Exhibit No.:	
Issue(s):	Market Power
Witness/Type of Exhibit:	Rosen/Direct
Sponsoring Party:	Public Counsel
Case No.:	EM-96-149

DIRECT TESTIMONY ON MARKET POWER

OF

DR. RICHARD A. ROSEN

Submitted on Behalf of
the Office of the Public Cousel

UNION ELECTRIC COMPANY

Case No. EM-96-149

November 26, 1996

Tellus Institute
11 Arlington Street
Boston, MA 02116-3411
Tel: 617/266-5400
Fax: 617/266-8303

110.

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of the application of Union Electric Company for an order authorizing: (1) certain merger transactions involving Union Electric Company; (2) the transfer of certain assets, real estate, leased property, easements and contractual agreements to Central Illinois Public Service Company; and (3) in connection therewith, certain other related transactions.	))))))	Case No. EM-96-149

AFFIDAVIT OF DR. RICHARD A. ROSEN

STATE OF Massachusetts)
) ss
COUNTY OF Suffolk)

Dr. Richard A. Rosen, of lawful age and being first duly sworn, deposes and states:

1. My name is Dr. Richard A. Rosen. I am a senior research scientist at Tellus Institute. I am a consultant retained by the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony consisting of pages 1 through 54 and Exhibit RAR-1.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Richard A. Rosen
Dr. Richard A. Rosen

Subscribed and sworn to me this 20th day of November, 1996.

David R. McCarthy
Notary Public

My commission expires Nov. 21, 2001.

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR POSITION AT TELLUS INSTITUTE.

A. I am a senior research scientist at Tellus Institute, as well as executive vice-president of the Institute. I am also director of the Institute's Energy Group.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resource, and environmental research. Within Tellus Institute, the Energy Group focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON TELLUS' EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. The Energy Group has had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue

requirements. Tellus Institute also has reviewed the prudence of many past supply planning decisions by utilities.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past sixteen years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec.

Due to my extensive regulatory experience in the public interest, as outlined above, in 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, within the last two years, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Administration, the National Association of Regulatory Utility Commissioners (NARUC), the New England Governors' Conference, and the National Council on Competition in the

Electric Industry. The remainder of my experience is summarized in my resume, which is attached as Exhibit RAR-1.

Q. HAVE YOU TESTIFIED ON OTHER MERGER CASES IN THE PAST?

A. Yes. I testified in the proposed merger of Central Illinois Public Service Company (CIPS) and Union Electric Company (UE) in Illinois Docket No. 95-0551. In that Docket, I testified on the balance of risks and rewards to ratepayers and stockholders from the merger.

I also recently testified before the Maryland Public Service Commission (Docket No. EC96-10-000) and before the Federal Energy Regulatory Commission (Docket No.8725) on behalf of the Maryland Office of People's Counsel regarding the proposed merger between Baltimore Gas & Electric Company (BGE) and Potomac Electric Company (PEPCO).

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. In this case, I am testifying on behalf of the Missouri Office of the Public Counsel (OPC).

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS DOCKET?

A. No, I have not testified previously in this docket.

Q. WOULD YOU PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY IN THIS DOCKET.

A. Yes. The purpose of my testimony in this docket is to respond to the Missouri Public Service Commission's (PSC's) request, as put forth in its September 25, 1996 Order, for additional information concerning various issues related to market power. UE and CIPS have proposed to merge, and for each to become wholly-owned subsidiaries of Ameren Corporation (Ameren). The Commission has requested that parties to this docket address the potential ability of Ameren to exercise market power, if the merger is approved. Specifically, the PSC has requested that each party define the relevant markets for UE today and for Ameren, if the merger is approved, that are appropriate for assessing market power. Relevant markets that reflect full-scale wholesale and retail competition should

also be addressed, as should entry barriers in possible post-merger markets. Furthermore, the PSC has requested that each party set forth how the potential exercise of market power by Ameren could be measured or tested. Finally, the PSC has requested that each party consider whether market power could be mitigated by: 1) an Independent System Operator (ISO), 2) a regional transmission tariff, 3) expanding transmission capability, and/or 4) other measures. My testimony responds to the Commission's request for additional information on these issues related to market power.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into seven sections, as follows:

II. Summary of Conclusions and Recommendations
III. The Role of the Missouri PSC in the Proposed UE-CIPS Merger Case
IV. Market Power in the Electric Utility Industry: An Overview
V. Defining the Relevant Markets
VI. Measuring Market Power
VII. Mitigating Market Power
VIII. Conclusion

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS.

A. My findings and conclusions are summarized as follows:

- It appears that the proposed UE-CIPS merger will not increase the Applicants' ability to exercise market power at the wholesale or retail levels *under the current Federal and State regulatory frameworks* to any significant degree. Therefore, approval of the proposed merger should not be denied on the basis of increased market power. Nonetheless, I am concerned that under a fully competitive, deregulated wholesale market, the Applicants could potentially exercise greater market power than they otherwise could absent the merger. Similarly, I am concerned that under a fully competitive, deregulated retail market, the Applicants could potentially exercise greater market power than they otherwise could absent the merger.

- On behalf of UE, Mr. Frame has not examined the market power implications of the proposed merger under the assumption that **full-scale wholesale competition** is introduced in the Missouri-region. Mr. Frame's testimony before FERC and before the Missouri PSC does not seem to recognize the possibility of a deregulated wholesale generation market.

- On behalf of UE, Mr. Frame has not examined the market power implications of the proposed merger under the assumption that **retail competition** is introduced in Missouri. Mr. Frame's reason for not performing this examination is that he does not know how retail competition would be designed and implemented in the State. Therefore, he does not believe that the examination is feasible or desirable. I do not agree with Mr. Frame's justification for not carrying out this important analysis. It appears to me that Mr. Frame is trying to downplay the potential market power implications of the proposed UE-CIPS merger under retail competition, despite the fact that retail competition is a strong possibility in both Missouri and Illinois at some point in the future. Furthermore, UE has the burden of proof to demonstrate that the proposed merger is not detrimental to the public interest. By failing to examine the market power implications of the proposed merger under the assumption that either a deregulated wholesale market or retail competition is introduced in Missouri, UE has disregarded the Commission's specific request for such an examination.

- Relevant electric generation product markets differ from markets for other products in a number of critical and fundamental ways. Electricity can not generally be stored in significant quantities, it can not easily be substituted for in the short term, and it can only be transported along existing transmission lines which can not easily be expanded. Because of these distinct characteristics of electricity, electric generating systems typically comprise different types of units (i.e., baseload, cycling, peaking) which are designed to operate over different time

intervals and with different capacity factors in order to provide different electricity products. These different generating technologies form the basis for different sub-markets which can be further subdivided into short-, medium-, and long-term markets.

- The relevant electric generation product markets for UE today, and for Ameren, if the merger is approved, are the three unique sub-markets that I mentioned above, namely baseload, cycling, and peaking, each of which can be further divided into short-term, medium-term, and long-term markets, thus defining a total of nine product sub-markets that should be recognized as separate, unique, and non-substitutable in the market power analysis for the proposed UE-CIPS merger. One way to ascertain that they are distinct markets is from the fact that they have different prices.

- The relevant geographic markets in an open access transmission environment should be determined primarily by a detailed analysis of transmission costs, physical transmission constraints, and the generating capacity available at different locations that can actually compete. Consideration should also be given to how physical transmission constraints in the form of "load pockets" could create or maintain barriers to entry into the generation market, and to the role that load pockets might play in enhancing the potential abuse of market power in generation markets by the merged companies.

- The relevant geographic market for UE today and for Ameren, if the merger is approved, may be smaller than the "first tier markets" used by Mr. Rodney Frame in his market power analysis that he presented to FERC. According to Mr. Frame, participants in each such first tier market include (i) the hub or center utility, (ii) UE and/or CIPS premerger and Ameren post merger, (iii) any other party interconnected with the hub utility, and (iv) any utility not already included which can be accessed via the merged firm's open access tariff. Mr. Frame's definition of the relevant geographic market fails to account for transmission prices, physical transmission constraints, transmission ownership and control, and the generating capacity available at different locations that could actually compete. Factors such as these would tend to reduce the size of the relevant geographic market.

- The conventional Herfindahl-Hirschman Index (HHI) test is far too simplistic a test to be able to adequately measure market power **in the electricity industry**. While the HHI test may be a recognized and well-accepted market concentration test used by the Department of Justice and Federal Trade Commission to analyze merger cases in other industries, it is not an appropriate measure for analyzing market power in the electric industry. This is true from both a mathematical and a theoretical perspective. The HHI is mathematically incapable of taking into account existing unique characteristics of the electric industry, or potential future changes in the structure of the electricity market. Therefore, there is no way of knowing whether an HHI value of 1800, 1000, or some other value, should be interpreted as indicative of the starting point for a highly concentrated market

under wholesale or retail competition because no adequate empirical studies of the electric utility industry have ever been done to validate that assumption.

- The Missouri PSC should carefully consider the extent to which, if at all, the HHI market concentration test should be relied upon to analyze the potential market power in the proposed UE-CIPS merger, as well as in other electric utility mergers, based on the criticisms of the HHI presented in my testimony.

- Possible measures for mitigating *vertical* market power include open-access tariffs, independent transmission system operators (ISOs), transmission expansion, functional unbundling, and generation divestiture. The only apparent measure for mitigating *horizontal* market power in the generation market is to require utilities to divest their generation assets into enough separate generation companies such that each one has sufficiently limited market concentration in relevant markets. Vertical and horizontal market power in the aggregator market could be mitigated by 1) requiring distribution companies to provide *all* aggregators with non-discriminatory access to customer billing and end-use data, 2) placing the aggregator function of a vertically integrated utility into a subsidiary, and 3) disallowing the affiliate aggregator of the once-vertically integrated utility to use the name of said utility.

- The Missouri PSC should require the Applicants to carefully and thoroughly assess the potential ability of the merged companies to abuse vertical and especially horizontal market power in price deregulated retail generation markets. If market power under either of retail competition proves to be a problem based on this analysis, then appropriate mitigation measures will have to be mandated by the PSC prior to or while establishing retail competition.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE MISSOURI PSC BASED ON YOUR FINDINGS AND CONCLUSIONS?

A. Based on my findings and conclusions summarized above, I recommend that the Missouri PSC require UE and Ameren, if the proposed merger is approved, to fully cooperate with the PSC in assessing their potential ability to exercise market power under both *a deregulated wholesale market scenario* and under *full-scale retail competition*, and in implementing *all* effective mitigation measures deemed to be appropriate by the PSC. Specifically, the Missouri PSC should require the Applicants, which bear the burden of proof in this case, to carefully and thoroughly analyze whether the ability of the merged utilities to exercise market power in relevant markets under deregulated wholesale or retail competition is likely to be significantly greater than the joint impact of the two individual utilities in exercising market power in relevant markets under wholesale and retail

competition. If the Commission's evaluation indicates that when generation is deregulated under wholesale or retail competition, there is likely to be significant market power due to the merged companies, then the PSC should identify and implement all appropriate measures to mitigate Ameren's market power *prior* to the commencement of the deregulation of generation and/or retail competition. In short, any significant level of market power in the region could be detrimental to Missouri's public interest under future restructuring of the electric industry, and thus the Commission should play a proactive role in the development of fully competitive wholesale and retail electricity markets in the State.

Despite Office of the Public Counsel's determination that, under certain scenarios, there may be an increase in UE's or Ameren's market power which, by itself, may be detrimental to the public interest, Public Counsel still supports the Stipulation and Agreement and believes it is in the public interest.

III. THE ROLE OF THE MISSOURI PSC IN THE PROPOSED UE-CIPS MERGER CASE

Q. IN GENERAL, WHAT SHOULD THE ROLE OF THE MISSOURI PSC BE IN EVALUATING THE PROPOSED UE-CIPS MERGER?

A. In general, the role of the Missouri PSC in evaluating the proposed UE-CIPS merger should be to ensure that the proposed merger will be in the public interest, and that the prices paid by retail customers will be just and reasonable. These determinations must be made assuming both the State's current regulatory framework, as well as potential future wholesale and retail competition scenarios that may occur in Missouri. In my opinion, such deregulation scenarios are quite likely given federal and state initiatives to introduce wholesale and retail competition into the electric industry.

Q. SPECIFICALLY, WHAT SHOULD THE ROLE OF THE MISSOURI PSC BE IN EVALUATING THE PROPOSED UE-CIPS MERGER?

A. As I indicated in Sections II and V of my testimony, it appears the proposed UE-CIPS merger will not significantly increase the Applicants' ability to exercise market power at the wholesale or retail levels *under the current Federal and State regulatory frameworks*. However, UE has not examined the market power implications of the proposed merger under the assumption that retail competition is introduced in Missouri. Therefore, the Missouri PSC should require the Applicants to carefully and thoroughly analyze whether the ability of the merged utilities to exercise market power under retail competition is likely to be greater than the ability of each individual utility to exercise market power under retail competition. If the Commission's evaluation of the Applicants' analysis indicates that under retail competition, there is likely to be a significant increase in market power due to the proposed merger, then the PSC should identify and implement all appropriate measures to mitigate the market power *prior* to commencing retail competition.

Q. DO YOU AGREE WITH THE POSITION THAT IT IS APPROPRIATE FOR FERC TO BE THE PRIMARY FORUM FOR THE EXAMINATION OF ANY MARKET POWER IMPLICATIONS OF THE PROPOSED MERGER?

A. No, I do not agree with the position taken by UE witness Ms. Maureen Borkowski and by Missouri PSC Staff member Mr. Mark Oligschlaeger that "since any market power implications of the UE/CIPSCO transaction extend well beyond the Missouri jurisdiction, it seems appropriate for the FERC to be the primary forum for the examination of these issues." (Exhibit No.9, Rebuttal Testimony of Mark Oligschlaeger, page 46).

Just as "[m]arket power is a current concern to FERC due to its regulatory initiatives to encourage competition in the wholesale generating market" (Exhibit No.9, Rebuttal Testimony of Mark Oligschlaeger, page 44), it should also be a current and equally important concern to the Missouri PSC due to FERC's regulatory initiatives to encourage greater wholesale competition, and due to the likelihood that there could be retail competition in the future in the State. The Commission, in fact, recognizes this latter point in its September 25, 1996 Order: "Because market power might be of greatest concern to Missouri customers if full retail competition were authorized throughout the Ameren market area, assumptions based upon that scenario should be included [in the parties' analyses of Ameren's potential market power]." (page 3). Furthermore, in a statement made at the annual NARUC conference by Commissioner Massey of FERC on November 20, 1996, he expressed his opinion that state commissions should analyze the impact of proposed mergers on regional power markets. Finally, FERC Assistant General Counsel Stephen Angle has said that if FERC decides that it must take retail competition into account, it could either inquire into retail competition effects or defer to the states. He stated that "whether raised by the states alone or also by FERC, the proponents of a merger can expect to be called upon to explain how their proposal will be consistent not only with effective wholesale but also effective retail competition."[1]

Q. HOW SHOULD THE MISSOURI PSC'S EVALUATION OF AMEREN'S POTENTIAL MARKET POWER DIFFER FROM FERC'S EVALUATION?

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[1] "FERC: Evolving Face of Utility Mergers Complicates its Merger Policy Review." *Electric Utility Week*. November 18, 1996: page 6.

