regional power market, demand for bulk power

[25] *Investigation of Bulk Power Markets – Midwest Region.* FERC Staff Report, November 1, 2000.

[26] Improved transmission pricing can help alleviate these overloads, in addition to expanded physical capacity.

[27] All the TLR data cited in this section refer to TLRs of level 2 or higher.

transmission service in the MAIN region (and the Midwest in general) is very likely to increase.

Fortunately, the large number of TLRs have not caused any region-wide service disruptions or price spikes for retail customers. However, as the FERC staff points out, TLRs have a negative effect on the wholesale market. TLRs inhibit optimal functioning of the transmission system, and thereby the market, because buyers and sellers lack confidence that their trades will not be interrupted.

Q. Do federal policies obligate AmerenUE to make added transmission investment?

A. Only indirectly. Fully established federal policies (*i.e.*, FERC Order No. 888) require AmerenUE to provide reliable, non-discriminatory transmission service to all buyers and sellers of wholesale power. This obligation is much like AmerenUE's obligation under Missouri law to serve all customers in its territory. However, the federal government cannot order a utility to build a transmission line. Instead, the FERC relies on AmerenUE and the MPSC, and, in the future, AmerenUE's RTO, to plan and construct adequate transmission capacity in AmerenUE's service area.

Q. Is Ameren making investments in transmission to meet this responsibility and ease the increasing strain on its system?

A. Yes. As explained in the rebuttal testimony of Mr. Whiteley, AmerenUE has made $76 million of capital improvements to its transmission system over the last five years and is planning to construct approximately $400 million of transmission system upgrades during the next five years. A subset of these upgrades, if built, will enable AmerenUE's to increase its import capability by 1300 MW by 2005.

Q. Is Ameren also building or planning to build additional generating capacity?

A. Yes. In addition to significant purchases of generating capacity, AmerenUE is planning to increase its installed generating capacity significantly over the next five years. AmerenUE's planned generation additions and upgrades are described in the rebuttal testimony of Garry L. Randolph and Craig D. Nelson. The Company's planned generating infrastructure investment for this same period exceeds $1.6 billion.

Q. Does AmerenUE also need to expand its distribution infrastructure?

A. Yes. AmerenUE's planned investment in distribution infrastructure over the next five years exceeds $600 million.

E. STAFF FAILURE TO CONSIDER IMPORTANT INDUSTRY DEVELOPMENTS

Q. Have you reviewed the testimony filed by all Staff witnesses in this docket?

A. Yes, I have.

Q. Based on your review of Staff's testimony in this docket, is there any indication that Staff took electric industry developments into consideration in their proposed rate filing?

A. No. I see no evidence that Staff took industry developments into account in their proposed rate filing. The only Staff witnesses who have even a cursory discussion of policy issues in their testimony are Ronald L. Bible and Michael S. Proctor. As I noted in Section II, Mr. Bible says that it is important to consider the historical and projected economic conditions and the business operations of a utility in order to calculate a fair and reasonable return. However, Mr. Bible's review of historical economic conditions is largely limited to recent trends in interest rates and inflation rates, neither of which are specific to the utility industry or its changes. Mr. Proctor's policy review is largely limited to affiliate transactions and his recommendations are counter-productive because he proposes a rule that would, among other things, discourage economical power trades between AmerenUE and its affiliates. There is no sign that others on Staff have considered the critical changes in the industry that I have described in this testimony.

Q. Why should Staff's filing take account of industry trends and changes in a dispute over AmerenUE's cost of service?

A. I recognize that Staff and AmerenUE have strongly divergent opinions about the Company's current cost of service. However, in setting rates for AmerenUE, the MPSC needs to consider the context in which the Company operates and its significant need for additional infrastructure. I noted above how the competitive wholesale power market has affected utilities and their customers. Enhanced wholesale competition has enabled AmerenUE to earn increased revenue through the sale of wholesale power and unbundled transmission service. At the same time, the increased use of Ameren's transmission facilities, coupled with load growth, is forcing the Company to make significant investments in its grid. Hence, the evolving wholesale power market is increasing AmerenUE's revenues, opportunities, and costs independent of actions taken by the MPSC. Moreover, the risks inherent in today's utility industry are much larger than at anytime since the industry became regulated.

State regulation needs to recognize that the risks, challenges, and opportunities facing electric utilities have changed. These changes need to be considered in the determination of Ameren's rates.

Q. Generally speaking, how should these industry changes be factored into a modern ratemaking proceeding?

A. There are several ways in which industry changes should be reflected in a rate case. For example, actual or historical costs should be viewed with the realization that some costs have changed rapidly and unpredictably in the recent past. It is poor regulatory policy to "punish" a utility for incurring costs that were reasonable based on information available at the time but which appear to be higher than absolutely necessary with the benefit of hindsight. Nor would it be appropriate to set rates that "lock in" non-jurisdictional revenues as an offset to jurisdictional costs, if such revenues are based on success in the utility's wholesale operations, but the continued realization of such benefits is unlikely.

Rather, it must be recognized that future costs and forecasts of all types are more uncertain than before. In some cases, this calls for a greater range of allowed costs (*i.e.*, a "buffer"). And it certainly calls for using the most recent actual and best available forecasted data for setting rates.

