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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

REBUTTAL TESTIMONY

FILED[3]

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Missouri Public
Service Commission

OF

MICHAEL S. PROCTOR

UNION ELECTRIC COMPANY
d/b/a AMERENUE

CASE NO. E0-2001-684

Jefferson City, Missouri
September 2001

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REBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

UNION ELECTRIC COMPANY

d/b/a AmerenUE

EO-2001-684

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael S. Proctor. My business address is 200 Madison St., P.O. Box 360, Jefferson City, Mo. 65102-0360.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Missouri Public Service Commission (Commission) as Manager of Economic Analysis in the Energy Department.

Q. WHAT IS YOUR EDUCATION BACKGROUND AND WORK EXPERICENCE?

A. I have Bachelors and Masters of Arts Degrees in Economics from the University of Missouri at Columbia, and a Ph.D. degree in Economics from Texas A&M University. My previous work experience has been as an Assistant Professor of Economics at Purdue University and at the University of Missouri at Columbia. Since June 1, 1977 I have been on the Staff of the Commission and have presented testimony on various issues related to weather normalized energy usage and rate design for both electric and natural gas utilities. With respect to electric issues, I have worked in the areas of load forecasting, resource planning and transmission pricing. In 1997 and 1998, I served as the Staff Vice Chair of the Market Structure and Market Power working group of the Commission's Task Force on Retail Competition. Since December of 2000, I have served as chairman of the Forward Congestion Markets Subgroup of the Southwest Power Pool's (SPP's) Congestion Management Systems Working Group.

Q. WHAT ARE YOUR CURRENT DUTIES IN THE ENERGY DEPARTMENT AS MANAGER OF ECONOMIC ANALYSIS?

A. I supervise the Economic Analysis group within the Energy Department. This group is responsible for various issues related to weather normalization of sales and rate design. In addition to my supervisor's role, I have focused my attention on the development and structure of Regional Transmission Organizations (RTOs) for the purpose of increasing efficiency and reliability in the competitive supply of electricity. Because of the restructuring of the electric industry toward the increased competitive supply of electricity, I have also focused on the issue of market power within the electric industry.

Q. IN THIS INSTANT CASE, WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will address the issue of whether AmerenUE leaving the Midwest ISO (MISO) and joining the RTO proposed by the Alliance companies (Alliance) is detrimental to the public interest. Since AmerenUE is requesting to leave MISO and join the Alliance RTO (ARTO), being "detrimental to the public interest" becomes a question of whether AmerenUE's membership in MISO or ARTO is more beneficial to the public interest. If AmerenUE's joined the least beneficial RTO, this would constitute a decrease in public benefits and therefore would be detrimental to the public interest. (I will refer to the group of transmission companies as the "Alliance" and to the RTO proposed by those transmission companies as the "ARTO.")

Q. HOW DOES YOUR REBUTTAL TESTIMONY RELATE TO THE DIRECT TESTIMONY OF AMERENUE WITNESS MR. DAVID A. WHITELY?

A. Mr. Whitely's direct testimony is in two parts. In the first part, Mr. Whitely addresses the history of AmerenUE's involvement with regional transmission, the reasons that it initially joined the MISO and the reasons that it filed with the Federal Energy Regulatory Commission (FERC) for permission to withdraw from the MISO to join the ARTO. The reasons given by Mr. Whitely are: 1) the continued viability of the MISO was extremely uncertain; 2) significant transmission service revenue shifts away from AmerenUE would result if it remained in the MISO; 3) operational concerns in Illinois if Illinois Power Company and Commonwealth Edison Company both left the MISO; 4) the Alliance approach to revenue allocation among transmission owners is better; and 5) the Alliance business model is better. [page 6, Whitely Direct]

In the second part of his direct testimony, Mr. Whitely describes the Settlement Agreement that resulted from FERC initiated settlement negotiations on the combined applications of Illinois Power, Commonwealth Edison and Ameren to leave the MISO and join the Alliance. Finally, Mr. Whitely lists what he believes to be the benefits of the Settlement Agreement: 1) creates the largest seamless electric energy market in the eastern interconnect; 2) provides AmerenUE with non-pancaked transmission rates within this market; 3) adopts the revenue distribution protocol of the Alliance, which means higher transmission revenue credits for AmerenUE's retail customers; 4) integrates reliability in the Midwest through joint coordination of operations and planning between the MISO and Alliance through the Inter-RTO Cooperation Agreement (IRCA), which is Attachment A to the Settlement Agreement; and 5) assures an independent market monitor for MISO and Alliance. [pages 12-13, Whitely Direct]

Q. WHAT IS THE SIGNIFIGANCE OF THE TWO PARTS OF MR. WHITELY'S DIRECT TESTIMONY?

A. The first part of Mr. Whitely's direct testimony deals with what he sees as the disadvantages of MISO compared to the Alliance as a public interest issue. Thus, the benefits listed on page 6 of Mr. Whitely's direct testimony are at the crux of this issue of comparing the public benefits of MISO to Alliance. The primary difference between MISO and Alliance is found in their basic model of business structure.

My rebuttal testimony will present arguments that the implementation of the not-for-profit business model of the MISO has been superior to that of the for-profit business model of the ARTO. While discussion of models of business structure can be somewhat theoretical, my testimony will also address the experience of stakeholders in the ARTO development process as practical evidence of the implementation problems that have occurred with the Alliance. In this respect, my conclusion is that the transmission owners forming the Alliance have used the for-profit structure of the ARTO as a means to maintain control of design of the ARTO to advantage their profitability both in the short and long run.

The second part of Mr. Whitely's direct testimony deals with the public interest benefits from the Settlement Agreement between MISO and Alliance. In order for these claimed benefits to be relevant to this proceeding, it must be argued that those benefits would not occur if AmerenUE's request to leave MISO and join the Alliance is denied.

At page 11 of his direct testimony, Mr. Whitely states: 1) "AmerenUE's withdrawal from the Midwest ISO is a non-severable part of the package deal;" and 2) "Failure of the Commission to approve AmerenUE's withdrawal from the Midwest ISO would destroy the settlement reached by all parties, unquestionably delay the start-up of both RTOs, and cast uncertainty on the future of RTOs in the Midwest."

Since the Inter-RTO Cooperative Agreement was in large part worked out and agreed to by MISO and ARTO prior to the Settlement Agreement reached by MISO and Alliance, the heart of the Settlement Agreement is the elimination of pancaked rates between MISO and Alliance, and any discussion of benefits from that agreement should focus on this question. My rebuttal testimony is that the rate methodology adopted by the Settlement Agreement does not really eliminate pancaked transmission rates, rather it accumulates the revenues from multiple pancaked rates and places them into a larger single rate; i.e., instead of a stack of individual short pancakes based on how many control areas through which a transaction is scheduled, there is a single tall pancake that applies to everyone. Although a pancaked rate enhances AmerenUE's transmission revenue position, pancaked transmission rates can negatively impact generation market efficiency and have an overall detrimental effect on the public interest.

Q. IS THE QUESTION OF WHETHER OR NOT IT IS IN THE PUBLIC INTEREST FOR AMEREN TO JOIN AN RTO AN ISSUE IN THIS CASE?

A. According to Mr. Whitely's direct testimony, Ameren does not view this to be at issue in this case for several reasons. First, Ameren was ordered by the Commission to join an Independent System Operator (ISO) as a condition for approval of the merger of

Union Electric Company and Central Illinois Public Service Company Inc. (CIPSCO). Second, with retail competition in Illinois, Ameren is required to join an RTO.

With respect to this question of the public interest regarding RTOs, I have attached as Schedule 1 to my rebuttal testimony a paper, which discusses the relevance of RTOs to the situation in Missouri where we do not have retail competition for electricity, but we do have wholesale competition for electricity.

Q. WHAT IS A BRIEF SUMMARY OF THIS PAPER?

A. The purpose of regional transmission is to enhance the competitiveness of wholesale markets for electricity. The role of the RTO is to facilitate markets for electricity, similar to the role of stock exchanges, such as the New York Mercantile Exchange. If RTOs perform well as market facilitators, wholesale competition for electricity will be enhanced and this will benefit Missouri consumers of electricity as well as the utilities that serve these consumers.

There is a warning. Wholesale competition has and will continue to result in a significant increase in price risk for those who lean on the market to purchase electricity. The major role for the Commission relative to dealing with wholesale competition will be on issues related to how well utilities manage this risk. In this regard, it should be noted that, unlike retail competition in electricity, wholesale competition in electricity was not a determination made by states but instead was made at the federal level.

I. MISO VS. ALLIANCE

Q. WHAT IS THE FUNDAMENTAL DIFFERENCE BETWEEN THE MISO AND ALLIANCE BUSINESS MODELS FOR PROVIDING REGIONAL TRANSMISSION SERVICE?

A. The MISO business model is that of a not-for-profit entity that will manage the transmission assets of its member Transmission Owners. In essence, being not-for-profit means that the MISO will not own transmission assets. It should be pointed out that in the Southeast, Southern Company is proposing a for-profit ISO that will not own transmission assets. Because this is not at issue here, I will not make this distinction between being for-profit and owning transmission assets, except where such a distinction is appropriate to indicate what the differences might be.

On the other hand, the Alliance proposes what has been called either a Transco (transmission company) or an ITC (independent transmission company) model in which ARTO would own transmission assets and earn a profit on those assets. In this testimony, I will use the term Transco to mean a transmission owning entity that has been declared "independent" by the FERC.

Q. DOES THE MISO BUSINESS MODEL ALLOW FOR TRANSCOS?

A. Yes, it does allow for members of the MISO to be Transcos. The MISO worked out a general agreement by which any Transco approved as "independent" by the FERC could be a member of the MISO with certain expanded functions beyond what an integrated utility would have as a non-independent, transmission-owning member of MISO. In essence, the MISO will act as an umbrella RTO organization for smaller Transco entities. The MISO RTO umbrella functions would be to provide: 1) security coordination (i.e., determine whether requested use of the transmission system meets reliability/security constraints) and one stop shopping over a large geographic area, 2) insure that congestion management systems (i.e., determine how scarce transmission is allocated among competing requests for use) across all members work together to integrate markets for electricity over a large geographic area, and 3) coordinate transmission planning with respect to maintenance and facility expansion over a large geographic area. Transcos would maintain control of their transmission systems, but would be subject to the overall authority of the MISO as the security coordinator.