A. The Missouri PSC's evaluation of Ameren's potential market power should be made from the perspective of the State's *retail* customers, whereas FERC's evaluation would presumably be made from the perspective of the nation's *wholesale* customers. This means that the PSC should evaluate the effects of the proposed merger in both wholesale and retail competitive markets, since retail customers will be impacted by the prices in both markets. "The proposed SCE/SDGE merger was rejected by the California Public Utilities Commission based in large part on anti-competitive effects in wholesale markets, and the Wisconsin and Minnesota commissions have announced hearings on the competitive effects in wholesale markets of the NSP/WEPCO merger."[2]

Furthermore, to a great extent, FERC tends to focus on analyzing *vertical* market power because the operation of utilities' transmission systems will impact the development of truly competitive wholesale generation markets. Hence, FERC tends to focus on transmission operation, access, transfer capability, congestion, and pricing as means to mitigate vertical market power in the wholesale generation market.

Though FERC's policies may also mitigate vertical market power in the retail generation market, none of FERC's efforts are *explicitly* designed to address market power issues at the retail level. This is the responsibility of the state regulatory commissions. Therefore, the Missouri PSC should evaluate the implications of vertical and horizontal market power resulting from the proposed merger on retail consumers. I believe that the Missouri Commission should place a significant amount of its time and effort into evaluating horizontal market power because this type of market power will be critical to the success or failure of wholesale generation markets and retail competition, and there is still much to learn about how to accurately measure it and effectively mitigate it.

Q. DID THE MISSOURI PSC EXPLICITLY MENTION THE NEED TO ADDRESS HORIZONTAL AS WELL AS VERTICAL MARKET POWER IN ITS SEPTEMBER 25, 1996 ORDER?

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[2] Frankena, Mark. "FERC Must Fix Its Electric Utility Merger Policy." *The Electricity Journal.* Volume 9, Number 8: page 34.

A. No, the Missouri PSC did not explicitly mention the need to address horizontal as well as vertical market power in its September 25, 1996 Order. However, it is essential that the PSC and all of the parties responding to the Order consider both forms of market power. Parties may tend to overlook issues related to *horizontal* market power because the Commission's Order mentions market assumptions about transmission access, transfer capability, transmission congestion, and transmission pricing, and market power mitigation measures such as ISOs, transmission tariffs, and transfer capability expansion -- all of these concepts relate to *vertical* market power, to a large extent. Horizontal market power should be given equally serious consideration.

IV. MARKET POWER IN THE ELECTRIC UTILITY INDUSTRY: AN OVERVIEW

Market Power Defined

Q. PLEASE DEFINE MARKET POWER IN GENERAL.

A. Market power can be generally defined as the ability of a particular seller or buyer, or group of sellers or buyers, to influence the prices of a product in a market, or to create or maintain effective barriers to entry into the market. The ability of a particular seller or group of sellers to profitably maintain prices above competitive levels for a significant period of time can reduce economic efficiency, because the resulting prices do not reflect an accurate societal valuation of the use of these resources given the demand and supply of such resources. High prices stemming from the exercise of market power cause an inefficient transfer of wealth from the consumer to the producer.[3]

Market power can exist in two general forms: *vertical* and/or *horizontal*. It is often hard to characterize a company as simply having just vertical or horizontal market power. Often a company, or the merging of two companies, can have elements of both.

Q. PLEASE DEFINE VERTICAL MARKET POWER.

Vertical market power can arise from the ownership or control of more than a single step in the process of production and delivery of a particular product. Control of vertically integrated assets can result in barriers to entry if an entity at one stage of the production and delivery process gives preferential treatment to an affiliated entity operating at another stage of the production and delivery process.

In the electric utility industry, vertical market power generally refers to a single utility controlling generation, transmission, and distribution functions in a specific geographic market. Vertical market power abuse can arise if, for example, 1) a transmission system operator gives priority to affiliated generation assets in dispatch and transmission, 2) a company uses control of the transmission network to insist that wholesale customers embedded in their service territory buy their electricity from the

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[3] Department of Justice/Federal Trade Commission Horizontal Merger Guidelines, 1992.

company rather than from alternative generation sources that would need to wheel the power over the company's transmission lines, and/or 3) a company buys power from other generation sources and then resells it at inflated prices to wholesale customers, reflecting its monopoly power over the essential transmission network.

Q. WHAT IS HORIZONTAL MARKET POWER?

Horizontal market power can take place at any level of the production chain from inputs to final output as a consequence of, for example, there being a very small number of competing sellers and significant barriers to entry at that horizontal level. Horizontal market power problems may also arise when there are vertical control relationships between producers at two or more horizontal levels (Paul A. Joskow, *Horizontal Market Power in Wholesale Power Markets*, August 1995). However, the most common type of horizontal market power is when a single competitor or a small group of competitors owns or controls most of the competitive resource at a particular level of production.

In the electric industry, the major present and future concern with horizontal market power is at the generation level, especially since the generation market is likely to be deregulated in the next five to ten years. Most analysts believe that transmission and distribution will continue to be regulated.

Q. COULD VERTICAL AND HORIZONTAL MARKET POWER ALSO BE A PROBLEM AMONG AGGREGATORS UNDER RETAIL COMPETITION?

A. Yes, under retail competition, vertical and horizontal market power could be exercised in aggregator (retail merchant) markets, just as in generation markets. For example, the aggregator functions of existing local utilities would have a distinct advantage over new independent aggregators because they would have access to historical and on-going customer billing and end-use data for the customers who the utility is currently serving; they could receive preferential treatment from the generation, transmission, and distribution functions of the utility; and they would have instant customer loyalty because presumably they would have the same name as the existing utility. These advantages for aggregators of existing utilities would serve as barriers to new aggregators trying to enter

the market. (I will discuss mitigation measures for market power at the generation and aggregator levels in Section VII of my testimony.)

Q. WHY IS MARKET POWER GENERALLY A CONCERN IN THE ELECTRICITY INDUSTRY?

A. Electric utilities were once thought to be natural monopolies[4], and thus were given exclusive franchise territories in exchange for being highly regulated based on cost-of-service principles. Today, while transmission and distribution continue to be considered natural monopolies, the same no longer applies to the generation sector. Modestly sized generation units owned by independent generators are now able to compete with large, capital intensive utility-owned plants. Similarly, the aggregator function is no longer considered to be a natural monopoly, since aggregators should be able to seek out a low-cost mix of power contracts from competing generators and resell power packages to retail consumers.

As the industry becomes increasingly competitive at the wholesale generation level, and retail competition looms on the horizon, the issue of market power (both vertical and horizontal) is at the forefront of many electric industry restructuring investigations around the country. The central concern is whether price deregulation of the generation market could result in the exercise of market power by a single utility or several prominent utilities in a particular region. Another concern that has not yet become central is whether a deregulated aggregator market could result in the exercise of market power by a prominent utility in a particular region.

The Exercise of Market Power Under Existing Regulation

Q. IS THE POTENTIAL FOR MARKET POWER ABUSE A CONCERN UNDER EXISTING COST-OF-SERVICE REGULATION?

A. Yes, both horizontal and vertical market power abuse can be exercised in wholesale generation markets, under existing cost-of-service regulation.

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[4] A set of products is characterized by natural monopoly when a single firm can provide all of the output of all of the products at lower total cost than could be achieved by more than one firm.

Q. PLEASE EXPLAIN HOW VERTICAL MARKET POWER CAN BE EXERCISED UNDER THE PREVAILING INDUSTRY STRUCTURE.

A. Under the current industry structure, where electricity prices are regulated on a cost-of-service basis by FERC at the wholesale level, and by a state commission at the retail level, a vertically integrated utility can potentially exercise vertical market power in the generation market since it has ownership and control of transmission networks. Furthermore, utilities can exercise vertical market power for the following reasons, as identified by the National Independent Energy Producers (NIEP):

- Utilities have an advantage over independent power producers (IPPs) in determining the need for new generating capacity;

- Utilities are subject to more lenient accountability, such as of forfeiture of security deposits, project rights or other penalties, for missed deadlines and other non-performance than are IPPs;

- Utilities have an advantage over IPPs in the availability of eminent domain powers and procedures;

- Utilities have an advantage over IPPs in the availability of ratepayer funds (i.e., which finance the utility's assets and employees) in the competitive bidding process;

- Entry into power pools has been limited, for the most part, to utilities only -- the nation's power pools are only beginning to open up to IPPs.

In addition to the above, the NIEP describes a number of other ways in which vertically integrated utilities have a distinct advantage over independent generators in the prevailing industry structure. In sum, the NIEP states that:

> "...the development of an industry structure with vertically integrated utilities holding exclusive franchises (has) created a system of statutes and regulations which favors the incumbent utility and disfavors newcomers. This system remains entrenched today ..."(NIEP, *Is Competition Here? - An Evaluation of Defects in the Market for Generation*, April 26, 1995, pg. 3).

As a result of vertical market power, there can be significant barriers to entry into generation markets -- thus, also leading to the existence of horizontal market power.

Q. PLEASE EXPLAIN HOW HORIZONTAL MARKET POWER CAN BE EXERCISED UNDER THE PREVAILING INDUSTRY STRUCTURE.

A. Horizontal market can be abused under the prevailing industry structure if, as described above, there are barriers to entry in the generation market such that the utility can charge higher than competitive power prices. However, whether horizontal market power is exercised such that a utility can increase prices to its customers above cost-of-service levels is not relevant under the current industry structure, since prices are regulated by FERC and/or state commissions on an embedded cost basis. Nonetheless, by keeping owners of lower priced generation out of the market, horizontal market power can lead to a higher cost mix of generation for ratepayers than otherwise would have been the case, even under current regulatory practices.

Market Power and Electric Utility Mergers

Q. WHY IS MARKET POWER AN IMPORTANT CONCERN IN THE CONTEXT OF AN ELECTRIC UTILITY MERGER?

A. The merging of two electric utilities could accentuate potential market power problems if the physical and/or financial attributes of the two utilities together provide the newly formed entity with the means to increase, and maintain, electricity prices above competitive levels. Higher prices for consumers would clearly not be in the public interest. The merger applicants have the burden of proof to demonstrate that the proposed merger is not detrimental to the public interest

Q. PLEASE BRIEFLY EXPLAIN HOW MARKET POWER IS MEASURED IN THE CONTEXT OF AN ELECTRIC UTILITY MERGER.

A. In the case of vertical market power, there is no formal method (e.g., a mathematical index) traditionally used to determine whether, and to what extent, market power may exist. Transmission ownership by utilities and the absence of open access provisions in the past, as well as physical transmission constraints, have served to identify vertical market power in the form of various institutional and contractual barriers to entry to non-utility generators. Quantifying vertical market power in a particular region would require a careful historical analysis of attempts by independent power producers to break into the

industry in the particular region, or a similar analysis of the ability of utilities with excess generation capacity to wheel to other wholesale markets.

The conventional method for assessing the potential degree of horizontal market power in a particular market resulting from a merger is based on the traditional antitrust approach employed by the Department of Justice (DOJ) and the Federal Trade Commission (FTC). This approach, which usually involves the application of the Herfindahl-Hirschman Index (HHI) test, measures the market concentration in an appropriately defined product and geographic market. I discuss and critique this approach in Section VI of my testimony.

Q. PLEASE SUMMARIZE THE DOJ/FTC HORIZONTAL MERGER GUIDELINES.

A. The 1992 Horizontal Merger Guidelines jointly issued by the DOJ and FTC describe the analytical process that the DOJ/FTC normally employs in analyzing mergers, including assessing whether:

1. The merger would significantly increase concentration and result in a concentrated market, properly defined in terms of the product and geographic region, and properly measured.

2. The merger, in light of market concentration and other factors that characterize the market, raises concern about potential adverse competitive effects.

3. Entry by potential competitors would be timely, likely and sufficient either to deter or to counteract the anti-competitive effects of concern.

4. Any efficiency gains (e.g., economies of scale) could be reasonably achieved by the parties through other means.

5. But for the merger, either party to the transaction would be likely to fail, causing its assets to exit the market. *(DOJ/FTC 1992 Horizontal Merger Guidelines)*

The basic framework for assessing the above factors allows the DOJ/FTC to determine whether a merger is likely to create or enhance horizontal market power, or to facilitate its exercise.

Q. HOW HAS FERC GENERALLY EVALUATED MERGER PROPOSALS IN THE PAST?

A. Over the past few decades, FERC has used the so-called Commonwealth Edison test to evaluate merger proposals.[5] Among the six merger guidelines used in the evaluation of a proposed merger[6], is the requirement that the merger not have an adverse impact on competition in the geographic market of interest. Generally, in merger cases where FERC has determined that there is a potential for vertical market power abuse, it has required that the merging companies provide open access transmission service to competitive wholesale suppliers. This was the case in FERC's Order in the Utah Power & Light Co., PacifiCorp and PC/UP&L Merging Corp (47 FERC,¶61,209, 1989 and 62 FERC ¶61,018, 1993), in which FERC required the new merged entity to provide firm (uninterruptible) wholesale transmission service at cost-based rates to any wholesale generation suppliers. In addition, FERC required the new entity to set aside a portion of its transmission capacity for five years for utilities dependent on its transmission lines for access to their source of power or their customers.

Q. NOW THAT FERC HAS ADDRESSED OPEN-ACCESS AND COMPARABLE PRICING IN ORDER 888, WILL THESE PROVISIONS SUFFICIENTLY MITIGATE VERTICAL MARKET POWER?

A. The extent to which FERC's open-access and comparable pricing provisions will help mitigate vertical market power abuses will depend upon a number of factors, which I discuss in Section VII of my testimony.

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[5] Commonwealth Edison Co., 36 FPC 927 (1966), aff'd sub nom. Utility Users League v. FPC, 394 F.2d 16 (7th Cir. 1968), cert. denied, 393 U.S. 953 (1968).

[6] The six Commonwealth factors include 1) the proposed merger's effect on operating costs and rate levels, 2) accounting treatment, 3) the reasonableness of the purchase price, 4) coercion by the acquiring utility, 5) the merger's effect on competition, and 6) the merger's effect on the effectiveness of State and Federal regulation.

V. DEFINING THE RELEVANT MARKETS

Defining the Relevant Markets

Q. ACCORDING TO THE DOJ/FTC'S BASIC CONCEPTUAL FRAMEWORK DESCRIBED ABOVE IN SECTION IV, WHAT IS THE FIRST STEP IN ANALYZING HORIZONTAL MARKET POWER?