A corollary of these forward-looking uncertainties is that properly-structured incentive regulation confers some advantages over the traditional regulatory model. By not strictly linking authorized revenues to realized operating costs, incentive regulation can provide companies with strong incentives to control costs and increase other aspects of performance. For example, well-designed incentive regulation would provide AmerenUE with strong incentives to manage the risk of volatile cost elements, such as fuel and purchase power costs. By contrast, cost-of-service regulation could entail a transaction-by-transaction review of each wholesale power purchase or sale made by AmerenUE as well as each financial hedge purchased by the company. Such regulatory micro-management would entail significant administrative cost and also could make Ameren management tentative and risk averse. No wholesale market participant or load-serving entity will make a "good" deal in every case. Moreover, given the inherent uncertainty and volatility of competitive wholesale power markets, it is very difficult to determine at any given point in time whether a company's supply strategy has been prudent and cost-effective. Long-term contracts that are economic at one point can suddenly become uneconomic a short time later if spot prices fall unexpectedly.

A better approach, in my view, is to give AmerenUE improved financial incentives to manage its power supply portfolio and operate its generating assets in an economical manner. If this incentive included an earnings sharing plan, both Ameren's shareholders and customers immediately benefit if the company's realized rate of return increases, in part, because of superior management of its power supply portfolio. Similarly, Ameren's shareholders will experience lower earnings if the company does a poor job of managing its generating assets and its wholesale power transactions.

To summarize, when future costs and risks are relatively predictable, cost-of-service regulation and infrequent traditional rate cases have worked well. When costs are volatile and unpredictable, incentive regulation makes more sense.

Another way in which industry changes affect a rate proceeding is through the allowed rate of return. Witness Kathleen McShane addresses this subject in her rebuttal testimony.

Q. Have you found any evidence that Staff has factored these changes into its case?

A. No, I have not. Apart from portions of Mr. Bible's and Dr. Proctor's testimonies, Staff's case looks largely like an accounting exercise, based on historical costs, without any attempt to consider the additional important goals of regulation.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission, Complainant,	)	
vs.	)	Case No. EC-2002-1
Union Electric Company, d/b/a AmerenUE, Respondent.	)	

AFFIDAVIT OF PETER FOX-PENNER

DISTRICT OF COLUMBIA) ss

Peter Fox-Penner, being first duly sworn on his oath, states:

1. My name is Peter Fox-Penner. My business address is 1133 20th St. NW, Washington, D.C. and I am a principal and chairman of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, Washington, and London.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 51 pages, Appendex A and Schedules 1 through 4, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Peter Fox-Penner

District of Columbia SS.
Washington, DC

Subscribed and sworn to before me this 30th day of ~~May~~ April, 2002.

Notary Public

My commission expires:

Deborah Bailey
Notary Public District of Columbia
My Commission Expires: March 14, 2003

EXECUTIVE SUMMARY

Peter Fox-Penner, Ph.D.

Chairman of The Brattle Group, an economic and management consulting firm with offices in Cambridge, Washington, and London, who is an economist and author with over two decades of experience in government and consulting, primarily in the area of regulated utilities, including service during the Clinton Administration as a Senior Advisor in the White House Office of Science and Technology Policy and as a Special Assistant to the Deputy Secretary of Energy

* * * * * * * * * *

My testimony addresses the basic principles and objectives of sound regulation, responds to Staff position which are inconsistent with good energy policy, and discusses important industry "facts and circumstances" that the Commission should consider in this proceeding. My discussion occurs in two parts. First, I review the objectives of public utility regulation from an economic perspective and discuss the importance of a paradigm that provides utilities a fair opportunity to recover their costs and incentives to operate efficiently. Second, I describe how the industry and federal and state regulation have evolved over the last decade and summarize the current turmoil and uncertainty now facing the industry.

My principal conclusions are as follows:

1) A significant deficiency in the case prepared by the Staff of the Missouri Public Service Commission ("Staff") is its failure to consider economic and regulatory conditions in the electric industry generally and in the Midwest. There is no evidence that Staff took important industry developments into account in their proposed rate filing. Indeed, Staff's case largely looks like an

accounting exercise. In setting rates and returns for AmerenUE, I believe that the context in which the Company operates and its significant need for additional infrastructure are "relevant facts" that the Commission needs to consider.

2) The electric power industry has changed significantly over the last fifteen years, and this change has accelerated over the last five years. The most significant change during this entire period is the increasingly competitive nature of the generation business. The introduction of wholesale power competition, combined with the continued regulation of transmission service and continued state regulation of generation service in at least half of the United States has created an extraordinarily complex and uncertain industry structure. Today, the electric power industry is at a crossroads between regulation and deregulation. This is the case because, in wholesale power markets, generation is widely sold on a competitive basis, whereas in many retail markets generation continues to be sold at regulated, cost-based rates.

3) Industry change and the uncertainty associated with the regulation of wholesale and retail generation markets and bulk power transmission service clearly is affecting the risk and uncertainty that vertically-integrated utilities with an obligation to serve face when they consider new investments in generation and transmission capacity. For example, even if a utility with an obligation-to-serve builds a new generating plant under traditional regulation and a state-approved resource plan, it cannot be sure how long it will have an exclusive retail franchise or marketing area. Thus, the utility cannot have a

high degree of confidence that it will be able to recover its costs, through regulated rates, for the entire economic life of the plant. With regard to transmission investment, there is much uncertainty as to whether federal or state regulators will have primary responsibility for enabling transmission cost recovery. Moreover, the likely expansion of federal jurisdiction creates uncertainty about the rate methods and formulas that will be used to recover transmission costs. State regulation needs to recognize that the risks and challenges facing electric utilities have changed and set rates and allowed returns accordingly.