At this time there are two Transcos that are negotiating with MISO to become members under the general agreement: **American Transmission Company** (primarily eastern Wisconsin formed from 7 investor-owned utilities, 12 municipal utilities, 4 electric cooperatives and 2 public power entities); and **TRANSlink** (Alliant Energy - primarily in Minnesota, MidAmerican Energy – primarily in Iowa, Nebraska Public Power District, Omaha Public Power District, Corn Belt and Xcel Energy – primarily in New Mexico and Colorado). In addition, on August 31, DTE Energy's transmission subsidiary, International Transmission Company (ITC), announced that it plans to file with the FERC to join the MISO and withdraw its participation with the Alliance. ITC intends to join the MISO as an independent Transco. Schedule 2, attached to my testimony is a copy of the press release issued by DTE Energy.

Q. WHAT THEN IS THE RATIONALE FOR HAVING THE RTO OWN AND OPERATE TRANSMISSION ASSETS FOR PROFIT?

A. Those favoring a for-profit RTO argue that it will have greater incentives to provide transmission services desired by transmission customers and to minimize the costs of providing those services. For example, former Commissioner and Chairman of the FERC, Curt L. Hebert Jr. states:

> *For now, FERC must re-evaluate the traditional cost-of-service formula of depreciated original cost. We should institute incentive rates with proper review of customer satisfaction and oversight. ... Among the alternatives that are available to accomplish these goals, I believe that, while there*

may be circumstances that require ISOs or other entities, from an economic perspective the most cost-effective and efficient alternative for transmission operation is a Transco, a company promoting efficiency through market solutions. ... Through performance-based regulation, FERC can provide incentives for maximum efficiency of operations rather than embedded, cost-based regulation under FERC transmission pricing policy. [**The Electricity Journal**, March 1999, pp. 21-22]

I disagree with this and will argue that in the case of Alliance, the primary rationale for setting up its proposed RTO as a Transco is to keep control of RTO formation in the hands of the transmission owning entities.

Q. WHY DO YOU DISAGREE THAT A FOR-PROFIT RTO WILL HAVE GREATER INCENTIVES TO PROVIDE TRANSMISSION SERVICES DESIRED BY TRANSMISSION CUSTOMERS?

A. RTOs by their very nature are monopolies, being the only provider of transmission service within their specified service region. The rates they charge and services they offer will be regulated by the FERC. If they fall short of recovering the necessary revenues, they will request rate increases. In a competitive environment, falling short on sales causes an entity seeking market share to seek out better services to offer to customers. Economists call this "product differentiation." But simply owning assets on which a profit is earned does not give a regulated monopolist the incentive to differentiate its product or to offer innovative products. FERC Commissioner William L. Massey stated his views on the issue of having to be a for-profit RTO to have incentives to meet customer needs as follows:

Another claim is the for-profit transcos will focus on serving the needs of their customers, and that not-for-profit entities such as ISOs will not. This flies in the face of the positive track record of the hundreds of public power agencies and rural electric co-ops. Ask the customers of Basin Electric Cooperative, Oglethorpe, Salt Rive Project, Santee Cooper, or New York Power Authority whether these transmission entities would *operate more efficiently with a profit motive. A profit motive is a fine thing, but it is not the sole guarantee that customers' needs will be met.* [**The Electricity Journal**, March 1999, p.19]

Q. HOW SHOULD RTOS BE STRUCTURED IN ORDER TO BEST MEET THE PRODUCT NEEDS OF TRANSMISSION CUSTOMERS?

A. With a monopoly provider of service, the alternative to a lack of competition is to give stakeholders input to what products will be offered. In the language of RTOs, stakeholders need to be given a voice in how the markets for transmission are to be structured. The Alliance has done exactly the opposite. Stakeholders were not given a voice in the formation of the market structure and transmission products, and instead, the Alliance set up its own group of experts to determine the basic market design for the ARTO. Only after the Settlement Agreement between MISO and Alliance was reached in early April of 2001, did the Alliance begin to hold stakeholder meetings. Because decisions needed to be made immediately to meet the December 15, 2001 date for the ARTO to begin operations, these meetings were designed only to inform stakeholders of the decisions that the Alliance had already made. Stakeholders were allowed to comment on these decisions, but there were no established processes by which stakeholder inputs would be taken into account in altering the decisions already made by the Alliance. This was not, and still is not, a collaborative process.

Q. WHY DO YOU DISAGREE THAT A FOR-PROFIT RTO WILL HAVE GREATER INCENTIVES TO MINIMIZE ITS COST OF PROVIDING TRANSMISSION SERVICES?

A. As stated previously, RTOs are regulated monopolists. One of the long-time issues with the regulatory model is that allowing a fair rate of return on investment to a regulated monopolist does not provide incentives for that entity to minimize its costs. Moreover, the regulatory model depends on hearings in which the level of costs is a primary issues. Costs take two forms in the regulatory model: 1) recovery of prudently-incurred/reasonable expenses; and 2) return on-and-of prudently-incurred/reasonable investments. The key words with respect to cost minimization are "prudently-incurred/ reasonable." Both the not-for-profit RTO and the for-profit RTO will face regulatory scrutiny with respect to expense and capital recovery for facilities. The difference is that the for-profit RTO will be allowed to earn an equity return on both transmission facilities it owns and on other facilities it will need to carry out its RTO functions. The return on for-profit RTO facilities will include not only debt financing but also equity financing. The not-for-profit RTO will debt finance facilities needed to carry out its RTO functions and separate transmission owners will earn a rate of return (debt and equity) on direct transmission facilities.

The argument is that the Board of Directors and management of the for-profit RTO would then be responsive to shareholders for their actions. On the other hand, the Board of Directors and management for the not-for-profit RTO are responsive to its members, both transmission owners and other stakeholders (e.g., power marketers, independent power producers, transmission dependent utilities, state regulators and various groups representing end-use customers). The inclusion of stakeholders that do no hold stock or have a vested interest in the profitability of the RTO adds to the spectrum of views about the prudence/reasonableness of expenditures made by the RTO, a view that will be expressed before expenditures are incurred. In this regard, FERC Commissioner William L. Massey also stated his view on incentives for minimizing costs.

An ISO that operates the transmission facilities of several members will be required through its charter to run the grid efficiently and economically. It will have a fiduciary duty to its members to collect rates that have been approved by FERC, and its books and records will be subject to public scrutiny. It is bunk to argue that such an entity will not have the incentive to operate efficiently. [**The Electricity Journal**, March 1999, p.19]

Q. WHAT IS THE IMPORTANCE OF HAVING TO ANSWER TO SHAREHOLDERS COMPARED TO HAVING TO ANSWER TO MEMBERS?

A. In regards to having to answer directly to shareholders, it is interesting to note that investor ratings of utilities have included a factor for "regulatory risk." In essence, the tougher regulators are regarding allowance of expenses and return on equity, the lower are the investor ratings of the utility. The corollary in competitive markets is: the tougher the competition, the lower are the returns for the competitors, and this tougher competition is an incentive for reducing costs, which results in lower prices for ultimate consumers. This same regulatory model will determine rates for both the not-for-profit and the for-profit RTO. Based on historical experience with regulated utilities that blame regulators for unfair or unreasonable cost disallowances, it is difficult to see how having to answer directly to shareholders would enhanced the incentive for RTOs to minimize its costs. A better approach is to receive input from members through stakeholder advisory groups prior to making decisions.

Q. AS INDICATED IN MR. HEBERT'S POSITION, IS WHAT HE CALLS PERFORMANCED-BASED RATEMAKING (PBR) A VIABLE ALTERNATIVE TO TRADITIONAL RATEMAKING FOR RTOS?

A. It is a viable alternative for both not-for-profit and for-profit RTOs. One approach to PBR is to set targets by comparing the RTO's performance with the industry or economy as a whole – external criteria based PBR. The RTO is allowed to keep a portion of excess earnings when, for example, costs are below the target, but incurs reduced earnings when costs are above the target. It should be noted that with external criteria used to set cost targets, the PBR must also include service level standards in order to keep the RTO from reducing costs by simply reducing its services and/or the quality of services.

It is argued that in order for this type of external criteria based PBR to be effective, "earnings" must have some value to the RTO. Clearly the value to the for-profit RTO is that some portion of excess earnings from exceeding the targets are retained by the RTO and passed on to its shareholders. In the case of the for-profit RTO that does not own the transmission assets of all of its members, some portion of excess earnings could be shared between transmission owners and the RTO. In the case of the not-for-profit RTO that does not own any transmission assets, some portion of earnings could be shared between transmission owners and the RTO through a system of rewards for RTO performance. Incentives for RTO performance can be the same in all three cases.

In addition to external criteria based PBR, there are also internal criteria based PBR that focus directly on the consumer and include such criteria as reliability, on-time performance, timely response to complaints and levels of customer satisfaction with such things as product availability. In a competitive product market, these internal criteria are developed in order for the competitors to gain market share and profitability. However, in a regulated product market, the provider is still a monopolist that will not lose market share when customers are not satisfied. Thus, internal criteria need to be developed irrespective of whether the RTO is for-profit or not-for-profit.

Q. WHAT HAS BEEN THE EXPERIENCE THUS FAR WITH MISO COMPARED TO ALLIANCE IN CUSTOMER SATISFACTION?

A. With respect to customer satisfaction, the differences between MISO and Alliance have been abundantly clear. The MISO set up a Policy Advisory Stakeholder's Group through which the positions and desires of the customers of the RTO are expressed. At this time, the focus has been on fundamental issues with respect to FERC Order No. 2000 ("Order 200"), with the primary focus being on the development of market structures for congestion management, energy imbalances (i.e., generation not matching load for a load serving entity) and ancillary services (i.e., generation services required for maintaining reliable levels of stability and voltage on the transmission system; for example, Regulation – automatic generation control to maintain acceptable frequency levels, Var Support – to maintain acceptable voltage levels and Operating Reserves – to cover generation outages).