A. According to the DOJ/FTC's basic conceptual framework, the first step is to define the relevant markets in which competition takes place and to identify the suppliers that actually or potentially could compete with one another to supply customers in these relevant markets if prices were to rise by a small but significant amount. Each relevant market should be defined in terms of its *product* and its *geographical* boundaries. Relevant markets are defined from the perspective of pertinent groups of buyers.

Defining the Relevant *Product* Markets

Q. ARE THE RELEVANT PRODUCT MARKETS EASILY DEFINED IN THE ELECTRIC GENERATION INDUSTRY?

A. No, in the electric generation industry it is not easy to define relevant product markets. Relevant product markets should aggregate good substitutes, and should consider products that are not good substitutes as being in separate relevant product markets. However, the degree to which electric products and services can be substituted for one another is not always clear. This fact is recognized by UE witness Mr. Rodney Frame in his statement that "there are generally not clear breaks in the 'chain of substitution', [such that] the exercise of judgment by the analyst is important." (Direct Testimony of Rodney Frame, November 1, 1996, Schedule 1, page 17 of 158). Economist Paul J. Joskow also recognizes this challenge:

> "Defining precisely which products and which geographically dispersed suppliers are in the market versus which are not in the market is nearly impossible, since defining the relevant product markets and the gaps in the chain of substitutes for those markets may not exist. Moreover, existing contractual or regulatory commitments can affect the appropriate consideration of competitive significance of different suppliers. As a result, it is necessary to examine market power indicia using alternative definitions

> of the relevant market to understand better how sensitive the analysis is to small changes in definitions of relevant markets and geographic areas." (Paul L. Joskow, *Horizontal Market Power in Wholesale Markets*, August 1995, pg.18).

In addition, William G. Shephard, an anti-trust economist, stated in a recent article that "[e]lectricity products are complex, not simple. This is especially true in the markets for long-run full-requirements power. The package of services is complicated and subject to a variety of controls and conditions."[7]

Q. HOW COULD ONE BEGIN TO DEFINE RELEVANT PRODUCT MARKETS IN THE ELECTRIC GENERATION INDUSTRY?

A. One could begin by looking at electric generating systems. Electric generating systems typically comprise different types of units, which are designed to operate over different time intervals and with different capacity factors. In accordance with these criteria, electric capacity and energy can be loosely categorized into the following *sub-markets*: baseload, intermediate, and peaking. For example, coal-fired units typically provide baseload power, since they are relatively inexpensive on a variable cost basis, can run over long periods of time, and can not easily be turned on and off in response to changing demand for electricity. Nuclear units and hydroelectric units also typically supply baseload electricity. Intermediate units, or "cycling" units as they are sometimes called, can also operate over fairly long stretches of time. However, they are typically more expensive than baseload plants on a variable cost basis. Intermediate units, which can be turned on and off more easily, are dispatched to meet demand for electricity when it can not be met economically by baseload units. Examples of intermediate units are oil- and gas-fired steam units, and gas-fired combined cycle units. Finally, peaking units are only dispatched when demand is close to its peak value, and for providing spinning reserves and similar ancillary services. Peaking units, which are expensive to operate, but which can be turned on and off quickly, may only run for a couple of hours at a time, and for a few hours during the year. Gas-fired combustion turbines typically provide peaking power because

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[7] *Applying Anti-Trust to Mergers in the Electricity Industry*, Appendix A.

their capital cost (fixed cost) is relatively low, and they generally provide capacity reserves.

In addition to capacity and energy, products in the electric generating industry include a multitude of ancillary services, and can be under firm and nonfirm contracts of varying durations.

Q. ARE THESE SUB-MARKETS FAIRLY DISTINCT?

A. Yes, these sub-markets are fairly distinct, in that they are not substitutable for each other, even though the boundaries between them are often not sharp. Joskow supports this point by stating:

> "The definition of the relevant product markets in evaluating market power in electricity power markets should depend on a variety of physical, economic and institutional attributes that are particular to electricity and the way the industry is structured and regulated. As a result, under prevailing institutional arrangements, it will not generally be appropriate simply to define "electricity" or "generating capacity" as the relevant product market. Nor will it necessarily make sense to calculate "market shares" and seller concentration ratios simply by adding up all of the generating capacity and energy. Some of this capacity and energy may compete on the supply-side in the relevant market. Some may compete on the demand-side (for vertically integrated firms), acting as competitive substitutes for those utilities that are buyers rather than sellers in wholesale markets. And some may not compete at all in certain relevant product markets because of pre-existing regulatory or contractual commitments or the economic attributes of particular supply technologies. Moreover, some of the relevant institutional factors may change over time, and the definition of the relevant markets and/or who competes in them may change as well." [emphasis added](id. at 20)

Joskow's reference to the "economic attributes of particular supply technologies" specifically addresses the need to define the unique sub-markets in the electricity generation market that I mentioned above (namely baseload, cycling, and peaking). These sub-markets can be further divided into short-term, medium-term, and long-term markets, thus defining a total of nine product sub-markets that should be recognized as separate, unique, and non-substitutable in the market power analysis for the proposed UE-CIPS merger. One indication that they are non-substitutable is that the price of electricity in each of these various sub-markets is likely to be quite different from each other.

Furthermore, that is true before even distinguishing between firm and nonfirm power, or between regions, or before including competitive ancillary services. For example, long-term firm peaking power could cost 10.0 cents per kWh, whereas short-term baseload power could cost only 3.0 cents per kWh.

Q. PLEASE COMMENT ON JOSKOW'S POINT CONCERNING HOW "THE RELEVANT INSTITUTIONAL FACTORS MAY CHANGE OVER TIME."

A. In general, changes in the electric industry will likely occur in three stages. The implementation of open-access transmission tariffs will occur in the short term, and an ISO and/or a power exchange ("poolco") may be established in the medium term, in accordance with FERC Order 888, which encourages the further development of wholesale competition. In the long term, it is likely that the generation market will be deregulated, either through the functional unbundling or through the actual divestiture of utilities' generation assets, and that competition at the retail level will be permitted. The introduction of retail consumers into competitive electric generation markets will certainly affect how relevant product markets are defined.

Joskow provides a number of specific examples of how changes to the electric industry structure might affect the definition of the relevant electric generation product markets, including:

- The implementation of an ISO and/or a poolco would eliminate the traditional distinction between firm and nonfirm capacity and energy transactions;
- Physical trades and financial contracts of certain kinds (like baseload, cycling, and peaking) would be offered separately rather than bundled together; and
- Transition arrangements for existing generating capacity could affect the behavior of existing suppliers in the market.

Defining the Relevant *Geographic* Markets

Q. ONCE THE RELEVANT PRODUCT MARKET IS APPROPRIATELY DEFINED, WHAT IS THE NEXT STEP ACCORDING TO THE DOJ/FTC'S BASIC CONCEPTUAL FRAMEWORK FOR ANALYZING MARKET POWER?

A. The second key step in evaluating the conditions that could affect competition in an electricity market is to define the relevant geographic region of the market in which generators compete with one another. Generators located at different points should be aggregated into the same relevant geographic market when customers do or could economically turn to them as competing suppliers for their electricity needs, if the prices in each product sub-market were to rise by a small but significant amount.

Q. IN AN OPEN-ACCESS TRANSMISSION ENVIRONMENT, WHAT FACTORS WILL DETERMINE THE EXTENT OF THE RELEVANT GEOGRAPHIC MARKETS?

A. In an open-access transmission environment, the extent of the relevant geographic markets will be determined primarily by transmission costs and rate design, physical transmission constraints, and the generating capacity available at different locations to compete.

Q. HOW WILL TRANSMISSION COSTS AND RATE DESIGN HELP DETERMINE RELEVANT GEOGRAPHIC MARKETS?

A. Transmission prices will help to define relevant geographic markets by distinguishing the "radius of competition" for one product sub-market, such as peaking power, from another product sub-market, such as baseload power.

Q. PLEASE EXPAND UPON YOUR POINT THAT TRANSMISSION CONSTRAINTS WILL ALSO AFFECT THE BOUNDS OF RELEVANT GEOGRAPHIC MARKETS.

A. The provision of electricity by wholesale sellers to distribution utilities, or to retail customers in the case of retail competition, is often highly restricted, or potentially restricted, especially during times of peak demand, since electricity can only be transported along existing transmission lines. Transmission constraints thus raise fundamental issues concerning both horizontal market power -- in terms of appropriately defining geographic boundaries for a particular product market -- as well as those relevant

to the potential exercise of vertical market power, in terms of creating barriers to entry by non-utility or other utility generators. For example, the geographical region for peaking power may be much more highly restricted, relative to the location of a particular power plant, than the market for baseload power. This may be true because of the rate structure of transmission tariffs, if these tariffs are highly demand-related.

Q. PLEASE EXPLAIN HOW ELECTRICITY IS FUNDAMENTALLY DIFFERENT FROM OTHER PRODUCTS WITH RESPECT TO ITS TRANSPORTATION.

A. I will explain how electricity is fundamentally different from other products with respect to its transportation by comparing electricity to a product such as canned foods. Canned foods can be transported from factory to wholesaler, and from wholesaler to retailer, and from retailer to consumer, by a number of different modes of transport. The canned foods can be transported by air, sea, rail, road, or in person. In each of these modes of transport, there are numerous providers of the transport service, such that no providers are able to exercise market power. Furthermore, there are very few, if any, barriers to entry in each of these transport sub-markets. The competition between new market entrants and established providers also minimizes the extent to which market power can be exercised. This flexibility in transportation does **not** apply to electricity, which can **only** be transported along transmission lines. Furthermore, many of these transmission lines are severely constrained in various hours of the year, or would be if full-fledged retail competition were established. To further complicate this issue, these constraints depend upon which particular generating units are operating at a given moment in time. Thus, the rigidity of the transmission system, leading to transmission constraints, renders the transportation of electricity much more complicated than that of other products. Furthermore, the need for voltage and frequency stability accentuate this problem.

Q. HOW DO THESE TRANSPORTATION CONSTRAINTS RELATE TO THE POTENTIAL FOR HORIZONTAL MARKET POWER ABUSE IN THE ELECTRICITY GENERATING INDUSTRY?

A. The fact that electricity can only be transported along existing transmission lines is very relevant to the potential for horizontal market power abuse in the electric generating

industry. I can best illustrate this issue by once again comparing the electric generation industry to the canned food industry. In the canned food industry, there are very few, if any, **physical** constraints on the location from which one can buy one's product, whether one is the wholesaler or the ultimate consumer.[8] If the only canned food manufacturer in the region is much more expensive than canned food manufacturers elsewhere, there are no insurmountable **physical** reasons why the wholesaler in the region can not purchase canned food from a cheaper manufacturer outside the region, since the canned food can be transported in a number of different ways. The same argument applies to ultimate consumers purchasing their canned foods from different retail outlets. However, the example presented here of the canned food industry can **not** be generalized to the electric generation industry.

Q. PLEASE EXPLAIN WHY THE EXAMPLE OF THE CANNED FOOD INDUSTRY CAN NOT BE ADAPTED TO THE ELECTRICITY GENERATING INDUSTRY.

A. The reason why the example presented above can not be adapted to the electric generating industry is as follows. If an electricity consumer is located in a region where the price of electricity is relatively high, the consumer can not necessarily purchase electricity from a neighboring region where the price of electricity is lower (even allowing for new open access policies) due to possible transmission constraints, or "bottlenecks." Electricity can only be transported from one region to another if there is sufficient transmission capacity available in the existing network of transmission lines. Thus, the intra- and inter-regional transport of electricity may be severely limited relative to other products, such as canned foods, because of physical limitations in the transmission system, and the time frame for alleviating these constraints may be much longer. Furthermore, many of these constraints are not yet known because, in the past, most electricity has been consumed by customers of the same vertically integrated utility that generated the power. Under retail competition, this would no longer be true.

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[8] For example, traffic jams can be overcome by using other modes of transport, such as train or air freight.

Q. WHAT ARE THE IMPLICATIONS OF THESE POTENTIAL TRANSMISSION CONSTRAINTS FOR THE EXERCISE OF MARKET POWER BY GENERATING UNITS?

A. The implications of these potential transmission constraints for the exercise of market power by generating units are highly significant because the constraints limit the size of the region in which competition in generation can occur, and the degree to which it can occur. In regions of the country that are relatively isolated from the electric systems of other regions (i.e., where the transmission interconnections between regions are poor, or even non-existent), generating units would have a much greater ability to exercise market power. For example, consumers purchasing electricity from a system which is relatively isolated in terms of transmission would have fewer opportunities to purchase electricity from other electric systems. A 20,000 MW system may be able to import 4,000 MW, but not 20,000 MW, or even 12,000 MW. Thus, competition from generation located **externally** would be highly constrained under retail competition. Another way of thinking about this issue is that when there are transmission constraints, the effective number of firms competing in the electricity generating market is reduced. The extreme case of the combination of transmission constraints and strategically located generation facilities is known as a "load pocket."

Q. PLEASE ELABORATE ON THE ISSUE OF LOAD POCKETS.

A. Load pockets exist when, due to transmission system limitations, some generation *must* be operated within a particular region in order to continue the provision of reliable transmission service.[9] The strategic locations of these generation units relative to the transmission system create an inherent potential for abuse of market power in a deregulated generation market. These load pocket areas may not be susceptible to immediate entry of lower priced competitors because of siting and pricing constraints, and thus entry of competing generation in the near term may not be an option because of the need to upgrade transmission or build new generation (by a non-affiliated company) that

[9] New York Public Service Commission, Opinion and Order Regarding Competitive Opportunities for Electric Services. Case 94-E-0952.

could be profitable in that area. Furthermore, an ISO would not solve market power problems created by the existence of load pockets because load pockets represent a set of **physical** constraints on the extent to which generation markets can be competitive.

Q. HAS THIS MARKET POWER CONCERN BEEN RECOGNIZED BY UE?

A. Yes, this market power concern has been recognized by UE. In his Direct Testimony in this case, Mr. Rodney Frame states that:

> "it seems likely that the most important 'new' type of [market power] problem which would occur in a world of deregulation and retail competition will involve generation located close to load areas which 'must run' in order to preserve system reliability or to stay within thermal limits on paths into particular load pockets." (Direct Testimony of Rodney Frame, November 1, 1996, page 19).

Q. HAS MR. FRAME UNDERTAKEN AN ANALYSIS TO IDENTIFY THE EXISTENCE OF LOAD POCKETS IN UE'S SERVICE TERRITORY OR IN THE SERVICE TERRITORY OF AMEREN, IF THE PROPOSED MERGER IS APPROVED?