4) I note that retail sales growth and increased use of its bulk power transmission system is forcing AmerenUE to make significant investments in electric infrastructure over the next 5 years. According to AmerenUE witness David Whiteley, AmerenUE plans to invest approximately $400 million over the next five years in Missouri to expand its transmission capacity and improve its import capability. AmerenUE also plans to make investments of over $2.2 billion in generation and distribution capacity over this same period.

5) A "just and reasonable" rate is one that properly strikes the key balance between the provision of reliable service at reasonable cost and adequate returns to utility investors. Regarding the latter, just and reasonable rates give a utility a fair opportunity to recover its prudently-incurred costs and to earn a return on capital that is commensurate with the return earned by other companies with comparable risks.

6) Dr. Proctor's recommendation that AmerenUE should buy power from a non-regulated affiliate at the lower of cost or market prices will make it very difficult for an affiliated generating company to earn market returns, consistent with those earned by competitive generators, on sales to AmerenUE. This will discourage economical power trades within the Ameren system.
7) Another deficiency in Staff's case is its apparent approach towards management efficiency and rate of return, an approach that is inherently unsuited to yielding a fair rate of return and ensuring adequate investment. Regardless of how hard management tries, as long as they pass the threshold test of not being declared "poor or inept," under the Staff's approach, AmerenUE will earn the same ultimate return on equity or less. This is a discouraging climate for new investment, especially if industry-wide changes and risks are unusually high. Thus, Staff's approach to setting the return on equity conflicts with the objective of encouraging good management performance and thus reduces AmerenUE management's incentive to perform well.
8) Historically, cost-of-service ratemaking has been the preferred method for setting electric utility rates. Cost-of-service ratemaking has been widely used, in part, because it is particularly well suited to an industry with steady, predictable sales growth and constant or slightly declining costs. Today, however, some electric utility costs, such as purchase power costs, are more volatile than they were in the past. The changed industry environment has

created numerous—and increasingly complex—opportunities for utilities to control costs and improve other aspects of their performance. For these and other reasons, the drawbacks of cost-of-service regulation are more significant today than they were in the past. Hence, there is increased interest among regulators in establishing alternative ratemaking methods that give utilities a stronger incentive to improve performance.

9) The primary alternative to cost-of-service regulation is a set of ratemaking methods commonly known as incentive regulation. Incentive regulation differs from cost-of-service regulation in that it partially decouples a regulated firm's rates from its costs and uses explicit financial incentives to motivate the firm's behavior.

PETER S. FOX-PENNER **Principal and Chairman of the Board**

Peter Fox-Penner is an economist with an engineering background and more than twenty years of experience in regulated industries, energy policy, and environmental issues. In a career that has spanned consulting, senior government service, and academia, he has assisted numerous public and private clients in settings that include expert testimony, publications and speeches, and advice to senior management and boards. He is the author of numerous publications and books and a frequent speaker at conferences and meetings.

Dr. Fox-Penner has a long involvement in utility deregulation economics and policy. He is the author of the acclaimed *Electric Utility Restructuring: A Guide to The Competitive Era*, a best-selling work on the subject, and participated in extensive energy and network industry policy activities within the U.S. government. A former vice president at Charles River Associates, Dr. Fox-Penner joined the U.S. Department of Energy in 1993 as the Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy, where he held COO responsibilities for a unit of the Department with a budget of approximately $1 billion. He later served as a senior advisor in the White House Office of Science and Technology Policy and an assistant to the Deputy Secretary of Energy. In 1996, he joined *The Brattle Group* as a Principal and Director of the Washington, DC office.

Dr. Fox-Penner received his B.S. in Electrical Engineering and his M.S. in Mechanical Engineering (Energy Policy) from the University of Illinois, and his Ph.D. in Economics from the Graduate School of Business, University of Chicago.

REPRESENTATIVE EXPERIENCE

Regulated Industries and Electric Restructuring

- Electric utility restructuring
- Performance-based and price cap regulation
- Antitrust, market power, and merger-related issues in regulated industries
- Network and transmission pricing, access rules, and governance
- Utility convergence and retail utility strategic issues
- Economic and policy issues in public interest utility programs
- Load and sales forecasting, pricing, and new product analysis
- Utility telecommunications regulatory issues and strategy

Peter S. Fox-Penner
Principal and Chairman of the Board

Energy, Environmental, and Technology Policy

- Energy taxes
- Pollution permits and trading schemes
- Technology and Market Evaluations
- Public Policies Towards New Technologies and R& D
- Energy conservation—economics and policy
- Energy externalities
- Nuclear power: economics, litigation, and regulation
- Energy security policies and the strategic petroleum reserve

EMPLOYMENT HISTORY

2001-Present: Chairman, *The Brattle Group*, Washington, DC

1996-Present: Principal and Director, *The Brattle Group*, Washington, DC

1993-1996: Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy, United States Department of Energy

Senior Advisor for Technology Policy, Office of Science and Technology Policy, Executive Office of the President

Assistant to the Deputy Secretary of Energy

1989-1993: Vice President, Charles River Associates, Boston, MA

1991-1993: Professorial Lecturer, Center for Energy and Environmental Studies, Boston University

1987-1989: Senior Associate, Charles River Associates

1980-1983: Research Engineer and Chief Research Engineer, Illinois Governor's Office of Consumer Service, Chicago, IL

1977-1980: Research Assistant and Research Engineer, Office of Vice Chancellor for Energy Research, University of Illinois, Urbana, IL

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"What Does the California Experience Tell Us About Fixing the Rest of America's Power Markets?" By Peter Fox-Penner and Joseph B. Wharton. Presented at the National Association Business Economics Regional/Utility Roundtable, April 24, 2001.