The driving force at the MISO has been MISO's receipt of viable input from those who will be the customers of the RTO. The experience at Alliance has been the opposite. The Alliance set up its group of experts from the member utilities. These experts developed a position that is focused on benefits to transmission owners. Only after being ordered by the FERC to have a collaborative process, did the Alliance experts present their position to stakeholders for comments. This is a process that a Transco wanting to protect its revenue position would be expected to take. It is not a viable process for receiving customer input in order to increase customer satisfaction.

In addition to protecting revenues, the Alliance has focused on keeping costs to a minimum. This may sound like a good thing, but when this means not having the level of services that will be needed to effectively run a regional transmission system, it becomes a significant concern as to when there will be a process that demonstrates concern for customers.

Q. IS IT YOUR TESTIMONY THAT THE MAKING THE RTO FOR-PROFIT DOES NOT INHERENTLY PROVIDE GREATER INCENTIVES TO OFFER IMPROVED CUSTOMER SERVICES OR PROPERLY REDUCE COSTS THAN THE INCENTIVES FOR A NOT-FOR-PROFIT RTO?

A. Yes, that is my testimony. If incentives are found to be desirable for RTOs, then performance measures will need to be built into either business model. Whether the RTO is responding to shareholders (for-profit) or stakeholders (not-for-profit), criteria will need to be in place in order to evaluate RTO performance. The significant difference is in whether transmission customers are explicitly involved in specifying the criteria (not-for-profit RTO), or will the design depend on the overall goal of shareholders to provide the proper incentives (for-profit RTO).

Q. WHAT IS THE OVERALL GOAL OF THE SHAREHOLDER IN A FOR-PROFIT RTO?

A. The shareholder's goal is to maximize rate of return. In a competitive business area, this focus on rate of return is dispersed among other objectives that contribute to maximizing rate of return. For example, to increase rate of return a competitor can either increase sales (market share) and/or decrease costs. When these two objectives come into conflict (e.g., decrease costs by reducing customer service that results in a loss of sales), the firm facing competition must decide which of these two objectives will best meet its overall goal of maximizing rate of return.

Q. WHAT IS THE OVERALL GOAL OF TRANSMISSION AND IS THAT GOAL MET BY MAXIMIZING RATE OF RETURN?

A. Transmission is a *support service* having the purpose of enabling electricity (the primary product) to move from generator to end-use. The overall goal of transmission is to enable a market for electricity to function in the most efficient possible manner. With respect to a for-profit RTO, the goal of maximizing rate of return within a regulated environment does not by itself translate to efficient markets for electricity.

Q. WHAT IS MEANT BY "MOST EFFICIENT USE OF THE TRANSMISSION SYSTEM?"

A. In the short run, the most efficient use of the transmission system is one in which the lowest cost generation is used to meet load requirements subject to maintaining the security of the transmission system. In this definition, "lowest cost generation" translates to "lowest bid generation" when the generation market is perfectly competitive. In the long run, the most efficient use of the transmission system is one in which new transmission is built when the cost of new transmission is less than or equal to the gain in cost savings from generation which results from the addition of the new transmission. What the most efficient use of the transmission system does not mean is "maximizing throughput." Again, FERC Commissioner Massey clearly states his view on efficient use of the transmission system:

> *One of the camp's arguments is that only for-profit entities can achieve efficiencies because they alone will have the incentive to maximize throughput. ... Surely, Transco proponents do not mean that they will achieve more throughput by driving their systems harder and risking the violation of reliability rules. That is the only way they can squeeze more capacity out of the transmission system.* [**The Electricity Journal**, March 1999, p. 19]

Q. HOW DOES THE RTO ACHIEVE THE MOST EFFICIENT USE OF THE TRANSMISSION SYSTEM IN THE SHORT RUN?

A. The FERC has conceptualized this issue with the term "congestion management." In this respect, Order 2000 specifies that an approved RTO should have market-based congestion management. One such market-based congestion management system is for the RTO to balance bid-based supply and demand in real time subject to the constraints of the transmission system. An alternative market structure that may accomplish the same objective is to have active trading in transmission rights where the RTO only allows transactions to take place that have associated transmission rights. When more than one structure can accomplish the same objective, economists evaluate the transaction costs associated with the alternatives, and the alternative with the lowest transaction costs is the most efficient structure.

Q. DOES RATE OF RETURN MAXIMIZATION NECESSARILY LEAD THE FOR-PROFIT RTO TO THE OBJECTIVE OF STRUCTURING CONGESTION MANAGEMENT IN THE MOST EFFICIENT SHORT-TERM USE OF THE TRANSMISSION SYSTEM?

A. No, it does not. In order to understand the objectives that are consistent with rate of return maximization, a context for the regulatory process is needed. For example, the context may be one in which the transmission owner is allowed to share in profits above a certain level (e.g., PBR or regulatory lag). Within that context, the RTO monopolist would attempt to maximize rate of return by minimizing its cost and/or maximizing its revenues.

Q. DO YOU HAVE AN EXAMPLE OF HOW MAXIMIZING RATE OF RETURN COULD LEAD TO RTO BEHAVIOR THAT IS NOT CONSISTENT WITH EFFICIENT SHORT-RUN USE OF THE TRANSMISSION SYSTEM?

A. Yes. In order for the market to operate most efficiently, not only must the RTO take bids to supply electricity, but should also encourage bids from the demand-side of the market. Increased responsiveness to prices by customers (demand price elasticity) will help to mitigate price spikes when generation capacity is short and when there is congestion on the transmission system. However, this increased responsiveness to prices by customers will also decrease the quantity of transactions on the transmission system during periods where short-term supply is not restricted. Under rate designs that focus on revenue recovery from increased use of the system, decreased transactions from greater demand elasticity also means decreased revenues. In a PBR context, this lowers the rate of return to shareholders in the for-profit RTO. Thus, the for-profit RTO having an incentive to maximize its sales in order to maximize profits, would have an incentive to discourage, rather than encourage demand-side bids.

Notice also that encouraging demand-side bids will require additional software for the RTO to enable it to process information on demand-side bids. Increased software means additional costs that may hurt the RTO functioning under an external criteria based PBR scheme. Thus, the for-profit RTO may have a cost incentive to discourage, rather than encourage demand-side bids.

Q. DO YOU HAVE ANOTHER EXAMPLE OF HOW MAXIMIZING RATE OF RETURN COULD LEAD TO RTO BEHAVIOR THAT IS NOT

CONSISTENT WITH EFFICIENT SHORT-RUN USE OF THE TRANSMISSION SYSTEM?

A. Yes, I do. In attempting to maximize opportunities for the RTO to make profits, the for-profit RTO may design a market structure in which the RTO actually earns a return by taking a position in the electricity market. Most likely this would occur through what the FERC has designated as congestion management, energy imbalance or ancillary services. For example, the Alliance is proposing a congestion management system in which transmission customers are required to submit balanced schedules. What this means is that prior to real-time (typically a day ahead), each load serving entity must tell the RTO what generation resources it is planning to use to meet its load obligations. In order to do this, each load serving entity must forecast its load requirements for the next day and schedule how it wants its generation resources to be dispatched to meet its load forecast. In the Alliance's view, it will also perform a load forecast and if its load forecast is higher than the sum of what is scheduled by market participants it will anticipate a shortage of capacity. In this case, the ARTO will contract for the additional generation resources it believes are needed. If the ARTO's load forecast is too high, then it has purchased capacity that is not needed to serve load. Under a possible PBR approach, what the ARTO can collect from participants is capped and to the extent that the ARTO can cut its cost by effective capacity purchases, the ARTO is allowed to keep some portion of the "savings." With such a profit motive, the ARTO will be taking a position in the day-ahead market.

I totally disagree with any market design that has the RTO taking a position in the market. First, because of its unique monopoly status with respect to transmission, the

RTO clearly has an advantage over other suppliers of ancillary services. If the RTO is allowed to take a position in the market, this will discourage competition. Moreover, the market must have absolute confidence in the RTO and the actions taken by the RTO. If the RTO is in any way a for-profit market participant, it will have the appearance of taking actions to enhance its position in the market.

Q. FOR A NOT-FOR-PROFIT RTO, HOW WOULD THESE MARKET DESIGN ISSUES BE DETERMINED?

A. In a not-for-profit RTO, a collaborative process is followed in which stakeholders come to an agreement regarding market design issues. A collaborative process will typically take longer, but the guiding principle for coming to agreement will be enhancing market efficiency. What is at issue here is who are the decision makers and what is the basis on which they make their decisions. In Order 2000, the FERC stated clearly the decision makers (Board of Directors for the RTO) must be independent of market interest. In addition, decision makers should have the goal of enhancing efficiency in the markets for electricity. Independent Boards of Directors should and will review market designs that are submitted to the FERC. The FERC has final approval, but should find significant evidence in favor of a market design that was arrived at through an open collaborative process and approved by an independent Board of Directors.

Q. WHAT HAS BEEN THE COLLABORATIVE PROCESS EXPERIENCE WITH THE ALLIANCE REGARDING MARKET DESIGN?

A. To date, the transmission owner members of the Alliance have made all decisions regarding market design. Not until the Settlement Agreement has there been anything close to gathering input from stakeholders.