A. No, Mr. Frame states that he has not undertaken such an analysis because:

> "as a general matter such local problems, by their very nature, are not likely to be exacerbated by a merger even of adjacent utilities such as UE and CIPS. The local 'must run' problem is likely to pertain to generation located within a single utility's system and therefore will not be affected by a merger. Any such problems will exist whether or not the merger takes place and will not be exacerbated by it." (Direct Testimony of Rodney Frame, November 1, 1996, pages 19-20).

Q. DO YOU AGREE WITH MR. FRAME'S POSITION ON LOAD POCKETS?

A. I agree with Mr. Frame's position that if load pockets currently exist in an area where *only* UE or *only* CIPS owns generation, then they will exist whether or not the proposed merger takes place, and the market power that could be exercised in these load pockets by UE or CIPS under deregulation will not be exacerbated by the proposed merger if it is approved.

However, if load pockets currently exist in an area within which *both* UE and CIPS own generation, then I do not agree with Mr. Frame's position -- the potential for market power abuse in such load pockets under deregulation will be exacerbated by the

proposed merger if it is approved. Within a load pocket, competition in generation is either limited (during periods of low to moderate demand) or not possible (during periods of high demand), since relatively little of the generation in a load pocket can be replaced by competitors' generation from outside the load pocket in meeting demand. If there are load pockets in which *both* UE and CIPS own generation, and if the generation market is deregulated, then absent the proposed merger there will be some degree of competition among UE, CIPS, and outside competitors, at least during periods of low to moderate demand when a larger percentage of the demand can be met by outside competitors. However, if UE and CIPS are allowed to merge, then the degree of competition that they might have provided in a mutual load pocket will be lost. The market power that each, as individual companies, could exercise in a common load pocket will be intensified if the two companies are allowed to merge.

Q. HAS THE CONCERN ABOUT MARKET POWER ABUSE IN LOAD POCKETS BEEN EVALUATED BY ANY STATES?

A. Yes, in the State of New York, as part of the State's investigation of Competitive Opportunities Regarding Electric Service, the Public Service Commission Staff identified over 30 load pockets around the state, finding that they exist at various times within each utility territory (State of New York, Opinion Order No. 96-12, in Cases 94-E-0952 et al.). The report offered a number of suggestions for mitigating load pockets, including:

- Transmission system reinforcements (including line and equipment reinforcements, and readjustment of system flows);
- New generation (which would not change the existence of a load pocket, but could reduce or eliminate market power within that load pocket);
- Reconfiguration of loads;
- Demand-side actions (through a variety of means including increased equipment efficiency and reducing loads);
- Contractual methods (such as contracts for differences to remove any incentive for a generator to demand excessive prices through the exercise of market power, the execution of a contract for resources before competition starts, and providing for needed resources with an appropriate lead time);

- Continued regulation;
- Price caps (could be either absolute or formula-based, set by a regulator or by a contract);
- An increase in the number of owners of generation within the load pocket; and
- Mitigation of market power through steps taken by the independent system operator.

Q. SHOULD THE MISSOURI PSC REQUIRE THAT ALL LOAD POCKETS RELEVANT TO THE UE-CIPS MERGER BE IDENTIFIED?

A. Yes, the Missouri PSC should require UE to identify all load pockets in which it owns generation, including those in which *both* UE and CIPS own generation. Once all relevant load pockets have been identified, the Commission should determine which mitigative actions are appropriate for each load pocket prior to any form of deregulation of generation.

Q. WHAT CAN ONE CONCLUDE ABOUT HOW GEOGRAPHIC MARKETS SHOULD BE DEFINED IN A MARKET POWER ANALYSIS?

A. The appropriate definitions of the relevant geographic markets for purposes of assessing market power will be region-specific and are unlikely to be susceptible to a simple mechanical rule. Joskow notes that:

> "While the existence of power pools, RTGs, and reliability councils may have important implications for the appropriate definition of the relevant geographic market, the existence of these institutions per se will not necessarily define the boundaries between relevant geographic markets. A variety of physical, institutional and economic factors will affect the appropriate definition of the relevant geographic markets." (id. at 5)

Q. HOW DID UE DEFINE THE GEOGRAPHIC MARKETS OF AMEREN IN THE MARKET POWER ANALYSIS THAT IT PRESENTED TO FERC?

A. On behalf of UE, Mr. Rodney Frame considered first tier markets to address the potential for the exercise of market power in several electric generation product markets, including markets for short-term capacity and non-firm energy. Mr. Frame explains that:

> "There is a separate first tier market centered on each utility that is interconnected with UE, CIPS, or both. Participants in each such first tier market include (i) the hub or center utility, (ii) UE and/or CIPS premerger and Ameren post merger, (iii) any other party interconnected with the hub utility, and (iv) any utility not already included which can be accessed via the merged firm's open access tariff." (Direct Testimony of Rodney Frame, November 1, 1996, page 9).

Mr. Frame did not attempt to delineate the precise bounds of the relevant geographic markets for long-term capacity because he did not "believe that such an exercise would be particularly instructive for investigating important market power topics [related to the proposed UE-CIPS merger]." (Direct Testimony of Rodney Frame, November 1, 1996, page 13).

Q. IN YOUR OPINION, IS THE RELEVANT GEOGRAPHIC MARKET DEFINED BY MR. FRAME FOR UE TODAY AND FOR AMEREN, IF THE MERGER IS APPROVED, ACCURATE?

A. In my opinion, the relevant geographic market defined by Mr. Frame for UE today and for Ameren, if the merger is approved, may be too large. Mr. Frame's definition of the relevant geographic market fails to account for transmission prices, physical transmission constraints, transmission ownership and control, and the generating capacity available at different locations that could actually compete. Factors such as these would tend to reduce the size of the relevant geographic market.

Defining the Relevant Markets Assuming Entry Barriers

Q. PLEASE DESCRIBE HOW THE DOJ/FTC GUIDELINES ADDRESS THE ISSUE OF MARKET ENTRY.

A. The DOJ/FTC Guidelines include a market entry analysis to determine whether entry by potential competitors into a relevant market after a merger would be timely, likely and sufficient either to deter or to counteract any anti-competitive effects of the merger. The DOJ/FTC state that:

> "A merger is not likely to create or enhance market power, or to facilitate its exercise, if entry into the market is so easy that market participants,

> after the merger, either collectively or unilaterally could not profitably maintain a price increase above premerger levels."
>
> "In markets where entry is that easy (i.e., where entry passes these tests of timeliness, likelihood, and sufficiency), the merger raises no antitrust concern and ordinarily requires no further analysis." (DOJ/FTC 1992 Merger Guidelines, pg. 47)

Q. WHAT IF "EASE OF ENTRY" IS NOT THE CASE?

A. If a market is such that new firms can not easily enter it and compete with existing firms on equal footing, then the existing firms will have more opportunities to take advantage of any market concentration. The existing firm(s) in the market could engage in monopolistic or oligopolistic pricing schemes, which could only be undercut by new market entrants. Thus, as the ease of entry for new firms decreases, there is less likelihood of new firms entering the market and undercutting the monopolistic or oligopolistic prices set by the existing firms.

Summary

Q. PLEASE SUMMARIZE THE POINTS YOU HAVE ADDRESSED AND THE CONCLUSIONS YOU HAVE REACHED IN THIS SECTION.

A. Certainly. Relevant *product* markets in the electric generation industry can be loosely categorized into three *sub-markets* -- baseload, intermediate, and peaking. These can be further divided into short-term, medium-term, and long-term markets, thus defining a total of nine product sub-markets that should be recognized as separate, unique, and non-substitutable in the market power analysis for the proposed UE-CIPS merger. In the future, the introduction of full-scale wholesale and retail competition into the electric generation industry will certainly affect how relevant product markets are defined.

In an open-access transmission environment, the extent of the relevant *geographic* markets will be determined primarily by transmission costs and rate design, physical transmission constraints, and the generating capacity available at different locations to compete. The extreme case of the combination of transmission constraints and strategically located generation facilities is known as a "load pocket." The Missouri PSC should require UE to identify all load pockets in which it owns generation, including those

in which *both* UE and CIPS own generation. Once all relevant load pockets have been identified, the Commission should determine which mitigative actions are appropriate for each load pocket prior to any form of deregulation of generation.

The relevant geographic market defined by Mr. Frame for UE today and for Ameren, if the merger is approved, may be too large given that Mr. Frame's definition of the relevant geographic market fails to account for transmission prices, physical transmission constraints, transmission ownership and control, and the generating capacity available at different locations that could actually compete.

Finally, where barriers to market entry exist, abuse of market power by existing firms is more likely to occur.

VI. MEASURING MARKET POWER

The Herfindahl-Hirschman Index (HHI) Test

Q. WHAT IS THE CONVENTIONAL METHOD FOR ASSESSING MARKET POWER IN A RELEVANT MARKET AS A RESULT OF A MERGER?

A. As I mentioned in Section IV of my testimony, the conventional method for assessing the potential degree of horizontal market power in a particular market resulting from a merger is based on the application of the Herfindahl-Hirschman Index (HHI) test. This index measures the market concentration in a particular market. The DOJ/FTC Guidelines recommend using the HHI to determine whether a proposed merger would lead to excessive market concentration in each sub-market, which in turn increases the likelihood of the abuse of market power and non-competitive pricing.

Q. PLEASE DESCRIBE THE HHI IN MORE DETAIL.

A. The HHI provides a very simple measure of the potential abuse of market power by explicitly accounting for the number of firms in appropriately defined product and geographic markets and their respective market shares. It is calculated by simply summing the square of the market shares (expressed in percentage terms) of all firms in a particular market. For example, if there are four firms in a given market, each with an equal 25 percent market share, then the HHI for this market is equal to $(25^2+25^2+25^2+25^2)$, which equals 4 times 625, or 2,500. In the case of a perfect monopoly, in which there is only one firm owning 100 percent of the generation output in a particular market, the HHI assumes its maximum possible value of 10,000. Again, this is calculated by squaring the market share of each firm, which in the case of a perfect monopoly is equal to 100^2, or 10,000. Thus, for N *equal-sized* firms, HHI = 10,000 ÷ N.

In general, the DOJ/FTC consider a market "unconcentrated" if its HHI falls below 1,000, "moderately concentrated" if its HHI lies between 1,000 and 1,800, and "highly concentrated" if its HHI is in excess of 1,800. Note that an HHI of 1,000 is that produced by 10 equal-sized firms, and an HHI of 1,800 is that produced by 5.6 equal-sized firms.

Q. DO THE DOJ/FTC GUIDELINES GENERALLY SUPPORT APPLYING THESE HHI CRITERIA TO MERGER CASES IN *ALL* INDUSTRIES?

A. Yes, it appears that the DOJ/FTC Guidelines generally support applying these HHI criteria to the post-merger concentration of the relevant market, regardless of the type of industry. However, given the critical difference between the electric utility industry and other industries, this is a very serious limitation of the DOJ/FTC Guidelines. In my testimony, I do not comment on whether application of the HHI test is or is not appropriate for other industries. My comments concerning use of the HHI test are directed specifically at the electric industry.

Q. PLEASE DESCRIBE THE WEAKNESSES OF USING THE HHI AS A MEASURE OF MARKET POWER ABUSE IN THE ELECTRIC INDUSTRY.

A. There are many weaknesses of applying the HHI in attempting to measure the likelihood of market power abuse in the electric industry. While the HHI does take into account the market shares of individual firms in a particular market, and does assume higher values when firms in a market have greater market shares, one critical weakness of the HHI is that it still only provides a very crude indicator of market power, even when the markets and sub-markets are properly defined. This is because it can not take the details of the market structure into account. It can only measure market concentration, and only in a very simplistic way.

Q. HAS THIS CRITICAL WEAKNESS BEEN RECOGNIZED BY OTHERS IN THE ELECTRIC INDUSTRY?

A. Yes, this critical weakness has been recognized by others in the electric industry. Mr. Frame stated in his Direct Testimony before FERC that "there is no single measure of concentration, nor level of any such measure, that unambiguously differentiates between situations where market power is and is not likely to be of concern." (Direct Testimony of Rodney Frame, November 1, 1996, Schedule 1, page 19 of 158). As pointed out by Joskow:

> "Market shares and seller concentration ratios calculated by properly defined relevant product and geographic markets are convenient, but highly

> imperfect indicia of market power. They can be useful components of an analysis of market power if they are used properly and carefully, within the context of properly defined relevant markets and taking full account of the market, contractual and regulation institutions that characterize wholesale trade in electricity. Market share and seller concentration ratios may be completely meaningless outside of the context of properly defined relevant markets and the market and regulatory institutions that govern firm behavior." (emphasis added). Paul A. Joskow, *Horizontal Market Power in Wholesale Markets*, August 1995, pg. 6).

FERC staff have also stated that the HHI is only useful if the product and geographical market have been accurately identified.[10] In addition, as I discuss further below, there is nothing fundamental in economic theory that would lead to the conclusion that each firm's market concentration should be squared in order to weight it, as the HHI does, and then added to the squares of the market shares of each of the other firms in the relevant market. Thus, there is no theoretical basis for *squaring* each firm's market share, as opposed to, for example, *cubing* the market share of each firm. It may be the case that for the electric industry, cubing each firm's market concentration might provide a more accurate index of market power abuse. While the HHI increases for markets in which each firm has a relatively larger market share, the fact that it squares the market shares is based upon a completely ad hoc assumption, especially when this index is applied to measuring the potential for market power abuse *in the electric industry*. To my knowledge, there is no clear justification for squaring each firm's market concentration within each electricity sub-market. Similarly, there is no reason why the squares of the concentration should simply be added together. It is entirely possible that the squared concentrations for one firm might have greater influence on market power than the squared concentrations of another firm, due to institutional or locational factors. This type of effect could be modeled by allowing an index like the HHI to have coefficients multiplying the concentration terms which could be statistically fit to data.

Q. IN YOUR OPINION, IS THE HHI A USEFUL MEASURE OF POTENTIAL MARKET POWER ABUSE IN THE ELECTRIC GENERATION INDUSTRY?

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[10] Presentation of Stephen Angle, Assistant General Counsel for Hydroelectric and Electric Litigation at FERC in *EXNET*, March 4, 1996, Market Power Conference proceedings (p. 3).

A. The HHI is probably not a useful measure of potential market power abuse in an electric utility merger, even when applied to correctly defined product and geographic markets. The HHI does not take transmission constraints into account, except to the extent that these constraints are used to define the relevant geographic region. It does not factor in transmission pricing constraints between generating units and consumers, nor does it address the degree of substitutability of other products for electricity, nor the degree of ease of entry of new generation into each sub-market. However, the most important point is that a simple index like the HHI does not, and can not, take the unique features of the electric industry structure in each region into account. In the electric industry, sub-markets do not operate in isolation from each other, and yet the HHI for one sub-market can not take into account how that sub-market interacts with and affects other sub-markets. Put mathematically, the index has no "cross-terms" to account for these effects. A cross-term is a term like the square of a single company's market concentration for one product, whereby the market concentration of the company in one sub-market is multiplied by its market concentration in another sub-market. Thus, the HHI does not take the shape of the supply cost curve into account.