"Taming the Lions in America's Electric Markets: Five Major Challenge." Presented at National Governors' Association Center for Best Practices, Executive Policy Forum on Energy, "*Is Electricity Restructuring in Jeopardy?*" Washington, DC, April 5, 2001.

"The Challenge to Co-operatives in the Electric Power Industry of the 21st Century." NRECA's 30th Annual CEO Leadership Conference. Keystone, CO, August 2, 2000.

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"Incentives, Regulation and Transmission Companies: One Practioner's View." Presented to The Federal Energy Regulatory Commission's RTO Staff. Washington, DC, July 16, 1999.

"ISOs, Transcos, Gridcos, and Long-Run Power Industry Efficiency." Federal Energy Bar Association's Mid-Year Meeting. Washington, DC, December 4, 1998.

"Market Power Issues in Restructured Electric Power Markets." American Bar Association's Satellite Seminar, "Critical Federal and State Practice Issues in Electricity Deregulation." Washington, DC, December 3, 1998

"SAVIOR OR BUREAUCRAT? ISOs, Competition, and Independent Transmission Companies." Winning with Retail Competition, 2nd Annual PUR Conference, Arlington, VA, June 22, 1998.

"The Evolution of the Energy Services Industry." *Have it Your Way: Buying and Saving Energy in the Age of Customer Choice*, Annual Meeting of Energy Management Consortium and the Northeast Energy Efficiency Council, Boston, MA, September 18, 1997.

"Volatility and Stability in the Deregulated Generation Marketplace." Restructuring and Convergence, Successful Strategies in the Energy Services Marketplace, Arlington, VA, May 22, 1997.

"Progress and Promise: The Clinton Administration's Efforts in Fostering Sustainable Development." Global Accords for Sustainable Development: Enabling Technologies and Links to Finance and Legal Institutions Conference, M.I.T., Cambridge, MA, September 5, 1996.

Invited Speaker, Fourth Biennial Conference of the International Society for Ecological Economics, Boston, MA, August 7, 1996.

"Linking Energy, Environment, and Technology to the Economy." Globalcon Energy and Environment Exposition, April 3, 1996.

21st Annual Illinois Energy Conference, November 1996.

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"Technology and Economic Growth: The Government's Role." M.I.T. Club of Washington, DC, October 10, 1995.

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"The Federal Role in Energy Efficiency." Eighth Biannual DSM Evaluation Conference, Chicago, IL, August 24, 1995.

Invited Speaker, Seventh National DOE/EPRI Demand-Side Management Conference, Dallas, TX, June 28, 1995.

"Utility Restructuring and Regulatory Reform." Invited Presentation, National Association of Regulatory Utility Commissioners Attorneys' Conference, Tucson, AZ, May 18, 1995.

Invited Speaker, Conservation Committee, Semi-Annual Meetings of the National Association of Regulatory Utility Commissioners, 1994 and 1995.

Invited Panelist, OECD Seminar on Sustainable Production and Consumption, Massachusetts Institute of Technology, December 19, 1994.

"Electric Utilities and the Environment: Restructuring Need Not Mean Retreat." Invited Presentation, "Brave New World - Managing Externalities in a Competitive Electric Utility Industry." University of Illinois Center for Regulatory Studies, Chicago, IL, November 17, 1994.

Invited Speaker, International Ground Source Heat Pump Association, Hershey, PA, October 17, 1994.

Invited Speaker, "Washington: Business and Public Policy," Brookings Institution Seminar, October 18, 1994.

"Federal Climate Change Management Programs and Climate-Wise," Businesses for Social Responsibility 1994 Environment Conference, Boston, MA, October 13, 1994.

Invited Speaker, National Association of State Energy Officials, Asheville, NC, August 31, 1984.

Invited Speaker, Annual Meeting of the California Institute for Energy Efficiency, Berkeley, CA, July 25, 1994.

"Voluntary Greenhouse Gas Reporting Under the Energy Policy Act of 1992." Invited Presentation, International Conference on Global Climate Change, Center for Environmental Information, Washington, DC, February 1993.

Panel Moderator, Natural Gas Procurement Strategies, Association of Energy Engineers Annual Conference, Boston, MA, June1992.

Panel Moderator, Alternative Fuel Vehicles Conference, the Management Exchange, Washington, DC, April 1992.

Invited Presenter, American Water Works Association. Conservation Committee Workshop, Austin, TX, January 1992.

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"An Introduction to Competitive Power Procurement." University of Illinois Center for Regulatory Studies, Workshop on Competitive Bidding, Chicago, IL, October 10 and May 9, 1990.

Invited Presenter, "Is Deintegrated Electricity Efficient?" *Resources for the Future*, Washington, DC, February 14, 1990.

Chair, "Cogeneration IPPs — Current Developments," Association of Energy Engineers, 12th World Energy Engineering Congress, October 25, 1989.

Convener, Electric Power Research Institute (EPRI) Workshops on Competitive Resource

Procurement ("Bidmet"), Chicago, IL, October 18, 1989.

"IPP Bidding: The View From Today's Utilities." *Proceedings* of the Third Annual Conference, American Cogeneration Association, September 25-27, 1989.