Section 3.3 of the Settlement provides for the implementation of a process for ongoing stakeholder involvement in the Alliance. Development of this process has already begun and will be completed no later than May 15, 2001.[5] *PG&E National Energy Group (PG&E) and Duke Energy North America LLC (Duke) argue that, while they support the need for early actions to secure stakeholder input into Alliance, more needs to be done. For instance, they claim that a stakeholder advisory committee with defined membership and voting requirements must be established to provide policy input to Alliance.*[6] *State Commissions urge the Commission to move without delay to implement the stakeholder process prior to formation of the Alliance.*[7] *Enron Power Marketing Inc. (Enron) argues that in the area of congestion management under the Cooperation Agreement,*[8] *there is a lack of any meaningful participation by stakeholders other than transmission owners.*[9]

In response to those comments, Trail Staff states that Alliance Companies will file their stakeholder input plan with the Commission no later than May 15, 2001 and that parties may raise their concerns at that time.[10]

<u>Discussion</u>

We will accept this provision as filed. We agree with Trial Staff that until such a plan is filed, it is premature to entertain specific concerns as to what may or may not be included in such a process. [FERC Order On Settlement in Docket Nos. ER01-123-002 <u>et</u> <u>al</u>., May 8, 2000, pp. 4-5]

Even after the FERC ordered the Alliance to set up a collaborative process, stakeholders found it necessary to make additional filings to have the FERC order the Alliance to set up a policy subcommittee that would make recommendations directly to an independent Board. Almost two months after the May 18 date set by the FERC order on the Settlement Agreement, the FERC issued its order on the ARTO filing and made the following finding:

[5] Alliance Companies note that they recently held a stakeholder meeting to begin developing this process. <u>See</u> Alliance RTO, <u>Stakeholders Post Meeting Materials</u>, March 22, 2001. This document is available on Alliance's website at http:/www.alliancerto.com.
[6] PG&E and Duke Initial Comments at 8.
[7] State Commissions' Initial Comments at 6.
[8] Those provisions of the Cooperation Agreement about which commenters raise concerns are discussed below.
[9] Enron Initial Comments at 9.
[10] Trial Staff Reply Comments at 18.

> *We are concerned that business decisions prior to implementation of an Alliance RTO are being made by Alliance Companies. Therefore, we direct alliance Companies to decide which of the alternative business plans proposed they intend to implement within 45 days of the date of this order. We further direct that from the date of this order an independent board be established to make all business decisions for the RTO.*[30] *Until final RTO approval is granted, a stakeholder advisory committee should advise the independent board.* [FERC Order On RTO Filing in Docket No Nos. RT01-99-000 et al., July 12, 2001, p. 13.]

In this RTO order, the FERC directed the Alliance to set up its independent Board immediately. After several weeks, stakeholders had to go back to the FERC for help through the FERC's Alternative Dispute Resolution (ADR) division in an attempt to get an independent Board in place that could immediately be involved in the decision making process particularly with respect to market design issues. What is at stake here is the fact that the Alliance is currently making investment decisions with respect to software needed to begin operation on December 15, 2001 (Day 1 operation) and those decisions are being made either without foresight on what the market design will be on December 15, 2002 (Day 2 operation) or based on the transmission owners' view of what the market design will be. In order for the transmission owner members of Alliance to save money in the short term, they have continually put off the commitment to having an independent board, a staff hired by that board and a meaningful stakeholder process. Now the entire market design for the Alliance is suffering from input deficit that will be costly to correct in the future.

Q. HOW DOES THE RTO ACHIEVE THE MOST EFFICIENT USE OF THE TRANSMISSION SYSTEM IN THE LONG RUN?

[30] GridFflorida LLC, et al., 94 FERC ¶ 61,363 at 62,325 (2001).

A. In order to achieve the most efficient long-run use of the transmission system, the RTO should have in place procedures that provide incentives for building transmission whenever the value to the market from the transmission exceeds the cost of building and operating the transmission facilities.

Q. DOES RATE OF RETURN MAXIMIZATION NECESSARILY LEAD THE FOR-PROFIT RTO TO THE OBJECTIVE OF PROVIDING INCENTIVES FOR EFFICIENTLY BUILDING TRANSMISSION FACILITES?

A. No, it does not. In what has become a classic in regulatory economics, Averch and Johnson [*Behavior of the Firm Under Regulatory Constraint,* **American Economic Review**, 1962, pp. 1053-1069] show that a regulated firm operating under the standard rate of return constraint will over invest in capital. This has become known as the "Averch-Johnson Effect" (A-J Effect). The application of the A-J Effect to this specific instance is that a for-profit RTO has an incentive to build transmission in excess of what is economic. The consequences of overbuilding transmission are poor price signals to generators as to where to locate and higher costs to end-use consumers.

Q. AREN'T MOST OF THE CONCERNS BEING RAISED TODAY ABOUT TOO LITTLE TRANSMISSION BEING BUILT RATHER THAN TOO MUCH?

A. Yes, that is true. However, much of this has occurred for two reasons. First, utilities are reluctant to build transmission other than what is needed to serve their native load customers. To add transmission for transactions that do not involve serving native load (i.e., "out transactions" - leaving the utility's control area; or "through transactions" - passing through the utilities control area) would be speculative with respect to cost recovery. Second, it appears that the FERC's "or" pricing policy only requires the utility to build transmission for non-native load customers when the customer is willing to pay the incremental cost of providing that transmission. Because many transmission upgrades are lumpy (i.e., cannot be made in the small increments that would correspond to discrete customer requests), few transmission customers are willing to pay the large incremental costs associated with these upgrades.

In states where retail competition has begun, it is fairly typical for state legislators to mandate price caps at current rates as a protection from increased costs to customers from implementing retail choice. However, these price caps can also prevent utilities from recovering a return on and of investments in new transmission facilities. Thus, during the transition periods (period with price caps), there are in place disincentives to expand transmission capability.

Q. ARE THE CURRENT DISINCENTIVES TO BUILD TRANSMISSION EVIDENCE THAT THE A-J EFFECT IS NOT APPLICABLE TO AN RTO THAT OWNS THE TRANSMISSION FACILITIES?

A. No, they are not. Absent other disincentives to invest in transmission that have nothing to do with the choice between not-for- profit vs. for-profit RTO structure, what is at issue here is whether the choice of the RTO business model provides an incentive for over investment in transmission. A not-for-profit RTO does not earn a rate of return on the investment in transmission and therefore does not have an incentive to over invest; while a for-profit RTO does earn a rate of return on the investment in transmission and does have an incentive to over invest.

Q. FOR A NOT-FOR-PROFIT RTO, HOW WOULD THE ISSUE OF INVESTMENT IN TRANSMISSION BE DETERMINED?

A. In a not-for-profit RTO, the RTO's planning staff would develop sets of load flow studies based on the location of generation and load within the region. The purpose of these load flow studies is to determine the flowgates within the region that will be most susceptible to congestion. While load flow studies can measure where congestion is likely to occur on the transmission system, by themselves they cannot measure the value to the market of this potential congestion. In order for transmission planning to be responsive to the market, the RTO's congestion management system will need to have in place a method for measuring how the market values congestion on the transmission system. Given the market's value of congestion, the RTO can compare that valuation to the cost of upgrading the transmission system and when the market value is higher than the cost of upgrading, the transmission system should be upgraded.

Q. WHAT METHOD ARE MOST RTOS PROPOSING FOR DETERMINING THE MARKET VALUE OF CONGESTION?

A. The New England, New York and Pennsylvania-New Jersey-Maryland (PJM) ISOs all use locational marginal pricing (LMP) as the basis for energy imbalance markets and to determine congestion prices. Both the MISO and the Southwest Power Pool (SPP) have committed to developing similar types of congestion pricing systems. Because Order 2000 requires a market-based congestion management system, the Alliance also appears to be considering a system that incorporates some form of congestion pricing. However, the approach proposed by the Alliance is to minimize the role of congestion pricing by requiring market participants to submit balanced schedules on a day-ahead basis.

Q. HOW DOES CONGESTION PRICING PROVIDE THE RTO WITH A MEASURE OF THE MARKET VALUE OF CONGESTION?

A. I will answer this question with a simplified illustration of congestion prices for a flowgate (e.g., set of transmission lines and transformers) that connects two nodes within the transmission network. In this illustration, there is generation and load at each node, but at node A, the generation is cheaper than at node B, and there is sufficient generation at node A to serve the load at both nodes. However, the capacity of the flowgate connecting node A to node B is less than the load requiring service at node B. Thus, some of the higher cost generation from node B must be used to serve the load at node B. Suppose the generation at node A costs $15/MWh and the generation at node B costs $25/MWh – these are the LMPs at each node. The congestion price between node A and node B is the savings in generation cost that would occur if the capacity of the flowgate between A and B is expanded by 1 MW. In this simple illustration, this congestion price is the difference between the LMPs at the two nodes; i.e., an increase in transfer capacity of 1 MW would allow 1 MW of $15/MWh generation at node A to be substituted for 1 MW of $25/MWh generation at node B, giving a savings of $10/MWh.

Clearly, this congestion price is for a specific hour in the year, and depending on how demand and supply conditions change throughout the year, the congestion price can also change. What the RTO must do to determine the market value of the congestion is use the generator bids at various locations over the entire year and determine what the savings would be had the transmission capacity of this flowgate been expanded. In order to do a complete transmission expansion study, the RTO needs to consider various combinations of flowgate expansions to determine which combinations result in maximizing the difference between market value and transmission cost.

Q. CAN'T THE FOR-PROFIT RTO ADOPT THE SAME MARKET-BASED METHODS FOR DETERMINING TRANSMISSION EXPANSION?

A. Yes, they could; but whether they can or not is not relevant. The relevant question is whether or not a for-profit RTO has the correct incentives to adopt these market-based methods. What the A-J Effect implies is that the for-profit RTO wanting to maximize return on investment in transmission will measure "need" for new transmission in a way that will result in maximizing the amount of transmission that gets built. As FERC Commissioner Massey points out in the ISO/Transco debate:

> *The Federal Trade Commission has argued, however, that a for-profit Transco would have the improper and inefficient incentive to favor transmission expansion solutions even when there are less costly and more efficient ways to relieve congestion. An ISO that has broad representation from all market participants may be in a better position to consider the needs of the region and to present to state regulators a more persuasive and broadly supported case for system expansions when that is the most prudent method to relieve a constraint.* [**The Electricity Journal**, March 1999, p. 19]

Q. IF THE RTO OVER BUILDS TRANSMISSION, CAN REGULATORY ACTION DISCOURAGE SUCH OVER BUILDING?

A. Yes, it appears that regulatory actions, such as disallowances for over building, could be put in place to discourage the over building of transmission. Again, that is not the point here. The point is whether or not to adopt an RTO structure that will require additional regulatory actions to be put in place.

Q. HAVE PBR DESIGNS BEEN PROPOSED TO PROVIDE INCENTIVES FOR A FOR-PROFIT RTO TO MAKE OPTIMAL TRANSMISSION INVESTMENT DECISIONS?