Q. PLEASE DISCUSS FURTHER WHY IT IS NOT APPROPRIATE TO APPLY THE DOJ/FTC GENERAL HHI CRITERIA (E.G., HIGH INDUSTRY CONCENTRATION IF ABOVE 1800) TO ELECTRIC UTILITY MERGER CASES.

A. It is not appropriate to apply the DOJ/FTC generic criteria that may have derived from experience with other industries to the electric utility industry and, therefore, to mergers in that industry because the structure of the electricity generation market is <u>fundamentally different</u> from most other commodity markets to which the HHI has been applied previously. The HHI, as it has been used in electric utility merger cases, does not adequately reflect the unique characteristics of electricity, nor the present and changing structure of the industry.

Thus, the specific numerical DOJ/FTC HHI breakpoints, or concentration criteria, that might be appropriate for how to interpret the significance of HHI values for other industries, must be considered to be a direct function of the specific market structure of each industry. In electric utility merger cases, this type of market power analysis to

determine which numerical breakpoints for the HHI might signal a real danger of market power has not, to my knowledge, ever been performed. Thus, I am not aware of any solid analytical basis specific to the electric utility industry that would allow one to conclude that an HHI result of 1,000 or lower in an electric sub-market indicates that there is little or no danger of market power abuse in that sub-market. And even if that quantitative analysis had been done for wholesale electricity markets as they are currently regulated at the state and federal levels, it certainly has not been done for fully deregulated generation markets, as will likely occur in the future, since they have never existed in the past. Thus, until more detailed market power studies using the HHI have been done for relevant sub-markets in the electric industry, there is not even a valid way to interpret any particular numerical values of the HHI in terms of their potential implications for the likelihood of abuse of market power. In fact, it is very likely that the same values of the HHI calculated for different electricity markets should have different interpretations, particularly if the size or type of one market is very different from that of another. For example, an HHI value of 1800 may imply no significant impact on prices in one sub-market (e.g., a 20,000 MW long-run baseload market), but a serious problem in another sub-market (e.g., a 5,000 MW short-term baseload market). One can not tell until the relevant studies for electric sub-markets are completed.

Q. DO OTHER ANALYSTS SHARE YOUR GENERAL CONCERN THAT ELECTRIC UTILITY MARKET POWER ANALYSES WILL HAVE TO BECOME MUCH MORE SOPHISTICATED TO BE USEFUL?

A. Yes, other analysts do share this general concern of mine. As George Hall from Putnam, Hayes and Bartlett stated in a presentation on March 4, 1996,[11] issues related to the relationship between market power and transmission constraints "are extremely difficult to analyze due to the nature of electric power systems and pools." (p. 6). Hall continued by stating that the "old style of merger analysis will have to be replaced by more sophisticated analyses of markets." (p. 7) Thus, he concluded that "how to analyze market power in today's electricity markets is a complex issue that has only begun to be explored.". (p. 9)

[11] *EXNET*, March 4, 1996, Market Power Conference proceedings.

In addition, Dr. Kevin Kelly, Deputy Director of Electric Power at FERC, stated on November 20, 1996 that market power analyses need to become more sophisticated to be useful to FERC.[12]

Assessing Market Power Under Existing And Future Market Structures

Q. HAS UE ASSESSED WHETHER OR NOT THE PROPOSED MERGER WOULD CREATE THE POTENTIAL FOR AMEREN TO EXERCISE MARKET POWER IN WHOLESALE GENERATION MARKETS *UNDER EXISTING REGULATION*?

A. Yes, on behalf of UE, Mr. Rodney Frame has assessed whether or not the merger would create the potential for Ameren to exercise market power in wholesale markets *under existing regulation*. This assessment was both qualitative and quantitative. Mr. Frame concluded that "the wholesale bulk power markets within which UE and CIPS operate already are competitive and that this will not be changed as a result of the merger." (Direct Testimony of Rodney Frame, November 1, 1996, Schedule 1, page 8 of 158). Furthermore, Mr. Frame concluded that "the filing by [UE and CIPS] of single-system tariffs should eliminate any residual concern that market power problems might arise as a result of the merger." (page 8 of 158).

Q. HAS UE ASSESSED WHETHER OR NOT THE PROPOSED MERGER WOULD CREATE THE POTENTIAL FOR AMEREN TO EXERCISE MARKET POWER IN RETAIL GENERATION MARKETS *UNDER EXISTING REGULATION*?

A. Yes, Mr. Frame has assessed whether or not the merger would create the potential for Ameren to exercise market power in retail markets under existing regulation. This assessment was qualitative. Mr. Frame examined "four types of retail competition which can be hypothesized to exist -- franchise competition, yardstick competition, locational or customer competition, and fringe area competition." (Direct Testimony of Rodney Frame, November 1, 1996, Schedule 1, page 95). Based on his examination, he "concluded that the merger does not create the potential for the exercise of market power in retail markets

[12] Remarks to NASUCA panel on transmission issues, San Francisco, California.

as the industry currently is structured." (Direct Testimony of Rodney Frame, November 1, 1996, page 18).

Q. HAS UE ASSESSED WHETHER OR NOT THE MERGER WOULD CREATE THE POTENTIAL FOR AMEREN TO EXERCISE MARKET POWER UNDER THE ASSUMPTION THAT FULL-SCALE WHOLESALE COMPETITION IS INTRODUCED IN GENERATION MARKETS IN MISSOURI?

A. No, Mr. Frame has not examined the market power implications of the proposed merger under the assumption that full-scale wholesale competition is introduced in generation markets in Missouri and the surrounding region.

Q. IN YOUR OPINION, IS THERE AN INCREASED RISK THAT AMEREN COULD EXERCISE MARKET POWER UNDER FULL-SCALE WHOLESALE COMPETITION?

A. Yes, in my opinion, there is an increased risk that Ameren could exercise market power under full-scale wholesale competition. Under current wholesale regulation, FERC regulates wholesale generation prices on the basis of embedded costs. Furthermore, if wholesale generation suppliers want to sell their generation at market-based prices, they must file a request with FERC and prove that they will not be able to exercise market power in the existing wholesale market. In Order No. 888, FERC addresses its application of its "general dominance standard" for new and existing generation capacity in its review of market-based rate applications by wholesale sellers. This valuable "checkpoint" currently helps to protect wholesale and retail consumers from the exercise of market power by wholesale suppliers.

If FERC were to deregulate the wholesale generation market entirely, the process whereby FERC approves a utility's request for market-based rates would be eliminated. If this checkpoint were removed, I fear that market power abuse among wholesale suppliers, including Ameren, if the proposed merger is approved, could increase.

Q. EVEN IF THE ENTIRE WHOLESALE GENERATION MARKET IS NOT DEREGULATED, ISN'T THERE AN INCREASED RISK THAT AMEREN COULD

EXERCISE MARKET POWER IN DEREGULATED WHOLESALE SPOT-MARKETS?

A. Yes, even if the entire wholesale generation market is not deregulated, there is an increased risk that Ameren could exercise market power in deregulated wholesale spot-markets. Most ISO proposals that are currently being considered include the establishment of a spot-market, where excess energy would be sold on a short-term basis. Even if the prices of wholesale generation sales made under contract remain regulated by FERC, the spot-market price in any given hour would be determined by the market clearing price of a market in which suppliers place bids that may or may not reflect their true costs of production. In fact, there is qualitative and quantitative evidence that bids would be significantly above suppliers' true costs of production.[13] If the Midwest ISO proposal includes the establishment of a spot-market, there is a possibility that Ameren would have the ability to exercise market power in that deregulated wholesale market.

Q. HAS UE ASSESSED WHETHER OR NOT THE MERGER WOULD CREATE THE POTENTIAL FOR AMEREN TO EXERCISE MARKET POWER UNDER THE ASSUMPTION THAT RETAIL COMPETITION IS INTRODUCED IN MISSOURI?

A. No, Mr. Frame has not examined the market power implications of the proposed merger under the assumption that retail competition is introduced in Missouri. As noted above, Mr. Frame's reason for not considering how the ownership of all of the generating units of UE and CIPS by a single, unregulated generation company might affect the potential for market power abuse by the merged companies is that he does not know how retail competition would be designed and implemented in the State. He states that "absent a relatively complete description of how most [retail competition] issues will be handled, I do not believe that it is either feasible or desirable to seek to address the market power implications of the proposed UE-CIPS merger." (Direct Testimony of Rodney Frame, November 1, 1996, page 19).

[13] Please refer to Tellus Institute's paper entitled "Leveraging -- The Key to the Exercise of Market Power in A Poolco." November 1996.

Q. DO YOU AGREE WITH MR. FRAME'S JUSTIFICATION FOR NOT CONSIDERING A RETAIL COMPETITION SCENARIO IN HIS MARKET POWER ANALYSIS?

A. No, as noted above, I do not agree with Mr. Frame's justification for not analyzing the market power implications of this proposed merger under any retail competition scenario. It appears to me that Mr. Frame is trying to downplay the potential market power implications of the proposed UE-CIPS merger under retail competition, despite the fact that retail competition is a strong possibility in both Missouri and Illinois at some point in the future. In particular, Mr. Frame should have analyzed the ability of Ameren to exercise *horizontal* market power under retail competition. UE has the burden of proof to demonstrate that the proposed merger is not detrimental to the public interest. By failing to examine the market power implications of the proposed merger under the assumption that retail competition is introduced in Missouri (as well as under the assumption that the wholesale generation market is deregulated), UE has disregarded the Commission's specific request for such an examination.

Q. WHAT EVIDENCE IS THERE THAT RETAIL COMPETITION IS A STRONG POSSIBILITY IN BOTH MISSOURI AND ILLINOIS?

A. There are a number of pieces of evidence that indicate that retail competition is a strong possibility in both Missouri and Illinois. First, on July 12, 1996, parties in this Case unanimously agreed to a stipulation whereby UE will file a 100 megawatt retail wheeling pilot program by March 1, 1997, for customers in its Missouri service territory if the proposed UE-CIPS merger is approved. In Illinois, Central Illinois Light Company (CILCO) implemented a retail wheeling pilot program in April, 1996, containing 2,349 residential customers. This program has since been revised such that the number of participants has doubled. In addition, various retail competition bills are being negotiated by stakeholders in Illinois for consideration by the Legislature.

Second, the significant number of retail competition investigations in the region and nationally, as well as orders and proposals to begin retail competition as early as 1998 (i.e., in the states of California, New Hampshire, Massachusetts, New York and New Jersey), provides an indication that retail competition will likely be further investigated in Missouri and Illinois.

Third, Mr. Ryan Kind, Chief Economist of the Office of Public Counsel, and Mr. Morris Brubaker, of Brubaker & Associates, have both stated that retail competition is likely to be introduced to some degree in Missouri over the next five to ten years (Transcript, September 5, 1996, pages 76 and 79).

Fourth, in response to an OPC DR regarding UE's appraisal of the likelihood of retail competition in Missouri, UE stated that it "has adopted a must assume approach to the direct retail competition issue." This suggests that UE believes that retail competition is a very strong possibility.

Finally, the conventional wisdom of many utility analysts is that mergers are a good way to prepare for full-scale wholesale and retail competition. The fact that UE and CIPS are proposing to merge could, therefore, be interpreted as evidence that the Applicants believe that retail competition is forthcoming.

Q. ARE THERE OTHER REASONS WHY THE MARKET POWER ANALYSIS OF THE PROPOSED UE-CIPS MERGER SHOULD BE PERFORMED ASSUMING VARIOUS RETAIL COMPETITION SCENARIOS?

A. Yes. The market power implications of the proposed UE-CIPS merger under various retail competition scenarios are important because these implications could constrain the *process* by which the Missouri PSC would be able to implement retail competition and/or the specific *market structure* that the PSC would be able to implement. It is crucial that the market power that the merged companies could potentially exercise under different retail competition scenarios be carefully and thoroughly considered so that efforts can be made to preempt significant market power abuse in a future, retail competitive environment.

Furthermore, the vertical and horizontal market power that could be exercised by Ameren's *aggregator* function after the merger under retail competition should also be assessed. In the September issue of CIPSCENE, Jim Backman, the CIPS Marketing Vice President made the following comment:

> "And now, of course, with the merger, we're looking at transitioning our marketing efforts and marketing strengths to mesh together with Union Electric's marketing strengths, and the opportunities there are absolutely unlimited from a marketing perspective. That's where we can start doubling and tripling the impacts

that we originally thought of within our marketing action plan by carrying them over to Missouri and bringing their programs over to Illinois ... and that's what I'm talking about when I talk about meshing."

Various approaches to mitigating market power in the aggregator sector are discussed in Section VII of my testimony.

VII. MITIGATING MARKET POWER

Q. GIVEN YOUR FINDING THAT IT APPEARS THAT THE PROPOSED MERGER WILL NOT INCREASE THE APPLICANTS' ABILITY TO EXERCISE MARKET POWER AT THE WHOLESALE OR RETAIL LEVELS *UNDER THE STATE'S CURRENT REGULATORY FRAMEWORK*, WHY ARE YOU DISCUSSING MEASURES TO MITIGATE MARKET POWER?

A. As I discussed in Section III of my testimony, the Missouri PSC should carefully and thoroughly analyze whether the ability of the merged utilities to exercise market power under various wholesale and retail competition scenarios is likely to be greater than the ability of each individual utility to exercise market power under various wholesale and retail competition scenarios. In order to facilitate the Commission's analysis, it should require the Applicants, which bear the burden of proof, to carefully and thoroughly analyze whether the ability of the merged utilities to exercise market power under a deregulated wholesale market scenario and under retail competition scenarios is likely to be greater than the ability of each individual utility to exercise market power under r deregulated wholesale market scenarios and under various retail competition scenarios. If the Commission's evaluation indicates that under certain deregulated wholesale and retail competition scenarios, there is likely to be significant market power due to the merged companies, then the PSC should identify and implement appropriate measures to mitigate the market power *prior* to deregulating generation and commencing retail competition. Therefore, the Missouri PSC should be informed about the measures that could be used to mitigate market power under wholesale and retail competition, as the Commission itself requested in its September 25, 1996 Order.

Mitigating Vertical Market Power In Generation - Open-Access Tariffs, ISOs, Transmission Expansion

Q. HOW HAS FERC ADDRESSED VERTICAL MARKET POWER ISSUES IN ORDER NO. 888?

A. FERC's open access transmission Order No. 888 (Final Rule in Dockets No. RM 95-8-000 and RM 94-7-001) is intended to deal with potential vertical market power abuse resulting from the price deregulation of the wholesale generation market by opening up wholesale power sales to competition, whereby public utilities owning, controlling, or operating transmission lines are required to file non-discriminatory, pro forma *open-access tariffs* that offer non-affiliated electricity suppliers the same transmission service they provide to themselves.