"Purchasing Independent Generation: The Case for Negotiated Contracts." With Mary Smith. *Utility Opportunities in New Generation* (EPRI CU-6605). Palo Alto, CA: Electric Power Research Institute, June 1989.

Invited speaker, Least–Cost Utility Regulation, National Association of State Utility Consumer Advocates, Columbus, OH, June 15, 1989.

Seminar on electric power transmission, RETSIE Conference, Santa Clara, CA, June 19, 1989.

"Purchasing Independent Generation: The Case for Negotiated Contracts." Presentation with Mary Smith, EEI/EPRI Utility Opportunities for New Generation, Boston, MA, June 29, 1989.

Invited Speaker, "The Outlook for IPPs in Washington," the Independent Power Producers of New York (IPPNY) 3rd Annual Meeting, Albany, NY, December 2, 1988.

"Resource Recovery: Evaluating the Development Benefits." Part of the session: Waste–to–Energy Sales and Economic Development, the National League of Cities Resource Recovery in Transition Conference, Arlington, VA, November 15, 1988.

Co-chair, session on the Canadian Electric Power Trade, the American Cogeneration Association and Cogeneration & Independent Power Coalition of America (ACA/CIPCA) 2nd Annual Meeting and Exposition, Chicago, IL, September 26, 1988.

"An Econometric Analysis of the Impacts of PURPA Enforcement Differentials." *Proceedings of the Sixth NARUC Biennial Regulatory Information Conference.* National Regulatory Research Institute, September 1988.

ADVISORY BOARDS AND OTHER PROFESSIONAL ACTIVITIES

Advisory Board, Center for National Policy, Washington, DC, 1993-1996

Advisory Board, Massachusetts Institute of Technology Energy Laboratory, 1993-1996

Nominator, Heniz Foundation Awards, 1995-1996.

Hearing Official, National Energy Policy Plan Hearings, United States Department of Energy, 1994.

Member, Interagency Climate Change Management Committee, Council on Environmental Quality, 1992-1995.

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Energy Efficiency and Renewable Energy Group Leader, U.S.-Mexico Energy Trade Mission, June 1995.

Advisor to the Federal Fleet Conversion Task Force, U.S. Department of Energy, 1994.

Attendee, U.S.–Japan Energy Policy Consultations, Atlantic Council of the United States, U.S. State Department, November 6–8, 1990.

Member, Illinois Solar Energy Advisory Board, 1980.

HONORS AND AWARDS

Who's Who in the East (1991, 1992)
Fellow, Center for the Study of Economy and the State, University of Chicago, 1986
NSF Travel Fellow, Dec. 1981
MIT Institute Fellowship, 1978
Earle C. Anthony Fellowship, 1978
Union Carbide Fellow, 1977-78
Michigan Annual Giving Scholarship, 1976
Illinois State Scholar, 1976
National Merit Scholar, 1976
Sigma Tau Beta
Phi Kappa Phi
Eta Kappa Nu

TEACHING AND RESEARCH SUPERVISION

Professorial Lecturer, Center for Energy and Environmental Studies, Boston University, 1991 and 1992. Designed and taught original course in graduate environmental economics and policy.

Supervisor of 5 student master's theses and member of one Ph.D. committee, Boston University Center for Energy and Environmental Studies, Boston, MA.

Teaching Assistant, Pricing Practices, Professor B. Peter Pashigan, University of Chicago, 1986.

Guest Lecturer at Massachusetts Institute of Technology and University of California, Berkeley.

REVIEW WORK

Energy, Science, Resources and Energy, U.S. Department of Energy.

Shock Waves: Enron 's Swoon Leaves A Grand Experiment In a State of Disarray — Electricity Policy May Be Left To Lurch Between Poles Of Regulation, Free Rein — Recession Is Powerful Factor

By Rebecca Smith
Staff Reporter of The Wall Street Journal

11/30/2001
The Wall Street Journal
A1

It was one of the great fantasies of American business: a deregulated market that would send cheaper and more reliable supplies of electricity coursing into homes and offices across the nation.

But look what's happened instead. Enron Corp., the vast energy trader at the center of the new freewheeling U.S. power markets, now faces collapse amid a blizzard of questionable financial deals. And California, the first big state to deregulate its electricity market, has watched its experiment turn into a disaster, with intermittent blackouts and retail power rates as much as 40% higher than they were a year ago.

Now, with the power industry hovering uneasily between regulation and deregulation, it faces the prospect of a market that combines the worst features of both: a return to government restrictions, mixed with volatility and price spikes as companies struggle to meet the nation's future energy needs.

Investors and lenders, spooked by the twin specters of California and Enron , have become less likely to commit capital to building new power plants, transmission lines and natural-gas pipelines. The U.S. will require big additions to its power production and distribution capacity when it emerges from the current recession -- but for now, at least, the nation's capital markets are reluctant to cough up the necessary funds.

Responding to the dramatic decline in their stock prices and the recession, energy companies are retrenching. Calpine Corp., one of the most aggressive players in the deregulated market, is waffling on previously announced plans to build billions of dollars in new power plants. Virginia-based AES Corp., which has missed its recent earnings targets, has scaled back its expansion goals and is selling some of its foreign assets. Northeast Utilities is curtailing plans to build a 30-mile undersea transmission line from Connecticut to Long Island.

Meanwhile, regulators are racing to place new guardrails on the U.S. power market. The federal government is trying to beef up its market-surveillance activities. And it also is trying to broker deals between states that might make interstate energy transmission faster, cheaper and easier.