A. Yes, several PBR designs have been proposed to give a for-profit RTO incentives to make optimal transmission investment decisions. An excellent article on this subject was written by Steven Stoft and Frank Graves (*PBR Designs for Transcos: Toward a Comparative Framework*; **Electricity Journal**; August/September 2000; pp. 32-45). Stoff and Graves review several PBR designs for a for-profit RTO and conclude:

> *We have discovered no performance-based regulation for transcos that appears readily workable, either politically or administratively – let alone ideal. ... Perhaps the most promising approach is some dampened variation of the ideal incentive which makes the Transco responsible for upgrade costs and for all congestion and operating costs attributable to the grid. The problem with this approach is that the Transco may have to be given higher profits in order to be sure that it is not put out of business, since congestion costs can be quite large under extreme circumstances, and they are very hard to predict accurately in advance.* [pp. 44-45]

In brief, Stoft and Graves discovered that providing incentives to a monopolist is tricky business, and making that monopolist larger by conferring on it standing as an RTO simply makes the problem more difficult.

Q. CAN YOU GIVE A SPECIFIC EXAMPLE OF WHAT STOFT AND GRAVES CALL THE "IDEAL INCENTIVE," AND CONTRAST HOW THAT INCENTIVE WOULD BE APPLIED UNDER A FOR-PROFIT AND NOT-FOR-PROFIT RTO?

A. Yes, I can. The "ideal incentive" is characterized as one in which transmission is built to relieve congestion when what Stoft and Graves call the avoided "grid imperfection costs" (GIC) are greater than or equal to the "grid expansion costs."

The grid imperfection costs are the sum of congestion costs and losses, and grid expansion costs are the costs associated with building and maintaining an upgrade to the transmission system. While the expansion of the grid involves location, size and timing, the primary focus of the Stoft and Graves article was on timing.

In the case of the for-profit RTO, the PBR mechanism considered by Stoft and Graves is one in which the for-profit RTO is allowed to collect in revenues a predetermined revenue cap minus the GIC occurring on an actual basis. The problem with this approach is in attempting to determine at what level to set the revenue cap. For example, if the ultimate target is a cost-of-service level of recovery, then in order to set the revenue cap, the level of GIC must be forecasted; i.e., the revenue cap is equal to the cost-of-service target plus the forecasted (targeted) level of the GIC. In concept, the for-profit RTO would then have the incentive to invest in transmission whenever it forecasted the reduction in GIC to be greater than the return on-and-of investment in new transmission facilities. But this is like playing regulatory roulette. If the forecasted level of GIC is too low compared to actual, the earnings for the for-profit RTO are too low and it cannot attract the capital to build the transmission needed to lower the GIC costs. If the forecasted level of GIC is too high, the for-profit RTO is allowed to over earn and end-use customers do not receive any benefit from the RTO's investment in new transmission. The regulatory dilemma is where and how to set the target. Because the for-profit RTO will earn a profit by under forecasting GIC, its forecasts cannot be trusted. Thus, the forecast of GIC would become a contested issue before the FERC. Such an approach to PBR seems to have little to do with customer satisfaction.

With a not-for-profit RTO, the criteria for when to invest is the same as for the "ideal incentive." While the not-for-profit RTO can make an unbiased forecast of the GIC avoided by various transmission expansions, such forecasts are only an indicator of what the market may avoid if the new transmission is built. Instead of ordering transmission to be built, the RTO could auction the services of the new transmission to the market. Buyers would bid on the basis of what they expect to save with the addition of the new transmission and sellers would bid based on their forecasts of the construction costs and required return on-and-of investment in the new transmission. The not-for-profit RTO would not take a position in the market by building transmission facilities, but would instead act as the market facilitator.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE USE OF PBR INCENTIVES FOR RTOS?

A. It is my testimony that in order for PBR to be effective, it should use internal rather than external criteria. Internal criteria focus on what customers want, and since RTOs are regulated monopolies, external criteria that focus on earnings are not an effective means of providing the right incentives. In order to integrate internal criteria into the regulation of RTOs, the most effective approach is through stakeholder advisory groups that will provide RTOs with the services and measures that are most important to the stakeholders as customers. While this approach can be implemented in either the not-for-profit or the for-profit RTO, my major concern is that because of their primary goal, for-profit RTOs will focus on external criteria driven PBR that result in the RTO taking a position in the market, which will be detrimental to the public interest. If a Transco that is a member of a not-for-profit RTO requests PBR that would give an incentive to the Transco to take a position in the market and that Transco is not the market facilitator, then such a PBR might not be detrimental to the public interest.

II. MISO-ALLIANCE SETTLEMENT AGREEMENT

Q. WHY HAVE UTILITIES LEFT OR NOT JOINED THE MISO AND FORMED A SEPARATE ITC/TRANSCO TYPE RTO?

A. As indicated earlier, Mr. Whitely's answer to this question is AmerenUE's concern about loss of transmission revenues when pancaked transmission rates are eliminated.

Q. IS THE LOSS OF REVENUES FROM THE ELIMINATION OF PANCAKED TRANSMISSION RATES A VALID PUBLIC INTEREST CONCERN?

A. No, it is not. The loss of revenues from pancaked transmission rates is transitory in that these excess revenues would not have existed to the extent they do today had the FERC initially moved to regional transmission rates at the time of open access.

In FERC Orders No. 888 and 889 ("Orders 888 and 889"), the FERC created an incomplete system of open access to transmission, and a system that resulted in revenues being generated for transmission service that were not fundamental to the operation of competitive wholesale power markets. When FERC jurisdictional utilities filed their "pro-forma" Open Access Transmission Tariffs (OATTs), a business system of transmission was created in which each transmission provider was now able to receive revenues from sales of transmission service unbundled from the sale of electricity. In addition to filing OATTs, the utilities were required to separate the provision of transmission services from the wholesale marketing of electricity (marketing function). This led many utilities to establish transmission as separate business units that were accounted for as distinct profit centers. This means that these separate transmission units are measured internally with respect to their revenues and costs as being separate and distinct from other business units within the utility.

With this business structure firmly in place since Orders 888 and 889, transmission business within utilities that are highly interconnected to other utilities have been earning significant revenues from the sale of transmission services. As one of these highly interconnected transmission providers, AmerenUE's current level of transmission profits are threatened by regional transmission rates that remove pancaking.

Q. HOW DOES THE ALLIANCE INTEND TO DEAL WITH THIS LOSS OF REVENUES?

A. The concept envisioned by the Alliance is to determine lost revenues from a historical test year and include these lost revenues as a cost when setting transmission rates. In the Settlement Agreement, the rate component through which lost revenues are collected is called the Zonal Transition Adjustment (ZTA). The Settlement Agreement specifically states:

> 5.2(ii) "The ZTA responsibility for each zone will be calculated on the basis of lost revenues throughout the Alliance-Midwest ISO Super-Region and revenues collected from the ZTAs will be distributed between the two RTOs pursuant to the relative sources of the lost revenues, and subsequently allocated among the transmission owners within the RTOs pursuant to their respective revenue distribution methods."

This added ZTA rate component will be in place starting December 31, 2001 and will remain in place until at least December 31, 2004. In essence, the Settlement Agreement allows Ameren to continue to collect pancaked rate revenues for a "transition period" of at least three years. In addition, utilities have agreed to pay the ZTA for all of their native load, whether or not that load is otherwise under the tariff.

Q. CAN YOU ILLUSTRATE HOW THE RATES WILL BE CALCULATED UNDER THE APPROACH APPROVED IN THE SETTLEMENT AGREEMENT?

A. Yes. This illustration is highly simplified in several ways. First, I am assuming that the RTO is comprised of three transmission providers A, B and C, each with a specified transmission zone. A's zone is directly connected to B's zone, C's zone is directly connected to B's zone, but A's zone and C's zone are not directly connected. Second, in this illustration I have excluded transactions from outside the RTO. Third, each transmission provider has 1,000 kW of native load and an annual revenue requirement for transmission of $1,000. Fourth, at the outset of Orders 888 and 889 it is assumed that none of the three utilities has transmission transactions other than to serve native load customers. Therefore, the transmission rate for each of the three is the revenue requirement divided by the 1,000 kW of native load, i.e., $1,000/1,000kW = $1/kW. Subsequent to filing their OATTs, transactions occur among the three providers. For purposes of this illustration, I am assuming that 100 kW of transactions occur from each provider's zone into each of the other two providers' zones. Table 1 shows the revenues that will be collected under this set of assumptions. Table 1 also illustrates that any transaction can be classified as being into, through or out of a transmission provider's designated zone. For example, a transaction from A to A (within A) affects only A's zone and is classified as into A. A transaction from A to B affects the zones of both A and B as out of A and into B. Finally, a transaction from A to C must go through B and

Table 1: Pancaked Transmission Revenues

	Transmission Providers								
	A			B			C		
Transaction	**Into**	Through	Out	**Into**	Through	Out	**Into**	Through	Out
A→A	**$1,000**								
A→B			$100	**$100**					
A→C			$100		$100		**$100**		
B→A	**$100**					$100			
B→B				**$1,000**					
B→C						$100	**$100**		
C→A	**$100**				$100				$100
C→B				**$100**					$100
C→C							**$1,000**		
	$1,200	$0	$200	**$1,200**	$200	$200	**$1,200**	$0	$200

affects all three zones as out of A, through B and into C. Pancaked transmission rates mean that the transmission customer must pay for all affected zones. Thus, the transaction from A to C for 100 kW at $1/kW in each zone results in payments of $100 to each of the three zones. The elimination of pancaked transmission rates has been proposed by having the transmission customer only pay the transmission charge for the destination (into) zone where the load is located.

In this regard, the dollars collected from non-pancaked transmission rates is shown in the bolded "**Into**" columns for each transmission provider. Both the "Through" and "Out" columns represent revenues collected from pancaked transmission rates that the FERC allowed to be charged in Orders 888 and 889.