FERC's Order also applies the core requirement of transmission access and pricing to power pools and coordination arrangements between and among utilities. Furthermore, power pools are required to restructure their ongoing operations and open up membership to non-utility members by the end of 1996 as part of what is required to mitigate vertical market power.

Another measure that FERC identified in its Order No. 888 that could help mitigate potential vertical market power is the establishment of a regional *independent system operator* (ISO) that would manage and control the transmission lines in the particular region. FERC provides guidelines for establishing an ISO, including the principles that an ISO: 1) have no financial interest in the economic performance of any market power participant; 2) should have control over the operation of interconnected transmission facilities within its region; 3) should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules; and 4) should make transmission system information publicly available to all suppliers on a timely basis. In effect, utilities would have to agree to turn their transmission assets over to the operational control of an ISO, thus helping mitigate the potential for vertical market power abuse.

A third measure that FERC identified in its Order No. 888 that could help mitigate potential vertical market power is the *expansion of transfer capability*, or the "expansion obligation" provision. According to this provision, a public utility would be *required* to enlarge its transmission capacity if necessary to provide transmission services to customers seeking them. FERC believes that this provision is necessary to mitigate a utility's vertical market power that could be exercised by restricting capacity. However, FERC recognizes that a utility may not be able to enlarge transmission capacity if it can not obtain the

necessary approvals or property rights under applicable federal, state, and local laws. If a utility fails after making and documenting *a good faith effort* to obtain the necessary approvals or property rights, it can request to be relieved of its expansion obligation by an appropriate filing at FERC.

Q. AS PART OF THE PROPOSED UE-CIPS MERGER, WILL THE APPLICANTS FILE OPEN-ACCESS TRANSMISSION TARIFFS?

A. Yes, according to testimony given by Maureen Borkowski before the Missouri PSC, "UE and CIPS will file wholesale open-access transmission tariffs for the combined system with FERC coincident with the Merger approval application, offering service comparable to that used by UE and CIPS. Specifically, UE and CIPS will offer both Point-to-Point service and Network service in a manner consistent with [FERC's] Pro Forma tariffs." (Exhibit No.18, Direct Testimony of Maureen Borkowski, page 14).

Q. WILL FERC'S OPEN-ACCESS AND COMPARABLE PRICING PROVISIONS SUFFICIENTLY MITIGATE VERTICAL MARKET POWER?

A. The extent to which FERC's open-access and comparable pricing provisions will help mitigate vertical market power abuses will depend upon a number of factors, including those identified by economist John Wilson:

- The extent that regulators can control all the subtleties of system design, operation and interconnection that can greatly affect the relative success of rival generators (including the transmission owner's own generation).

- The extent that FERC can adequately control the strategic power that large, (merged) utilities might have in dealing with potential competitors.

- The extent that such factors as transmission constraints and "pancaking" of rates in the relevant geographic region will inhibit the development of competitive markets. (J. Wilson, "Merger Policy Guidelines for the Electric Power Industry," *The Electricity Journal*, January/February 1996).

Dr. Mark Frankena, who previously served as deputy director for antitrust in the Bureau of Economics of the FTC, believes that FERC's open-access and comparable pricing provisions will *not* sufficiently mitigate vertical market power. He states that:

> Given the inevitably limited information and manpower available to regulators, it is unrealistic to expect that such regulations, including Orders 888 and 889, will make the ownership, control and operation of transmission systems irrelevant to competition in the sale of delivered bulk power.
>
> A utility may limit the availability of transmission service to competitors in numerous ways. It may decide to change (or not change) the output levels of its generators, to leave a low-voltage line connected, or to limit supplies of reactive power in order to constrain the amount of transmission capacity available to competitors. It may also delay expanding or repairing transmission facilities, prolong maintenance outages or schedule maintenance outages during critical periods. In addition, it may engage in power sales that create loop flows that foreclose transmission service in another corridor." (Frankena, Mark. "FERC Must Fix Its Electric Utility Merger Policy." *The Electricity Journal*. Volume 9, Number 8: pages 38 and 39).

In short, the success of FERC's Order No. 888 has yet to be demonstrated, and should not be *assumed* to be successful until such time that it can be demonstrated.

Q. DOES FERC APPEAR TO BELIEVE THAT ITS OPEN-ACCESS AND COMPARABLE PRICING REQUIREMENT WILL *ELIMINATE* POTENTIAL VERTICAL MARKET POWER ABUSE?

A. No. FERC seems to recognize that even with non-discriminatory open-access transmission tariffs in place, transmission constraints may still affect the bounds of relevant markets within which a seller's potential exercise of market power would need to be analyzed. Further, as discussed above, there is the possibility that the combination of such physical transmission constraints, pricing constraints, and strategically located generation facilities owned by a seller may result in market power in load pockets.

Q. ARE UTILITIES, INCLUDING UE AND CIPS, CONSIDERING ESTABLISHING ISOS?

A. Yes, many utilities including UE and CIPS are considering establishing ISOs. Eight ISOs are currently being planned: in the MAAC region, New York, New England, California, Texas, the Pacific Northwest, Wisconsin, and the Midwest.[14] Some utilities have already

[14] Falcone, Charles. "Efficient Transmission Pricing for an ISO." *The Electricity Journal*. Volume 9, Number 9: page 88.

made filings at FERC to establish ISOs. In other regions, utilities are at various stages in discussions about the establishment of regional ISOs. UE and CIPS, for example, are "participating in the review and the potential development of the Midwest ISO." (Transcript, September 5, 1996, page 88). Twenty-one companies are involved in this review. At this point, it is unclear whether UE and CIPS will actually participate in the Midwest system, if and when such an ISO is established.

Q. HAVE THE ISO PROPOSALS THAT HAVE BEEN FILED AT FERC MET FERC'S GUIDELINES?

A. In general, it is my understanding that the ISO proposals that have been filed at FERC have been inadequate relative to FERC's guidelines. For example, on November 13, 1996 FERC rejected the PJM proposal for an ISO. For this reason, eighteen commissioners from ten states (including two commissioners from the Missouri PSC) recently signed the "Declaration of Independence - Why Transmission and System Operation Must Be Truly Independent from the Ownership of Generation." In this statement, the commissioners assert that:

> "most ISO proposals put forth to date have been seriously deficient in one or both of two key areas: (1) the scope of functions entrusted to the ISO is too limited, so it does not effectively control transmission pricing and system operation, and (2) the ISO is not truly independent."

John Howe, Chair of the Massachusetts DPU, stated that if the concept of ISOs as an alternative to more far-reaching steps to prevent the exercise of market power is to be taken seriously, "then it is essential that ISOs have sufficient independence and authority to do the job that a truly competitive electricity market will expect." (*NARUC Bulletin*, No. 44-1996, page 2).

Q. WHAT OTHER MEASURES COULD HELP MITIGATE VERTICAL MARKET POWER?

A. The functional unbundling of a utility's services, including the separation of its generation, transmission, and distribution into distinct business units (e.g., subsidiaries) owning

different types of assets, and with separate operation and management, could also help mitigate vertical market power problems.

Vertical market power could be mitigated, and possibly completely eliminated, if utilities are required to, or voluntarily, divest enough of their generation assets to a sufficient number of independent companies. For example, the California Public Utilities Commission has required Pacific Gas & Electric and Southern California Edison to sell 50 percent of their fossil-fired generation.[15] As another example, in a settlement agreement filed October 1, 1996 with the Massachusetts Department of Public Utilities, New England Electric System agreed to sell all of its generating assets (more than 4,600 MW) in return for full recovery of stranded costs.[16]

Mitigating Horizontal Market Power In Generation

Q. DOES FERC ALSO ADDRESS HORIZONTAL MARKET POWER IN ITS ORDER NO. 888?

A. Yes. In Order No. 888, FERC addresses whether, in its review of market-based rate applications by wholesale sellers, it should apply a "general dominance standard" for new and existing generation capacity. It concluded that for new (unbuilt) capacity, it will not require a generation dominance standard because FERC has found no evidence that new capacity will create market power in the long term. The exceptions to this are 1) if evidence regarding an applicant's generation dominance with respect to its new capacity is submitted to FERC, the applicant will be required to provide a satisfactory rebuttal, and/or 2) if the applicant has existing generation, the sales from which are authorized to be made on a market basis, FERC will consider whether the new generation (when added to the existing generation with market-based authority) results in the applicant having generation dominance. This exception does not apply, however, if the sales from the applicant's existing generation are subject to cost-of-service regulation. (FERC Order No. 888, pg 66).

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[15] The California PUC has asked FERC for a series of joint technical workshops in order to design methods for mitigating and monitoring market power.

[16] "NEES Agrees to Sell Generating Assets in Return for Stranded-Cost Recovery," *Electric Utility Week*, October 7, 1996: pages 1 and 8-9.

For existing generation, FERC concluded that while it expects its Order to facilitate the development of competitive bulk power markets, it finds that there is not enough evidence on the record to make a generic determination about whether short-term market power may exist for generation sales from existing generation units. FERC has concerns about how to define the relevant markets and believes that a more rigorous analysis is needed than can be achieved with the limited market data that is generally available. It will continue its case-by-case approach to allowing market-based rates based on a specific analysis of generation market power in the relevant region.

Q. WOULD THE DIVESTITURE OF GENERATION ASSETS FROM ALL OTHER UTILITY ASSETS MITIGATE HORIZONTAL MARKET POWER?

A. Divestiture of all of a utility's generation assets to a *single* independent generating company would not mitigate horizontal market power because the pattern of generation ownership would not change. In other words, the same generating resource mix would still be controlled by one company. The only way to mitigate horizontal market power in relevant generation markets is to require that vertically integrated utilities divest their generation units into enough *separate* generation companies such that each one has a very limited market power in relevant markets.

As I recommended in Section III of my testimony, the Missouri PSC should require that, *prior* to the implementation of retail competition, UE and Ameren will fully cooperate with the PSC in both assessing their potential ability to exercise market power, especially horizontal market power, under retail competition, and in implementing all effective mitigation measures, including divestiture of generation assets. If the PSC adopts this recommendation, then Ameren will face the possibility that it will be required to relinquish ownership of some or all of its generation prior to the start of retail competition. Even if the PSC does not adopt my recommendation, UE or Ameren, if the merger is approved, could still face this possibility in the future.

Mitigating Vertical and Horizontal Market Power In Aggregation

Q. WHICH MEASURES WOULD HELP MITIGATE VERTICAL AND HORIZONTAL MARKET POWER IN AGGREGATION?

A. Three measures would help mitigate vertical and horizontal market power in aggregation, if retail competition were implemented. First, each distribution company should be required to provide *all* aggregators with non-discriminatory access to customer billing and end-use data. This data could be provided on a regulated, cost-of-service basis so that the distribution company would be appropriately compensated for providing this information. Secondly, the aggregator function of each vertically integrated utility should be spun-off into a subsidiary, and the transactions that occur between this subsidiary and the other branches of the company should be conducted at arms length and in keeping with state and federal affiliate transaction rules. Finally, the affiliate aggregator of a once-vertically integrated utility should not be allowed to use the name of said utility. Such name recognition should be eliminated so that the affiliate aggregator competes on a more level playing field with new market entrants.

VIII. CONCLUSION

Q. PLEASE OUTLINE WHAT WOULD BE AN "ADEQUATE" MARKET POWER ANALYSIS FOR THE PROPOSED UE-CIPS MERGER.

A. The market power analysis for the proposed UE-CIPS merger should:

- Recognize the unique characteristics of electricity markets, and at least all of the sub-markets I identify in my testimony.

- Appropriately define the relevant geographic markets, taking into consideration transmission constraints, especially extreme constraints that lead to load pockets, and other barriers to entry into the generation market that I identify in my testimony. This must include transmission constraints that might arise if all generation in Missouri were deregulated, and retail competition were allowed.

- Account for potential future changes in the electric industry structure, including likely medium- and long-term structural changes in generation markets, namely full-scale wholesale competition and implementation of retail competition, where the merged companies' generation assets would be divested and price deregulated.

- Not be based on the conventional HHI market concentration test, because this index is totally inadequate for the purpose of analyzing market power in the electric industry. New, more sophisticated, indices to measure market power and new methodologies to study market power in the electric industry must be developed.

Q. IN YOUR OPINION, WHAT IS THE BEST WAY TO STUDY AND QUANTIFY THE POTENTIAL FOR MARKET POWER ABUSE IN THE ELECTRICITY GENERATING INDUSTRY?

A. In my opinion, the best way to study and quantify the potential for market power abuse in the electricity generating industry is to pursue a two-fold approach, consisting of i) theoretical and empirical characterizations of the market; and ii) simulations of the particular electricity market under consideration.

The first approach might include the development of more sophisticated measures of market power, based upon sound theoretical and empirical judgment. For example, the addition of "cross-terms" and independent coefficients to an "HHI-style" index might provide some new theoretical insights into the potential for market power abuse in a deregulated electricity industry. The second approach might include some simulation

analyses of the particular electric system (i.e., the utilities in the proposed Midwest ISO) using real data, which provide results for various gaming scenarios and bidding strategies that could be adopted by owners of generation. Of course, ultimately, these two approaches would have to be made consistent and reconciled to each other.

Q. PLEASE SUMMARIZE HOW THE MISSOURI PSC SHOULD MEASURE THE POTENTIAL FOR MARKET POWER IN A MEANINGFUL WAY.

A. A rigorous, meaningful analysis of the potential for the increased exercise of market power after a merger in the electric utility industry can *not* be adequately performed by analyzing only the pre- and post-merger values of the HHI, even if the electricity market is appropriately segmented into sub-markets. The UE-CIPS merger analysis must, at the very least, include some scenario-based simulations of the actual electric system that directly analyze the potential for Ameren to influence the price of electricity. In addition, one should develop a more sophisticated index of market power.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Education

Ph.D.	Physics, Columbia University, 1974
M.A.	Physics, Columbia University, 1969
B.S.	Physics and Philosophy, M.I.T., 1966

Experience

1993-present	Director of Energy Group, Tellus Institute.
1991-present	Director of Planning, Tellus Institute.
1977-present	Energy Group. Responsibility for a broad range of research on integrated resource planning energy conservation; electric generation planning issues; and modelling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning.
1978-1980	Consultant to Brookhaven National Laboratory.
1979	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976-1978	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974-1976	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.
1973	Instructor, Putney - Antioch Graduate School.