The power market is in "the midst of an ugly adolescence that we cannot allow to last much longer," says Nora Brownell, a member of the Federal Energy Regulatory Commission in Washington.

That's because, for the consumer, energy deregulation has been anything but good news. Unlike the deregulated telecommunications market, where fierce competition brought down prices while guaranteeing a reasonable level of reliability, the deregulated power market isn't likely to provide real benefits until it stabilizes. For now, consumers are at the mercy of wholesale forces they often can't understand and have few real options to switch between service providers.

The theory behind deregulation was that it would lead to the emergence of efficient companies that would specialize in providing electric power, carrying it over long distances or delivering it to a final customer.

While the industry started to move in that direction, it isn't anymore. Many big power companies in the most populous states, which are the ones that also happen to be deregulated, still do a little of everything and are increasingly confused about where to place their business bets.

When it comes to electricity markets, says Frank Wolak, a Stanford University economics professor, these kinds of "hybrids don't work." But, he fears that they will be around for some time to come, especially since regulators, who once thought the markets themselves would bring about deregulation's goals, are only belatedly assuming responsibility for making sure things run smoothly.

Enron 's sudden meltdown will deal a heavy blow to the broader energy marketplace that sat at the center of electricity deregulation -- providing a place for utilities and power plants to buy energy they needed in a hurry, or to unload their excess supplies. The company's EnronOnline trading system, which was shut down Wednesday, accounted for a quarter of all wholesale energy trades among U.S. utilities, independent power producers and other market players.

The trading system's shutdown came in the wake of disclosures that Enron 's directors and top officers approved a series of partnerships that moved debts off the company's balance sheet. In several cases, those partnerships enriched company officers but later produced huge losses for Enron .

That kind of "balance-sheet abuse" says Goldman Sachs analyst Jonathan Raleigh, might now "reduce overall liquidity and cause lenders to tighten credit standards" for the entire energy-trading industry. The result could be the kind of supply squeezes that led to six days of blackouts in California earlier this year.

California's supply problems didn't spread beyond the Pacific Northwest -- but that's largely because of the sharp economic downturn. As spot-market power prices in California shot up to an average of $317 per megawatt in December 2000 from $32 per megawatt hour the preceding April, energy companies were making enormous amounts of money. Investors drove up the price of the companies' stocks, with Enron at one point trading at 60 times its projected next year's earnings. New funding was flooding in from debt and equity markets. Under pressure from regulators worried about a repeat of the California debacle, energy companies got busy building power plants, drawing up plans to fix the nation's antiquated electric-transmission systems and plotting new natural-gas pipelines.

But that golden moment for the industry turned out to be short-lived. Early this year, federal energy regulators placed caps on the wholesale price of power sold in the western U.S. as California's two main investor-owned utilities were pushed to the brink of insolvency. Then, in the spring, natural-gas and electricity prices collapsed around the country as the economy suddenly slowed to a crawl. Even before Enron got into trouble, the big energy companies began to see their stock prices sink, and investors began to cast a more critical eye on their expansion plans in the wake of the California chaos and the resulting multibillion-dollar electricity payment crisis.

One of the first signs that a sea change was under way came a few months ago when demand for power-generation turbines began to soften. Because there are only three domestic suppliers of such multimillion-dollar engines, the most expensive pieces of machinery used by commercial electricity producers, the machines must be ordered well in advance of their deployment.

A year ago, says David Sokol, chief executive of Iowa-based utility owner Mid-American Energy Holdings Co., "you had to pay a premium to get a turbine." Companies with lots of turbines on order, such as San Jose, Calif.-based Calpine, boasted that they would clean up in newly deregulated markets such as the West, the Northeast and New York, where electricity supplies back then were tight. "But now," Mr. Sokol says, "I know of at least 100 [turbines] that are for sale. People want you to take their place in line."

While most energy companies are pressing ahead with projects they have started, they have grown cautious about breaking ground on new ones. Just a few months ago Calpine boldly claimed it would have 70,000 megawatts of generating capacity -- the equivalent of 35 to 45 big power plants -- in operation by 2005. Now it's backing away from that assertion. The company currently has only a fraction of that capacity, 11,000 megawatts.

At the root of the problem is a lack of capital and earnings. While energy companies routinely beat their own bullish quarterly profit estimates last year, many of them have lately indicated that they will miss earnings projections.

With electricity and natural-gas prices down, energy sales tend to be less profitable. Hence, investors haven't been willing to pay the same price-earnings multiples for energy stocks.

Bankers, meanwhile, want convincing evidence that future power prices will be high enough to justify new projects. That's far from guaranteed in deregulated markets. In fact, national electricity prices, which hit a 52-week peak of $216 per megawatt, now are being quoted at $23.45 per megawatt, according to the Mirant National Power Index.

To give some idea of how radically the landscape has shifted, take the case of power conglomerate UtiliCorp United Inc., of Kansas City, Mo. In April, taking advantage of the general enthusiasm toward deregulated markets, it spun off its Aquila Inc. trading unit at a price of $24 a share, raising $480 million. "We saw an opportunity to crystalize the value" of the trading company, says UtiliCorp President Bob Green.

Aquila's stock soared to $35 before it began slipping at the end of May. Since then, it has tumbled by half. Today, with a price/earnings ratio of eight -- less than most utilities -- the "equity markets are closed" to Aquila, Mr. Green says.