The Settlement Agreement proposes two components to the rate. The first component is the transmission provider's revenue requirement divided by the kW units of into service from the historical test year. In this case, each transmission provider has 1,200 kW of into service, 1000 kW from its native load and 100 kW into its zone from each of the other two zones. For purposes of this illustration, assume that the revenue requirement has stayed at $1,000. Then the "into" rate for each transmission provider would be $0.833/kW (= $1,000/1,200 kW). In a realistic example this rate would vary by transmission provider based on their individual costs and billing units. This system of individual rates for each transmission provider has been called "license plate" rates. If the revenue requirements were added together for all three transmission providers and then divided by the sum of the billing units for all three, the result would be a uniform rate for the RTO that has been called a "postage stamp" rate.

In addition to the license plate rate, the lost revenues from pancaking are added for each transmission provider. Notice that while lost revenues for A and C are $200 each, the lost revenues for B are $400. Generally speaking, transmission providers that are more highly interconnected will have larger lost revenues. To calculate the ZTA charge, divide lost revenues by the billing units for into service for each transmission provider. For A and B, the ZTA charge is $0.166/kW (= $200/1,200 kW), but for B, the ZTA charge is $0.333/kW (= $400/1,200 kW). Thus, total transmission service for A and C is $1.00/kW (= $0.833/kW + $0.166/kW) and for B is $1.166/kW (= $0.833/kW + $0.333/kW).

Q. WHAT IS THE ECONOMIC IMPACT OF COLLECTING LOST REVENUES FROM RATE PANCAKING THROUGH THE ZTA?

A. The economic impact is to set the price of transmission service at an artificially higher rate over a transition period. During that period, the transmission providers will be allowed to collect revenues in excess of their cost of service revenue requirements. First consider transmission providers A and C, who will both apply a transmission charge of $1.00/kW to native load for 1,000 kW and to strictly into transactions for 200 kW. Total revenue collection will be for $1,200, which is $200 more than its cost of service, but is also $200 less than what was earned under OATT pancaked rates. Next consider transmission provider B, who will apply a transmission charge of $1.166/kW to native load for 1,000 kW and to strictly into transactions for 200 kW. Total revenue collection will be for $1,400, which is $400 more than its cost of service, but is also $200 less than what it was earning under its OATT pancaked rates. Notice that the ZTA helps keep the highly interconnected transmission provider from having a significant loss of revenues, but also allows that provider to continue to collect above its cost of service for at least three more years.

Q. HOW WERE TRANSMISSION PROVIDERS ALLOWED TO EARN MORE THAT THEIR COST OF SERVICE UNDER OATT?

A. There are two components to over earnings, one related to native load and the other related to strictly into, through and out of transactions. First, with respect to native load, some utilities were not allowed to over earn if they experienced a rate/complaint case subsequent to having earned additional revenues from pancaked transmission rates. This assumes that in the state commissions finding of just and reasonable rates, the revenues from sales of transmission services to non-native load customers were treated as revenue offsets to the cost of transmission for the native load customers. But in the case of AmerenUE, which was on an experimental alternative regulation plan for the past six years, no such rate adjustment has explicitly been made.

Second with respect to non-native load transmission customers, utilities were not required by the FERC to annually adjust their OATT rates. There was therefore no automatic adjustment downward in rates to offset increases in sales of transmission service. Thus, Order 888 not only instituted the separate transmission business components as individual profit centers, it resulted in these profit centers being very profitable as the additional transactions by power marketers expanded sales of transmission services by the utilities.

Q. DOES THE TRANSMISSION PROVIDER ACTUALLY RECEIVE THESE OVER EARNINGS EVEN WHEN ITS NATIVE LOAD CUSTOMERS ARE NOT PUT UNDER THE RTO TARIFF?

A. Under the Settlement Agreement, even if native load customers are not put under the RTO tariff, the utility will be charged with the ZTA rate for those customers. The RTO will combine all of the revenues received from the ZTA charges and redistribute those to the transmission owners in proportion to the percentage of lost revenues for each transmission owner in the test year.

In the illustration, the way this would work is that transmission provider B, as a utility whose native load is not under the tariff would still be subject to the ZTA charge times the billing units of the native load; i.e., (\$0.333/kW)(1,000 kW) = \$333.33. This amount goes into the RTO ZTA revenue fund along with the revenues from ZTA charges collected by all the utilities. Assuming the billing units used to set rates are the same as the billing units during the first year of application of the rates, then A and C will contribute (\$0.166/kW)(1,200 kW) = \$200 each and B will contribute \$400 = (\$0.333/kW)(1,200 kW), for a total revenue fund of \$800. From Table 1, A and C have lost revenues of \$200 each and B has lost revenues of \$400 and each transmission provider is paid back what they put in. In essence, if network load pays the ZTA charge, the utility is paid back the same revenues that it paid into the fund. Thus, the over earnings by the utilities is limited to the ZTA charges for billing units of non-native load transmission customers. The reason for including the billing units of native load even when native load is not otherwise under the RTO's rate is to keep the ZTA charge down at a reasonable level. Attempting to recover lost revenues from just non-native load customers would have resulted in a significantly higher charge that looks much like a pancaked transmission rate.

Q. SHOULD THE COMMISSION BE CONCERNED WITH A POTENTIAL LOSS OF TRANSMISSION REVENUES FROM THE SETTLEMENT AGREEMENT IS VOIDED BY NOT ALLOWING AMEREN TO JOIN THE ALLIANCE?

A. No. First, the Commission should not assume that if the Settlement Agreement between the MISO and the Alliance were voided that this means the rates developed for settlement proposes would necessarily be thrown out by the MISO. Second, if the ZTA rate component were eliminated, it is true that Ameren transmission business would lose revenues, but the elimination of this pancaked rate component will increase the efficiency in the wholesale generation market and this would be a benefit to AmerenUE and its customers. Mr. Whitely's direct testimony has only given a partial view from the perspective of Ameren's transmission business and has failed to present the total picture with respect to AmerenUE and its customers. Third, at the time of the writing of this testimony, the SPP is in the process of negotiating a merger with the MISO. If this merger results, it is very likely that the Settlement Agreement between the MISO and the Alliance will need to be renegotiated. Fourth, the FERC has stated its intention to have a single RTO in the Midwest. It is not clear how the Settlement

Agreement, which resulted in two RTOs in the Midwest, meets this objective. If the SPP and MISO merge, then it is safe to assume that either a new Settlement Agreement must be reached, or the FERC will take further steps to have a single RTO in the Midwest. Moreover, in his written concurrence to the FERC's order in Docket Nos. RTO1-88-000 et al, Commissioner Massey states the following:

> *While I am very pleased with the resolve we are showing in the Northeast and the Southeast, I am disappointed that we are not applying that same resolve in all regions. To facilitate the timely development of the single Midwest RTO, which our orders today state as a clear objective, I would direct Alliance, the Midwest ISO, and the Southwest Power Pool to a mediation proceeding with the same objective and timetable as that for the Northeast and Southeast RTOs. The settlement that we approved between the Alliance and Midwest ISO was a bold step in the right direction, but those institutions should have been directed toward a single RTO from the outset. And SPP would add even greater scope to the Midwest RTO. In this order, we fail to establish a mediation proceeding for a Midwest RTO. I would have done so and in this order directed Alliance to participate along with SPP and the Midwest ISO. Although I am pleased with the progress we make today, I am somewhat disappointed that we once again miss a golden opportunity to achieve in the Midwest what we insist upon in the Southeast and the Northeast.* [Docket No. RTO1-88-000 et al, MASSEY, Commissioner, concurring, pp. 2-3]

Thus, the proper perspective of the Settlement Agreement is a transitional agreement that resolved the issue of conditions under which the three utilities would be allowed by the FERC to leave the MISO and join the Alliance. The rates developed for this settlement were developed to eliminate pancaking of rates between the MISO and the Alliance. If for some reason, this went away, there is no way that the remaining organizations could be viewed as a "single RTO" in the Midwest and it appears that the FERC would then take actions to insure a single Midwest RTO.

Q. IS MISSOURI THE ONLY STATE REGULATORY COMMISSION MAKING A DETERMINATION WITH RESPECT TO UTILITIES JOINING THE MISO VERSUS THE ALLIANCE?

A. No. The Indiana Public Utilities Commission is currently in the process of reviewing filings by all of its regulated utilities regarding this issue. This means that the ongoing viability of the Settlement Agreement between the MISO and the Alliance is not solely a matter of the determination of the Missouri Public Service Commission.

III. ALLIANCE INDEPENDENCE VS. UTILITY CONTROL

Q. WHAT HAS BEEN THE EXPERIENCE WITH ALLIANCE REGARDING THE ISSUE OF INDEPENDENCE?

A. The experience with the Alliance with respect to independence has been frustrating and discouraging. The history of the Alliance filings precedes Order 2000, starting with the Alliance filing for status as a "Transco-Lite" that would function as a regional transmission entity in which a Transco is the independent transmission operator for its own transmission and the transmission of other transmission owners. What this means is that the Alliance would provide all of the ISO functions envisioned by FERC in Orders 888 and 889, but proposed to do this as a Transco. (Since then, the term ISO has been associated with not-for-profit RTOs.) In its initial 1999 filing, the Alliance proposed a "disinterested" Board of Directors. This means Board members could not have any financial interests in the markets for electricity. However, over the past year and a half, the Alliance has failed to appoint an independent Board and has instead maintained the decision making in the hands of the transmission owners. Instead of appointing an independent Board that would begin to staff the organization, the Alliance set up what it calls a "Bridge Co" to manage the implementation phase of the Alliance. The Alliance transmission owners clearly control the finances and decisions of the Bridge Co. To date, the Alliance has not appointed an independent Board of Directors, but has only recently appointed what it calls a managing member, National Grid USA. This decision was required in the July 12, 2001 Order On RTO Filing by the FERC in which the Alliance was directed as follows:

> *We are concerned that business decisions prior to implementation of an Alliance RTO are being made by Alliance Companies. Therefore, we direct Alliance Companies to decide which of the alternative business plans proposed they intend to implement within 45 days of the date of this order.* [FERC Order On RTO Filing in Docket Nos. RT01-99-000 et al., July 12, 2001, p. 13]

On August 27, 2001, the Alliance filed a letter with the FERC stating that eight of the ten Alliance Companies had executed a Letter of Intent with National Grid USA "pursuant to which the parties have agreed to pursue the negotiation and documentation of definite agreements to enable National Grid USA, through one or more affiliates, to make an investment in, and serve as the managing member of Alliance Transco." [Alliance Companies August 27 letter to FERC, page 3]

Q. WITH NATIONAL GRID USA COMING ON AS THE MANAGING MEMBER OF THE ARTO, WILL THIS FINALLY RESULT IN AN INDEPENDENT BOARD OF DIRECTORS FOR THE ARTO?