Testimony

Agency	Case or Docket No.	Date	Topic
Federal Energy Regulatory Commission	EC96-10-000 (Tellus 96-050F)	Sept. 1996	Review of the joint application of Baltimore Gas & Electric Company and Potomac Electric Power Company for approval of their proposed merger and organization
Maryland Public Service Commission	8725 (Tellus 96-050)	July 1996	Review of the joint application of BGE and PEPCO for approval of their proposed merger and reorganization
Illinois Commerce Commission	95-0551 (Tellus 95-302)	March 1996	Review of joint application of Central Illinois PSC, CIPSCO Incorporated, and Union Electric Company for approval of their proposed merger and reorganization
Vermont Public Service Board	5724 (Tellus 94-064)	July 1994	Review of Central Vermont Public Service's planning for its power supply resources over the past 5 years and its management of its resource portfolio
Illinois Commerce Commission	94-0065 (Tellus 94-112A)	June 1994	Assessment of the extent to which Byron 2, Braidwood 1 and Braidwood 2 nuclear units may be considered used and useful for ratemaking purposes by Commonwealth Edison, and recommendation of an appropriate ratemaking treatment of the units based on this assessment
		July 1994	Rebuttal Testimony in above docket
Kansas Corporation Commission	180,056-U	February 1994	Oral Testimony (no written testimony) on establishment of IRP rules for electric and

			gas utilities
Public Utilities Commission of Hawaii	7257 (Tellus 93-144A3)	December 1993	Critique of HECO IRP plan. Recommendations re: better and simpler approach to taking environmental externalities into account in integrated resource planning
Arkansas Public Service Commission	93-132-U (Tellus 93-148)	November 1993	Review application of Arkansas Electric Cooperative Corporation (AECC) for a certificate of public convenience and necessity for the construction, ownership, operation, and maintenance of a hydro-electric generating facility at Dam No. 2 ("H.S. #2") on the Arkansas River
		January 1994	Sur-Rebuttal Testimony in above docket
Public Utilities Commission of Georgia	4152-U (Tellus 93-100)	August 1993	Review of ratemaking aspects of the Clean Air Act Compliance plans of Georgia Power Company and Savannah Electric and Power Company
Pennsylvania Public Utility Commission	A-110300 F. 051 (Tellus 92-026)	July 1993	Critique of certain aspects of the Joint Applicants' filing with respect to whether the Joint Applicants have satisfied the requirements of the Pennsylvania PUC's siting regulation
Public Utilities Commission of Ohio	91-635-EL-FOR 92-312-EL-FOR 92-1172-EL-FOR (Tellus 92-165)	April 1993	Comments and recommendations re: Cincinnati Gas & Electric Company's integrated resource plan submitted in the Company's 1992 Electric Long Term Forecast Report
Georgia Public Service Commission	4133-U, 4136-U (Tellus 92-078)	October 1992	Review of the need for new capacity on the Georgia Power Company, Savannah Electric & Power Company, and Southern Company system over the next three years, 1992-1995

Public Utilities Commission of Ohio	92-708-EL-FOR 92-1123-EL-FOR (Tellus 92-041A)	September 1992	Comment on Centerior Energy Corporation's integrated resource plan and Clean Air Act compliance plan submitted in the Company's Long Term Forecast Report; specific recommendations for action on behalf of the Company to improve components of its resource and Clean Air Act compliance planning process
Public Service Commission of the State of Georgia	4131-U, 4136-U (Tellus 91-266)	June 1992	Adequacy of the 1992 Integrated Resource Plans of Georgia Power Company (GPC) and Savannah Electric Power Company (SEPCO)
U.S. Bankruptcy Court - Manchester, NH	BK-91-11336 Chapter 11	March 1992	Adequacy of bankruptcy plan filed by New Hampshire Electric Cooperative, Inc.
Public Utilities Commission of Ohio	91-410-EL-AIR (Tellus 91-082)	December 1991	Ratemaking treatment of Cincinnati Gas & Electric Company's 39.63% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Public Utilities Commission of Ohio	92-418-EL-AIR (Tellus 91-091)	December 1991	Ratemaking treatment of Columbus Southern Power Company's 24.20% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Maine Public Utilities Commission	89-193, 89-194, 89-195 (ESRG 89-189B & 90-039)	August 1990	Review of Bangor Hydro-Electric Company's solicitation of bids with a request for proposals dated July 24, 1989, and its approach to the evaluation of the respondents' bids.
New Hampshire Public Utilities Commission	DF 89-085 (ESRG 90-051)	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation: Issues Affecting NH Consumers
		September 1990	Supplemental Testimony in above docket.
Florida Public Service Commission	891345-EI (ESRG 90-017)	April 1990	Rate base treatment of Gulf Power Company's 63-MW ownership share of the Scherer 3 generating unit.

Michigan Public Service Commission	U-9458 (ESRG 89-158)	February 1990	Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan.
Vermont Public Service Board	5330 (ESRG 89-078)	December 1989	Presentation of results of ESRG Study: *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.*
	Further Testimony in above Docket	February 1990	
		February 1990	Surrebuttal Testimony in above Docket
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-90A)	October 1989	Recommendations regarding the proper ratemaking treatment for PECo's Limerick 2 nuclear unit.
Florida Public Service Commission	881167-EI (ESRG 89-034)	May 1989	Ratebase Treatment of Gulf Power Scherer 3 Capacity
Federal Energy Regulatory Commission	ER88-630-000 (ESRG 88-153)	April 1989	Pass Through of Performance Incentive Program Charges by New England Power Company
Public Service Commission of the District of Columbia	Formal Case No. 877 (ESRG 88-Proposed by PEPCO 128D)	February 1989	Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site
	(ESRG 88-128E) Rebuttal Testimony	March 1989	
Michigan Public Service Commission	U-8871 (ESRG 88-32)	April 1988	Review of the Appropriate Avoided Costs for the CPCo System
	(ESRG 88-32A)	August 1988	Rebuttal Testimony

Maine Public Commission	87-268 (ESRG 30A)	April 1988	Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power Utilities
	87-268 (ESRG 87-30A1)	August 1988	Supplemental Testimony
Pennsylvania Public Utility Commission	M-870111, G-870087 G-870088 (ESRG 88-01)	February 1988	Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs
Pennsylvania Public Utility Commission	R-870732 (ESRG 87-80)	November 1987	Investigation into Pennsylvania Power Company's Share of Perry 1 Nuclear Unit and Assessment of Physical Excess Capacity. Direct and Rebuttal Testimony.
Michigan Public Service Commission	U-7830 (ESRG 85-35E)	December 1987	Review of the Application of Consumers Power Company to Recover Its Midland Investment
Pennsylvania Public Utility Commission	R-870651 (ESRG 87-50D)	October 1987	Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System.
Federal Energy Regulatory Commission	ER-86-694-001	September 1987	Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission
Maine Public Utilities Commission	86-85	June 1987	Investigation of Reasonableness of Rates
		August 1987	Surrebuttal
Maryland Public Service Commission	7972	February 1987	Investigation by the Commission of the Justness and Reasonableness of the Rates of

			Potomac Electric Power Company
Arizona Corporation Commission	U-1345-85-367 (Tellus 86-42B)	February 1987	Concerning the Prudence of Palo Verde Investment
Michigan Public Service Commission	U-8578	January 1987	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8585	January 1987	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Pennsylvania Public Utility Commission	R-860378 (Tellus 85-083A)	September 1986	Economics of Duquesne Light Company's Share of Perry 1
		November 1986	Surrebuttal
Pennsylvania Public Utility Commission	R-850267 (Tellus 85-083B)	September 1986	Economics of Penn Power's Share of Perry 1
		November 1986	Surrebuttal
		March 1987	Supplemental
Michigan Public Service Commission	U-8348	July 1986	Palisades Performance Standards
Michigan Public Service Commission	U-8291	April 1986	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8286	February 1986	Power Supply Cost Recovery Plan for Consumers Power
Michigan Public Service Commission	U-8297	January 1986	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Michigan Public Service Commission	U-8285	January 1986	Power Supply Cost Recovery Plan for Indiana & Michigan Company
Division of Public Utilities, Dept. of	85-2011-01 85-999-08	January 1986	Construction of a Transmission Line and Transmission Facilities in Southwestern

Business Regulation			Utah
New York Public Service Commission	28252	October 1985	Shoreham - Rate Moderation
		January 1986	Surrebuttal
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224 (Tellus 83-080)	June 1985	Wolf Creek Excess Capacity and the Prudency of Company Planning
Federal Energy Regulatory Commission	ER-84-560-000 (Tellus 85-019)	April 1985	Callaway Excess Capacity and a Review of Union Electric Planning
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U 142-100-U	April 1985	General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas
Michigan Public Service Commission	U-8042	February 1985	Power Supply Cost Recovery Plan for Consumers Power Company
Michigan Public Service Commission	U-8020	January 1985	Power Supply Cost Recovery Plan for Detroit Edison Company
Massachusetts Department of Public Utilities	84-49, 84-50, 84-140, 627, 1656 & 1957	January 1985	Economics of Completing Seabrook 1 for Four Massachusetts Utilities
Michigan Public Service Commission	U-7830(M)	December 1984	Future Capacity Requirements of Consumers Power Company
New Hampshire Public Utilities Commission	84-200	November 1984	Investigation of Public Service Company of New Hampshire Financing Plan to Complete Construction of Seabrook 1
Michigan Public Service Commission	7830	October 1984	In the Matter of the Application of Consumers Power Company for Authority to Increase its Rates Applicable to the Sale of Electricity

Maine Public Utilities Commission	84-113	September 1984	Investigation of Seabrook Involvement by Maine Utilities
Missouri Public Service Commission	ER-84-168	August 1984	In the Matter of Union Electric Company of St. Louis, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company
Michigan Public Service Commission	U-7785	April 1984	In the Matter of the Application of Consumers Power Company for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for Calendar Year 1984
Ohio Power Siting Board	02-00022	February 1984	In the Matter of the Cleveland Electric Illuminating Company/Ohio Edison Company Amended Application to Construct and Operate a Transmission Facility Identified as the Perry-Hanna 345 kV Transmission Line
Michigan Public Service Commission	U-7775	February 1984	In the Matter of the Application of Detroit Edison Company to Implement a Power Supply Recovery Plan in its 1984 Electrical Rates
Maine Public Utilities Commission	81-276	July 1983	As to the Avoided Costs for Cogeneration and Small Power Production Facilities on the Maine Public Service Company System
South Carolina Public Service Commission	82-352-E	June 1983	Review of A.S. Beck Analyses Regarding the Economics of the Catawba Nuclear Station
North Carolina Utilities Commission	E-2, Sub 461	June 1983	Application by Carolina Power and Light Company for Increase in Electric Rates
Michigan Public Service Commission	U-7550	May 1983	Application of Detroit Edison Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates

Michigan Public Service Commission	U-7512	April 1983	*Application of Consumers Power* Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates
Pennsylvania Public Utilities Commission	R-822169	March 1983	Excess Capacity for Pennsylvania Power & Light Company
North Carolina Utilities Commission	E-100, Sub 47	February 1983	Power Plant Performance Standards and and Fuel Adjustment Clauses
Federal Energy Regulatory Commission	ER82-481 1982	December Options	Overview of Conservation and Generation
Kentucky Public Service Commission	83-14	December 1982	Review of the Kentucky-American Water Company Capacity Expansion Program
Maine Public Utilities Commission	81-276	December 1982	As to the Avoided Costs for Cogeneration and Small Power Producers
Maine Public Utilities Commission	81-114	November 1982	Maine Public Service Company Investigation of Power Supply Planning and Purchases
Maine Public Utilities Commission	82-174	October 1982	Capital Costs of the Seabrook Nuclear Units
Indiana Public Service Commission	36818	October 1982	An Economic Assessment of the Marble Hill Nuclear Station
New Hampshire Public Utilities Commission	DE81-312	October 1982	Investigation Into Supply and Demand of Electricity for Public Service Company of New Hampshire
Michigan Public Service Commission	U-6923	May 1982	Consumers Power Company Electricity Case
Alabama Public Service Commission	18337	January 1982	Long-Range Capacity Expansion Analysis
State of New York Energy Planning Board	SEMP II Hearings	November 1981	Conservation and Generation Planning
Pennsylvania Public Utility Commission	80100341	September 1981	Operating and Capital Costs: Limerick Nuclear Station; Surrebuttal

Maine Public Utilities Commission	MPUC 80-189	April 1981	Electric Energy Costs: Seabrook Nuclear Power Plants; Surrebuttal
Pennsylvania Public Utility Commission	I-80100341	February 1981	Operating and Capital Costs: Limerick Nuclear Generating Station
Ohio Public Utilities Commission	80-141 EL-AIR	December 1980	CAPCO Construction Program; Generation Planning
Michigan Public Service Commission	U-6360	September 1980	Generation Expansion Planning: Consumers Power Company
Pennsylvania Public Utility Commission	I-79070315	August 1980	CAPCO Construction Schedule; Surrebuttal
Connecticut Power Facility Evaluation Council	F-80	June 1980	Renewable Resource Electric Generation in Connecticut
Pennsylvania Public Utility Commission	I-79070317	March 1980	CAPCO: Generation Planning and Reliability
Michigan Public Service Commission	U-5979	June 1979	Forecast Critique and Adjustments: Consumers Power Company
Massachusetts Dept. of Public Utilities	19494	August 1978	Long-range Electric Demand Forecast: Boston Edison Company
Pennsylvania Public Utility Commission	438	March 1978	Long-range Forecast of Electric Energy and Demand (Philadelphia Electric Company)

Tellus Research

January 1996 *Achieving Efficiency and Equity in Nevada's Electric Industry - Comments Submitted by the Attorney General's Office of Advocate for Customers of Public Utilities on Issues Posed by the State Assembly in A.C.R. #49 Directing a Study of Competition in the Generation, Sale, and Transmission of Electricity.* Tellus Study No. 95-153A1. Co-author.

December 1995 *Promoting Environmental Quality in a Restructured Electric Industry.* A Report to: The National Association of Regulatory Utility Commissioners. Tellus Study No. 95-056. Co-author.

October 1995 — *Power Pools and Least-Cost Compliance with the Clean Air Act.* A Report to: the Pew Charitable Trusts. Tellus Study No. 94-113. Principal investigator.

September 1995 — *Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities.* Tellus Study No. 93-251. Principal investigator.

September 1995 — Discussion Paper: An Overview of the Generic Issues Related to the Amendment to Illinois Senate Bill 1058. Submitted to the Illinois Consumer Utility Board. Tellus Study No. 95-210.

September 1995 — Tellus' Initial Comments on CEEP's Discussion and Conclusions of its Electric Competition Investigation (PA PUC Docket No. I-940032). Submitted to: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-012. Co-author.

May 1995-Present — *Analysis of Economics of the Sherman Biomass Generating Unit.* Prepared for: Wheelabrator Environmental Systems, Inc. Tellus Study No. 95-154. Co-author.

March 1995 — *Order on Application for Reconsideration, Formal Case No. 813, Order No. 10590.* Public Service Commission of the District of Columbia. Tellus No. 94-051.

January 1995 — *Order on Application for Reconsideration, Formal Case No. 813, Order No. 10554.* Public Service Commission of the District of Columbia. Tellus No. 94-051.