Now, UtiliCorp, which mainly owns regulated utilities, is planning to buy back all the publicly traded Aquila shares. It hopes that by taking shelter under UtiliCorp's umbrella, Aquila will be able to benefit enough from its parent's strong credit rating and healthy balance sheet to keep trading and buying more power plants.

In other words, the regulated utilities, once considered homely wallflowers, are looking more alluring these days as trading firms, such as Aquila and Enron , have fallen from favor. That could portend a reduction in the huge trading volumes, and accompanying price volatility, that marked the early stages of energy deregulation.

But that won't help consumers unless new power plants and transmission lines come online in time for the economy's resurgence and new rules are put in place that guarantee a more transparent market. The latter won't be an easy task, because power trading is done on a variety of public and private exchanges, with traders darting in and out to take advantage of price discrepancies.

Lately, there's been growing evidence that some power companies have found lucrative ways to exploit this system -- at consumers' expense. Their tactics include manipulating wholesale electricity auctions, taking juice from transmission systems when they aren't supposed to and denying weaker competitors access to transmission lines. Regulators believe that this behavior has contributed to supply glitches and inflated prices.

Under its new chairman, Pat Wood, the FERC has been pressing companies to take steps it believes will create power markets that are less susceptible to such shenanigans. Chief among them is for utilities to surrender control of their high-voltage power lines to independent operators that would give all market participants fair access and will operate spot markets for power.

Earlier this month, the commission told three of the nation's big integrated utilities -- American Electric Power Co., Entergy Corp. and Southern Co. -- that until they relinquish control of their power lines to an independent operator, FERC may intervene to limit the prices they charge wholesale customers. At least one of the three is appealing the FERC mandate.

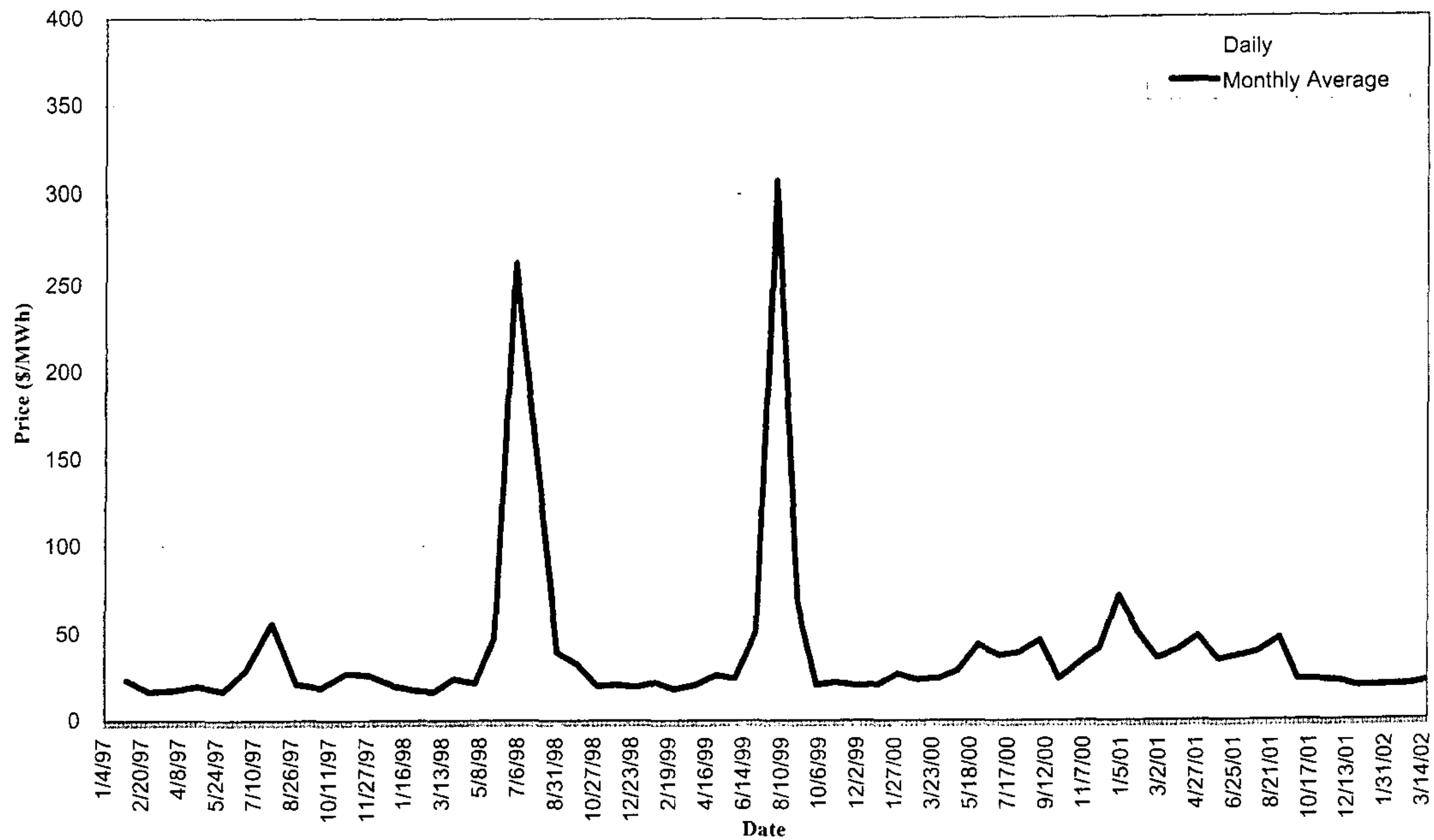
The commission has also stepped up efforts to settle pesky but important technical issues, such as how independent power producers can hook up new plants to the lines of nearby utilities and how transmission services can best be priced.