A. No. There is an immediate problem with the Alliance's proposal to have National Grid USA take over as managing member of the ARTO. The FERC has yet to determine that National Grid USA meets the independence requirements. In fact, one of the Alliance Companies, Detroit Edison/International Transmission Company, has not executed the Letter of Intent and does not concur with the opinion of the eight other

Alliance Companies who have signed the Letter of Intent that National Grid USA meets the FERC requirement of a non-market participant. Thus, the implementation of an independent Board will be put off at least until the FERC makes a determination with respect to National Grid USA's independence.

In order to meet the requirements of the FERC's July 12, 2001 Order, the Alliance has proposed to set up an interim three-member Board of Trustees, having one member appointed by the Alliance Companies, one member appointed by the Alliance Stakeholder Advisory Committee and the third member appointed by the first two Board members. This proposal was offered by the Alliance Companies, when after repeated requests by the stakeholders to immediately set up an independent Board, the stakeholders took the issue to FERC Alternative Dispute Resolution. The stakeholders do not support the proposal of the Alliance Companies because of the severe restrictions that would be placed on the interim Board of Trustees. In the Alliance Companies' August 27 letter to FERC [pp. 14-15], it set out the following restrictions on the interim Board of Trustees:

> *The interim board would have the responsibility to review and approve any actions proposed by the Alliance Companies respecting market design (i.e., long-term congestion management, energy imbalance market and ancillary services markets) that may be required to achieve a December 15, 2001 start date. In addition, the interim board would have discretion, subject to the following criteria, to review and approve any other action of the Alliance Companies related to the procurement of systems or the adoption of operation practices necessary for initial operation of Alliance Transco:*
>
> 1. *The decision of the interim board must preserve for the Alliance Transco as many decisions as possible and must leave as much flexibility for the Alliance Transco or other authority determined by the Commission to meet its independence requirements, to make adjustments to decisions made by the interim board;*

2. *The decisions of the interim board must facilitate the immediate start-up of operations of Alliance Transco consistent with Order No. 2000 and the Settlement Agreement in Docket No. ER01-123-000;*

3. *The decisions of the interim board must adopt low-cost and cost-effective operation practices; and*

4. *The decisions of the interim board must preserve start up arrangements already made unless there is clear and convincing evidence that such arrangements are unduly discriminatory or preferential.*

While restrictions placed on an interim board are understandable, these restrictions essentially tie the hands of the interim board to implement what the Alliance Companies have already decided, and restrict the view of the interim board to the immediate future; i.e., the December 15, 2001 implementation date. Thus, after a period exceeding one and a half years, there is yet to be an independent board of directors for the Alliance.

Q. HAS THERE BEEN A RELUCTANCE ON THE PART OF THE ALLIANCE OWNERS TO ESTABLISH AN INDEPENDENT BOARD OF DIRECTORS?

A. Yes, it appears so. What seems to be most important to the Alliance Companies is the ability to form a Transco. Upon formation and financing of such an entity, the Alliance Companies can divest their transmission investments to the Transco. Until that time, the Alliance Companies have attempted to maintain control of the formation, development and implementation of the ARTO.

Q. WILL THE ARTO BE OPERATIONAL BY DECEMBER 15, 2001?

A. I do not know for sure, but given the current state of its development and implementation, I do not see how an effective implementation is possible by that date.

On the other hand, that date is not of particular significance to Missouri ratepayers of AmerenUE. The only importance of that date is that AmerenUE wants to secure an order from the Commission allowing it to leave the MISO and join the ARTO by that date. In essence, December 15, 2001 is the FERC's target date for the first day of operations for RTOs throughout the country. With mediations now occurring in the Northeast and Southeast respecting the RTO in each of these regions, I doubt that any of these yet to be formed RTOs will be operational by FERC's December 15, 2001 deadline.

Q. WILL THE MISO AND SPP BE OPERATIONAL BY DECEMBER 15, 2001?

A. Yes, it appears that they will be operational by the FERC December 15, 2001 target date. Currently, both the MISO and SPP are involved in market experiments involving states where retail competition is in effect. A major component of these experiments is the MISO and SPP settlement procedures that determine:

1) supply and demand - quantity of electricity injected and withdrawn by each retail electric provider;

2) energy imbalances - which retail providers are long (injections > withdrawals) and which are short (withdrawals > injections);

3) market prices – the appropriate prices to apply to these energy imbalances; and

4) financial settlements - on net, what each participant owes or is owed.

These are not simple billing systems, but are instead highly sophisticated computer software packages that must be tested rigorously before they are implemented. These tests have been underway in SPP and MISO, but apparently not in the Alliance.

In addition to settlements, the RTO must be ready to perform the duties of the security coordinator. Apparently, the Alliance is hiring the Mid-America Interconnected

Network (MAIN) security coordination group for immediate oversight of this function. Again, this activity requires linking together the metering of the individual Alliance Companies to form an integrated real-time system to monitor the transmission usage within the region. Based on this information and transmission reservations and schedules, the security coordinator must determine the amount of transmission capability available within the ARTO transmission network. Because of the strange geographic shape of the ARTO, network loop flows from surrounding non-ARTO transmission facilities will be a key component of having reliable calculations for transmission capability available for transmission customers.

Q. DO YOU HAVE ANY DOUBTS THAT NATIONAL GRID USA WILL ULTIMATELY BE ABLE TO IMPLEMENT ALL OF THE SYSTEMS NEEDED FOR THE ARTO?

A. National Grid USA runs the transmission network in Great Britain, and I have no reason to doubt its operational competence with respect to a large integrated transmission system.

Q. DO YOU HAVE ANY DOUBTS ABOUT THE ULTIMATE INDEPENDENCE OF THE ARTO?

A. No, I do not. I believe that the FERC is dedicated to the independence of RTOs throughout the country, and will not allow any entity that is not independent, whether an ISO or Transco, to be involved in the market in any way. However, it is important to point out that independence for the ARTO as a Transco will likely mean that the Board of Directors of the managing member becomes the Board of Directors of ARTO, if the managing member is determined to be independent by the FERC.

IV. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION REGARDING AMERENUE'S REQUEST TO LEAVE THE MISO AND JOIN THE ALLIANCE?

A. If the Commission bases its decision solely on the historical performance of the MISO and Alliance, I would recommend against AmerenUE being authorized to withdraw from MISO in order to join the ARTO because of the lack of cooperation with stakeholders exhibited by the Alliance thus far in the development and implementation of the ARTO. If the Commission bases its decision solely on the business model (not-for-profit ISO vs. for-profit Transco), I would recommend against AmerenUE's application because of concerns the RTO market design will result in ARTO taking a position in the market. If the Commission bases its decision solely on the likelihood of the ARTO being operational by December 15, 2001, I would recommend against the AmerenUE application because the ARTO is not far enough along in its implementation.

However, if the Commission bases its decision on the likelihood that the National Grid USA or a similar managing member of the ARTO will turn these situations around, I recommend conditional approval by the Commission for AmerenUE leaving the MISO and joining the Alliance subject to all of the following conditions occurring:

1. The ARTO is approved by FERC as operational by December 15, 2001;
2. The ARTO has a FERC approved permanent Board of Directors and a Policy Advisory Committee of Stakeholders making recommendations to the Board in place by December 15, 2001;
3. The ARTO has FERC approved procedures on the Inter-RTO Coordination Agreement with the MISO operational by December 15, 2001;

4. The ARTO's role in the design of congestion management markets, the energy imbalance market and ancillary service markets is that of a market facilitator, and the ARTO is restricted from PBR that would give it an incentive to take a position in these markets; and

5. The FERC does not order a single RTO in the Midwest.

Q. WHAT MORE SHOULD THE COMMISSION DO REGARDING THESE CONDITIONS?

A. Relating to the first three conditions requiring an operational ARTO by December 15, 2001, instead of issuing its final order on December 5, 2001, the Commission should require testimony to be filed on December 5, 2001 regarding the operational status of the ARTO and schedule a hearing for December 12, 2001 at which time AmerenUE and other parties would provide additional information on the operational status of the ARTO. If any one of these conditions does not appear as if it will be met by December 15, 2001, the parties should make recommendations as to what action the Commission should take to address the situation. The parties' recommendations to the Commission should be based on the specific facts surrounding the then existing operational status of the ARTO.

If the first three conditions are met, then the Commission should issue its order granting conditional approval in which it requires AmerenUE to agree to withdraw from the ARTO if at any time the ARTO is granted PBR that would reward it for taking a position in the market or if the FERC orders a single RTO to be formed in the Midwest.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a AmerenUE for an Order authorizing it to Withdraw from the Midwest ISO to Participate in the Alliance RTO.	)))))	Case No. EO-2001-684

AFFIDAVIT OF MICHAEL S. PROCTOR

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael S. Proctor, of lawful age, on his oath states: that he has participated in the preparation of the foregoing written testimony in question and answer form, consisting of 49 pages of testimony to be presented in the above case, that the answers in the attached written testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S Proctor
Michael S. Proctor

Subscribed and sworn to before me this 12th day of September 2001.