January 1995 — In the Matter of a Notice of Inquiry to Consider Section III of the Energy Policy Act of 1992 - Integrated Resource Planning and Energy Efficiency Investments in Power Generation and Supply for Electric Utilities. Docket No. 94-342-U. Prepared for: Arkansas Public Service Commission. Tellus No. 92-153A4. Co-author.

October 1994 — *Competition and the Tennessee Valley Authority.* White paper prepared for TVA's Board of Directors. Tellus Study No. 94-096. Co-author. Draft.

May 1994-December 1995 — Independent Advisors to the Tennessee Valley Authority's Board of Directors during the Utility's Development of its First Integrated Resource Plan. Tellus Study No. 94-096. Project Manager.

December 1994 — *Report on Notice of Advanced Rulemaking Relating to Commission Review of Siting and Construction of Electric Transmission Lines.* Submitted to: Pennsylvania Office of Consumer Advocate. Docket No. L-00940091. Tellus Study No. 94-223. Co-author.

November 1994 — "Comments in Response to Edison Electric Institute's Petition for Statement of Policy on the Ratemaking Treatment of the Costs Associated with SO_2 Emissions Allowances." Docket No. PL95-1-000. Federal Energy Regulatory Commission. Tellus Study No. 94-113. Co-author.

September 1994 *Electric Transmission Pricing.* A report to: American Wind Energy Association. Tellus Study No. 94-39. Co-author.

April 1994 *Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings.* Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300. Co-author.

December 1993 *Aligning Rate Design Policies with Integrated Resource Planning.* A report to: National Association of Regulatory Utilities Commissioners. Tellus Study No. 92-047. Co-author.

August 1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 35: Adoption of the Guidelines for Integrated Resource Planning by Electric Cooperatives. Tellus Study No. 93-053. Co-author.

August 1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 39: PURPA Standards as Amended by the Energy Policy Act of 1992. Tellus Study No. 93-054. Co-author.

July 1993 *IRP Concepts and Approaches.* Report to Hydro-Quebec and the Public Interest Groups and Associations. Tellus Study No. 92-155. Project Manager.

June 1993 *Proposed Rules Governing Integrated Resource Planning for Electric and Natural Gas Utilities Regulated by the State of Kansas.* In collaboration with Kansas Corporation Commission Staff. Tellus Study No. 92-105. Project Manager.

May 1993 *Preliminary Study on Integrated Resource Planning for the Consumers' Gas Company Ltd.* Prepared for Consumers Gas Company, Ltd. Tellus No. 91-001. Project Co-manager. Not publicly available.

January 1992 *Sales Forecasts and Price Changes for New Hampshire Electric Cooperative.* Prepared for: Members Committee of New Hampshire Electric Cooperative. Tellus Project No. 91-173. Principal investigator.

September 1991 *America's Energy Choices: Investing in a Strong Economy and a Clean Environment.* In collaboration with the Union of Concerned Scientists, the American Council for an Energy Efficient Economy, the Natural Resources Defense Council, and the Alliance to Save Energy. Tellus Study No. 90-067. Co-author.

September 1990 *Environmental Impacts of Long Island's Energy Choices: The Environmental Benefits of Demand-Side Management.* Tellus No. 90-028A. Co-author.

July 1990 *Assessment of the Eastern Utilities Associates' Plan to Acquire UNITIL Corporation: Issues Affecting New Hampshire Consumers.* Exhibit 2 to Tellus No. 90-051. Project manager.

April 1990 — *Comments on Pacific Power and Utah Power Resource and Market Planning Program.* On behalf of Committee of Consumer Services, Utah Department of Commerce. ESRG No. 90-050A. Author.

March 1990 — *The Northeast Utilities Plan for Public Service Company of New Hampshire: Issues Affecting New Hampshire Consumers.* A report to: State of New Hampshire, Office of the Consumer Advocate. ESRG No. 90-019. Reviewer.

December 1989 *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.* A Report to the Vermont Public Service Board. ESRG No. 89-078. Principal investigator.

July 1989 — *Rhode Island's Options for Electric Generation.* A Policy Statement of the Energy Coordinating Council. ESRG No. 89-004. Co-author.

March 1989 — *Update of 1985 Study on the Economics of Closing vs. Operating Shoreham.* ESRG Report No. 89-051. Principal investigator.

July 1988 — *The Cost to Ratepayers of the Proposed LILCO Settlement.* A Report to Suffolk County. ESRG Report No. 88-23. Co-author.

April 1988 — *An Evaluation of Central Maine Power Company's Proposed Purchase of Power from Hydro Quebec.* A Report to the Maine Public Utilities Commission Staff. ESRG Report No. 87-30. Principal Investigator.

June 1987 — *NEPOOL and New England's Electricity Future: Issues and Directions.* A Report to the New Hampshire Consumer Advocate. ESRG Study No. 86-83. Co-author.

May 1986 — *Midland Options Study - A Response.* A report to the Michigan Department of the Attorney General. ESRG Study No. 85-35. Principal Investigator.

September 1984 — *The Economics of Seabrook 1 from the Perspective of the Three Maine Co-Owners.* ESRG Study No. 84-38. Principal Investigator.

May 1984 — *Power Planning in Kentucky: Assessing Issues and Choices. Project Summary Report to the Public Service Commission.* ESRG Study No. 83-51. Project manager.

April 1984 — *Power Planning in Kentucky: Assessing Issues and Choices. Generation and Transmission System Planning.* ESRG Study No. 83-51/TR II. Project manager. Principal investigator.

April 1984 — *Power Planning in Kentucky: Assessing Issues and Choices. Utility Financial Forecasts: Two Case Studies.* ESRG Study No. 83-51/TR IV. Project manager.

April 1984 — *Draft Report: Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.* ESRG Study No. 83-81. Principal investigator.

January 1984 — *Electric Rate Consequences of Retiring the Robinson 2 Nuclear Power Plant.* ESRG Study No. 83-10.

January 1984 — *Power Planning in Kentucky: Assessing Issues and Choices. Conservation as a Planning Option.* ESRG Study No. 83-51/TR III. Project manager.

December 1983 *Power Planning in Kentucky: Assessing Issues and Choices. Long Range Forecasts for Kentucky and its Six Major Utilities.* ESRG Study No. 83-51/TR I. Project manager.

July 1983 — *Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings.* ESRG Study No. 83-14/S. Co-author.

October 1982 — *The Economics of Closing the Indian Point Nuclear Power Plants.* ESRG Study No. 82-40. Principal investigator.

October 1982 — Final Report of the Kentucky Public Service Commission. ESRG Study No. 82-45. Co-author.

August 1982 — *Nuclear Capacity Factors: The Effects of Aging and Salt Water Cooling.* A Report on Research in Progress. ESRG Study No. 82-81. Co-author.

August 1982 — *The Impacts of Early Retirement of Nuclear Power Plants: The Case of Maine Yankee.* ESRG Study No. 82-91. Co-author.

April 1982 — *A Power Supply and Financial Analysis of the Seabrook Nuclear Station as a Generation Option for the Maine Public Service Company.* ESRG Study No. 81-61. Principal investigator.

January 1982 — *Guidelines for Designing Rates for Sales to Qualifying Facilities Under Section 210 of the Public Utilities Regulatory Policies Act.* ESRG Study No. 81-32. Co-author.

July 1981 — *Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern System.* ESRG Study No. 80-63. Co-author.

June 1981 — *An Analysis of the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill.* A Report to: Robert M. Herzog, Director, New York City Energy Office and Allen G. Schwartz, Corporation Counsel for the City of New York. ESRG Study No. 81-21. Co-author.

October 1980 *The ESRG Electrical Systems Generation Model: Incorporating Social Costs in Generation Planning.* ESRG Study No. 80-12. A Report to the U.S. Department of Energy. Co-author.

September 1980 *Reducing New England's Oil Dependence Through Conservation and Alternative Energy.* ESRG Study No. 79-29. A Report to the U.S. General Accounting Office. Co-author.

July 1980 *Preliminary Economic and Need Analysis of the Proposed Brumley Gap Pumped Storage Facility for the AEP System.* ESRG Study No. 80-08/P. Principal investigator.

July 1980 *The Potential Impact of Conservation and Alternative Supply Sources on Connecticut's Electric Energy Balance.* ESRG Study No. 80-09. A Report to the Connecticut Power Facility Evaluation Council. Co-author.

November 1979 *South Carolina Electric Demand Curtailment Planning.* A Report to the South Carolina Office of Energy Resources. Principal investigator.

May 1979 *Demand Curtailment Planning: Methodology.* ESRG Study No. 78-18. Chapter submitted to Brookhaven National Laboratory and the Department of Energy for the Electric Demand Curtailment Planning Study. Principal investigator.

May 1979 *Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model.* ESRG Study No. 79-06. A Report to the New England Conference of Public Utility Commissioners. Co-principal investigator.

October 1978 *The Employment Creation Potential of Energy Conservation and Solar Technologies: The Implications of the Long Island Jobs Study for New England, 1978-1993.* ESRG Study No. 78-16. Co-author.

November 1977 *Profile of Targets for the Energy Advisory Service to Industry.* ESRG Study No. 77-09. A Report to the New York State Energy Office. Co-Author.

October 1977 *The Effect on Air and Water Emissions of Energy Conservation in Industry.* ESRG Study No. 77-04. Co-author.

July 1977 *The Effects on Air and Water Emissions of Energy Conservation in Industry.* ESRG Study No. 77-04. Co-author.

June 1977 *Toward an Energy Plan for New York.* ESRG Study No. 77-03. A Report to the Legislative Commission on Energy Systems. Co-author.

April 1977 *Assessing Demand, Alternative Operating Strategies, and Utility Economics in the Service Territory of Orange and Rockland Utilities.* ESRG Report No. 77-01. Co-author.

Other Publications

1992 "Bill Indexing," chapter in: *Regulatory Incentives for Demand Side Management*, edited by S. Nadel, et al. Published by ACEEE/NYSERDA. With David Moskovitz.

March 1978 *The Use of the Pulp and Paper Industry Process Model for R&D Decision Making.* Brookhaven National Laboratory Report No. BNL 24134. Co-author.

1976 "A Non-Linear Model for the Linewidth, Intensity, and Coherence of Astrophysical Masers," *Astrophysical Journal* vol. 190.

Papers and Presentations

June 1996 "Leveraging" - The Key to the Exercise of Market Power in a Poolco. NARUC and NASUCA Summer Meetings. Co-author.

September 1995 "The Status of Regulatory Policy Affecting the Restructuring of the Electric Utilities Industry." Presentation to: Wheelabrator Technologies, Inc.

August 1995 Presentation to Maine Public Service Company on Behalf of Wheelabrator Sherman to explain Tellus' Calculation of Estimates of Total Avoided Costs for Wheelabrator Sherman Power through 2015. Co-author.

November 1994 "Nine Fallacies in Computing Avoided Costs." Distributed at: The Annual NARUC/NASUCA Conference, Reno, NV. Co-author.

September 1994 "Apples and Oranges: Using Multi-Attribute Analysis in a Collaborative Process to Address Value Conflicts in Electric Facility Siting." Presented at: Ninth National Association of Regulatory Utility Commissioners (NARUC) Biennial Regulatory Information Conference, Columbus, Ohio, September 8. Co-author.

1993 "How Should Electric Utilities Allocate Their Free EPA-Granted Allowances Among Retail and Wholesale Customers? An Unresolved Issue of Clean Air Act Compliance. Prepared for distribution at: The NARUC/NASUCA 1993 Annual Meetings, New York, NY. November 14. Co-author.

February 1993 "Integrated Resource Planning and Clean Air Act Compliance: Elements of Consistency." Prepared for Distribution at: The NARUC Energy Conservation Committee 1993 Winter Meeting, Washington, DC. Co-author.

February 1991 "The Clean Air Act Amendments of 1990 and Utility Least Cost Planning: Issues for State Regulators," for distribution at the NARUC Conservation Committee, 1991 Winter Meeting, Washington, D.C. Co-author.

February 1991	"Sustainable Development and the Future of Electric Utilities," for the Energy Conservation Coalition Electric Utility Industry Vision Paper Project, Washington, DC.
September 1989	"Six Fallacies in Computing Avoided Costs," delivered at the NARUC Least Cost Planning Conference, Charleston, S.C.
October 1988	"Ratemaking and Conservation: The Tune Should Fit the Dance," distributed at the NARUC Committee on Energy Conservation Meeting, San Francisco. October 30.
September 1987	"Electric Utility System Reliability and Reserves" (ESRG Paper). Co-author.
September 1986	"Risk Sharing and the `Used and Useful' Criterion in Utility Ratemaking" (ESRG Paper). Co-author.
September 1986	"Risk Sharing, Excess Capacity, and the "Used and Useful" Criterion." Presented to the Fifth Biennial Regulatory Information Conference sponsored by the National Regulatory Research Institute in Columbus, Ohio.
July 24-28 1978	"Energy Use Modelling of the Iron and Steel Industry," Summer Computer Simulation Conference.
Nov. 12 1977	"Energy Conservation in Industry," Northeastern Political Science Association meeting, Mt. Pocono, Pennsylvania.

Related Professional Activities

Elected to Three-Year Term as a member of the Research Advisory Committee of The National Regulatory Research Institute, October 1, 1988 - September 30, 1991. Term extended through June 1992.

Invited Speaker

June 1996 "Independent System Operators," NASUCA meeting, Chicago, IL.

November 1995 "Preserving Environmental Quality Under Electric Restructuring," NARUC Energy Conservation Committee meeting, New Orleans, LA.

November 1994 "Electricity Transmission Pricing," presented at NARUC Committee on Energy Conservation, Annual Meeting, Reno, NV. Co-author.

September 1994 Sixth Natural Gas Industry Forum, Quebec City. September 25-28.

June 1993 The National Energy Summit, in conjunction with the Multi-Media Energy Education Project of the Jefferson Energy Foundation - "Balancing Energy-Environment-Economy (E^3)", Washington, DC. Panelist.

September 1992 "Natural Gas Planning: An IRP Case Study." Presented at: The NARUC Conference on Integrated Resource Planning, Burlington, Vermont, September 13-16, 1992. Co-author.

September 1992 Fourth Natural Gas Industry Forum, Montreal.

March 1992 American Gas Association Long Range Forecasting for Integrated Resource Planning Seminar - "How Externalities and Supply Costs Affect IRP".

December 1991 Edison Electric Institute -- Strategic Planning Committee - "Incorporating Environmental Externalities into Integrated Resource Planning".

November 1990 NARUC Energy Conservation Committee Meeting, Orlando, Florida - "Rate Impacts of Demand-Side Management Programs".

November 1990 NARUC and NASUCA Joint Annual Meeting, Orlando, Florida - "Environmental Externalities and Integrated Resource Planning".

Awards and Honors

1968-1974	Faculty Fellowship, Physics Department Columbia University.
1966-1970	New York State Regents Fellowship.
1967-1968	Adam Leroy Jones Fellow in Philosophy, Columbia University.

9/96