Still, even a more aggressive FERC hasn't been able to solve some lingering problems. A good example is the continued existence of one of the nation's worst transmission bottlenecks. Known as "Path 15," the line interconnects the populous southern part of California with more abundant energy resources in the north. The Department of Energy has pledged to help expand Path 15, which was implicated as a key cause of the blackouts in California earlier this year.

But actually getting the work done may require PG&E Corp.'s Pacific Gas & Electric unit, which owns the 90-mile stretch of line, to get approval for the expansion from the state Public Utilities Commission. But Pacific Gas, which placed itself under the protection of the federal bankruptcy courts amid the California power crisis, is at loggerheads with the PUC. The upshot is that there may be significant delays in upgrading Path 15. The implication: when the economy cranks back up, so too will the possibility of more supply shortages and higher prices, says Terry Winter, chief executive of California's Independent System Operator, which operates the state's electricity grid.

(See related letter: "Letters to the Editor -- Advice for California: Join the Free Market" -- WSJ Dec. 10, 2001)

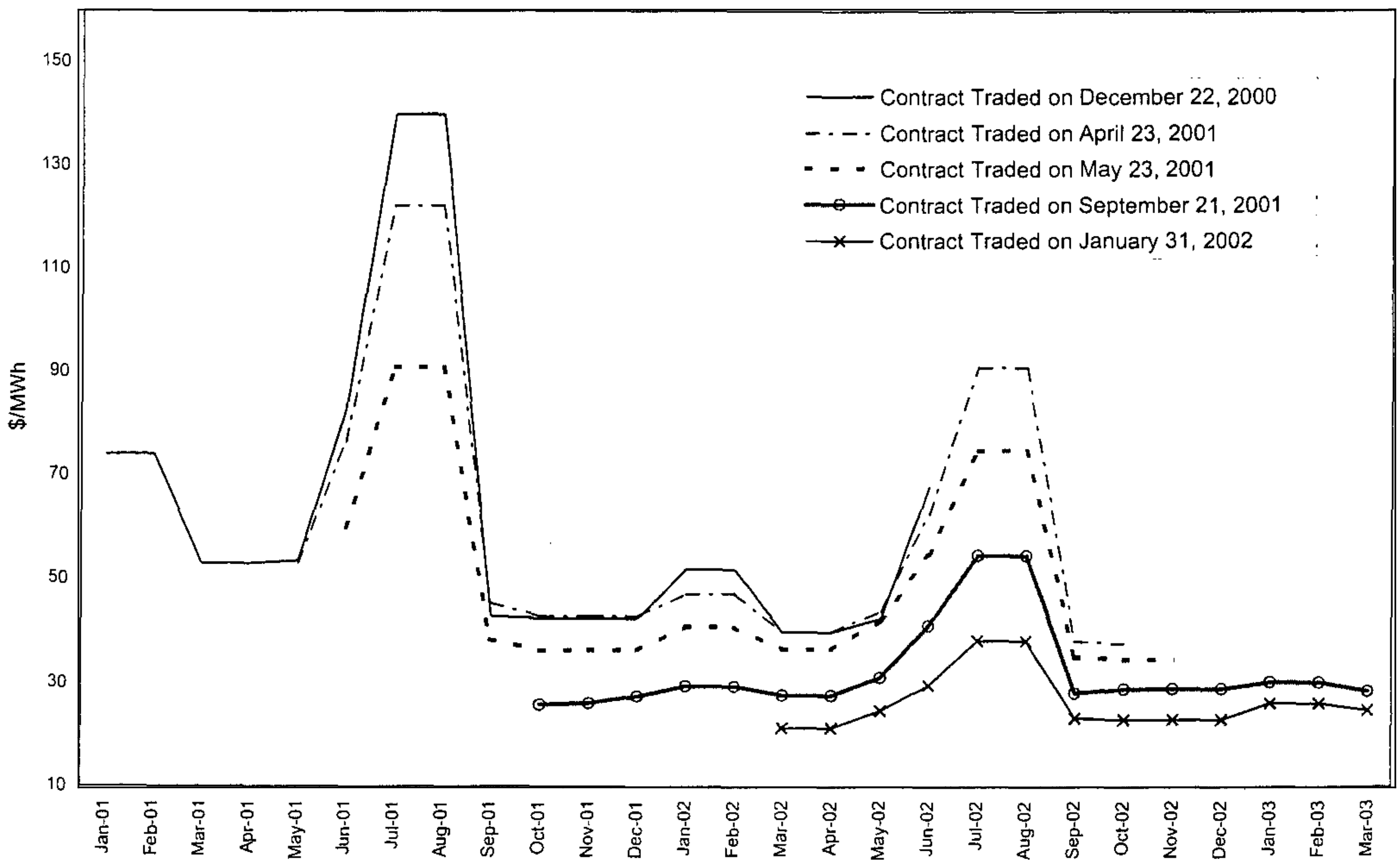
Cinergy Daily and Monthly Average Prices During Peak Hours
Using Daily Prices from Power Markets Week



Source: Platts Power Markets Week Price Index Database

Schedule 3

Forward Prices for 1 Month, 5x16 Hours Power Contracts at Cinergy



Source: Bridge and NYMEX

Schedule 4