ROSEMARIE RIEDL
Notary Public - Notary Seal
STATE OF MISSOURI
COLE COUNTY
MY COMMISSION EXP. JUNE 1,2005

Rosemarie Riedl
Notary Public

My commission expires

SCHEDULE 1

IMPACT OF WHOLESALE COMPETITION

ON

REGULATED UTILITIES

Impact of Wholesale Competition on Regulated Utilities

By

Michael S. Proctor

August 29, 2001

Scope

The overall scope of this paper is to describe the relationship of competitive wholesale markets for electricity to utilities selling to retail customers at regulated rates. Within this overall scope are the public policy issues regarding the development of Regional Transmission Organizations (RTOs) that are currently being promoted by the Federal Energy Regulatory Commission (FERC). The focus of this paper is on two specific policy questions. First, is it in the public interest to promote a regional transmission system in which transmission built in a specific state is used to serve customers located in another state? Second, is it in the interest of retail customers of a regulated utility for the state to promote competition in wholesale electric markets? The outline of the paper is to first discuss regulated generation and transmission prior to open transmission access; next discuss the effect of open transmission access on wholesale generation and transmission; and finally discuss the issues raised by the recent RTO initiative.

1. Regulated Generation and Transmission Prior to Open Transmission Access

a. Integrated Planning

The regulated model of power systems (generation, transmission and distribution) is, for the most part, vertically integrated. This means that the same company (the electric utility) owns both the power plants that produce the electricity as well as the wires that transmit and deliver the electricity to end-use consumers.[1] That electric utility is responsible for planning for adequate facilities to meet the power requirements (load) of its customers. Those customers are end-use

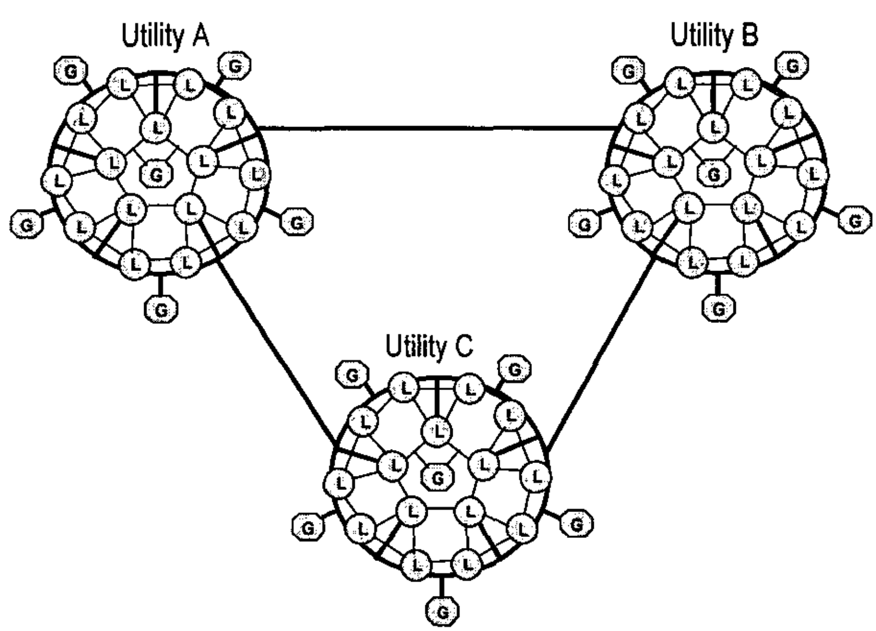
[1] In the case of some municipals and cooperatives, the electric utility is primarily a distribution utility, with only local transmission and limited or no owned generation.

consumers of electricity located within the electric utility's pre-determined service territory. Within that service territory, the electric utility is the only provider of electricity through the integrated power system.

The planning function includes a determination of the physical facilities that will meet load growth at the least cost. Least-cost planning means both deciding what types of power plants to build and where to locate them. The transportation cost of fuel supply is a major cost factor with respect to locating generation, and is evaluated along with the cost of transmitting the electricity from various potential sites to the load.

The utility's investment in wires also involves continual upgrades to the local transmission and distribution system. The distribution system can be envisioned as a local hub (distribution substation) from which lower voltage lines emanate to supply power to individual customers. The local transmission system is made up of the higher voltage lines that feed into these distribution hubs and tie these hubs together into a network. In figure 1 this is shown as the system of load sinks (circles with L) connected together and to generation sources (octagons with G).

Figure 1: Interconnected Transmission Networks



The final component of the power system is the interconnections with neighboring utilities. In figure 1, these interconnections are shown as straight lines connecting the local utility systems – a graphic simplification. By sharing backup (reserve) generation from its neighbors for emergencies, these interconnections reduce the fixed costs of building stand-alone reserve generation for reliability, and through interchange sales, reduce the variable cost of generation

b. Operations

Prior to open transmission access, utilities were not required to sell transmission service to anyone – thus a closed system existed. In this environment, transmission service was typically sold between neighbors as a part of a power purchase; i.e., a bundled package, and the price for transmission was not separate from the price for the generation. These power contracts were approved by the FERC, and as such, were subject to a rate cap. In addition, utilities would sell what is called "interchange power" when a neighboring utility had generation available at a cost below the incremental cost of the purchasing utility. This energy was sold either on the basis of a fixed markup (e.g., 10%) over the seller's incremental cost or on a split savings basis (e.g., halfway between the buyer's decremental cost and seller's incremental cost). There were no tariffed rates for the use of transmission service associated with these interchange power transactions. A utility connected to a low-cost utility to the north and a high-cost utility to the south, could buy from the low-cost utility and resell to the high-cost utility and make a profit. In concept, this profit could be viewed as a payment for the use of the intermediate utility's transmission system. In essence, the low-cost utility was prevented from making a direct deal with the high-cost utility because it had no rights to access the transmission system of the intermediate utility.

c. Rates

Prior to open transmission access, all rates for electricity were bundled unless a utility had filed on a voluntary basis to sell unbundled service (specifically, selling transmission service separate from generation). Total cost-of-service for wholesale service included a return of and on investment in generation and transmission facilities along with any operation and maintenance expenses. In order to determine the revenues that the utility could collect in rates, interchange purchases of power were substituted for higher cost self-generation and profits from interchange power sales were subtracted from total wholesale costs. Because of the lack of open transmission access, utilities that were most highly interconnected had the best opportunities for interchange purchases and sales.

With interchange power sales being made on a bundled basis, it was impossible to separate revenue requirements for generation from those for transmission. If a utility voluntarily unbundled its transmission rates, it would have to attempt an allocation of revenues from interchange sales between generation and transmission. Of course retails rates bundled all of the utility's costs for generation, transmission, distribution and customer services. Absent retail competition, there is no need to tariff unbundled retail rates.

2. Competitive Wholesale Markets in Generation and Open Access to Transmission

a. EPACT '92 and Order 888

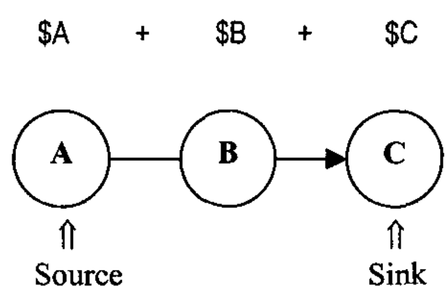
In 1992, Congress passed the Energy Policy Act (EPACT '92) in which utilities were allowed to set up and join in non-regulated generation companies called Exempt Wholesale Generators (EWGs). Prior to EPACT '92, the Public Utility Holding Company Act of 1935 (PUHCA) prevented utilities from building generation for unregulated purposes. The clear intent of EPACT '92 was to encourage the electric industry to move towards deregulation of the generation of electricity, primarily in wholesale electric markets.

From the perspective of economic efficiency, a system of limited access to the use of the transmission system was very inefficient. In 1996, the FERC issued Order No. 888 (Order 888) in which all jurisdictional utilities were required to file Open Access Transmission Tariffs (OATT) allowing transmission service to be provided within each utility's control area (a portion of the network of transmission lines over which the utility has control, usually by virtue of its ownership of those transmission facilities).

The policy envisioned by Order 888 was that there would be non-discriminatory, open access to the transmission system. Under the OATTs, not only utilities, but also power marketers[2] could enter into purchases and sales of electricity spanning the entire transmission system. However, the way the utilities' OATT functioned, a transaction from one control area to another would require the power marketer to purchase transmission service in not only the control areas where the power is generated (source) and delivered (sink), but also in control areas between the source and sink.

Figure 2 is a simple characterization of the transmission business model created by the FERC through Order 888. A power marketer purchases electricity in control area A to sell in control area C. In order for this transaction to take place, the power marketer must pay a transmission rate in control areas A, B, and C. The accumulation of these transmission charges is called "pancaked" transmission rates.[3]

Figure 2: Pancaked Transmission Rates



[2] A power marketer buys power from a generator or other power marketer with the intention of selling that power for a profit.

[3] The Missouri Public Service Commission filed comments in the Notice of Proposed Rulemaking that preceded Order 888. These comments noted that since pancaked transmission charges are based on embedded fixed cost that are not equal to the marginal cost of providing the transmission service (marginal cost includes transmission losses and congestion costs), the result of pancaked transmission rates is not efficient.

b. Competitive Power Procurement: Forward Markets

Power transactions can occur in forward markets (prior to real-time) through both long-term (one-year or longer) and short-term (less than one-year) contracts between sellers and buyers (bilateral contracts). In addition to length, power contracts have several other characteristics. One such characteristic is whether or not they are plant specific; i.e., power can either be purchased from a specific generation plant or it can be purchased from an entire generation system. A second characteristic is whether or not the power is must-take or dispatchable (can be taken in increments at the discretion of the buyer, up to a maximum amount determined in the contract). A third characteristic is whether the price paid for the energy is: fixed at the time of the contract; indexed to increase or decrease with fuel prices; or based on the spot price for electricity.

Typically, utilities will procure contracts for power by issuing requests for proposals (RFPs) to those wanting to sell electricity. In the post EPACT '92 and Order 888 world, those wanting to sell electricity include the power marketing function of utilities selling from EWG (non-regulated) generation, the power marketing function of Independent Power Producers (IPPs), and power marketers that resell power contracted from EWGs or IPPs.[4] For example, contracts for five years or greater tend to attract IPPs to bid new generation units to be built within the service territory of the utility issuing the RFP. In some cases, both EWGs and IPPs have taken the risk of building plants without having a contract in hand. Power can be sold from these "market plants" into spot markets for electricity or offered in response to RFPs.

c. Interchange Sales: Near Real-Time (Spot) Markets

In a market structure having a power exchange, spot prices for electricity are the prices at which any imbalances between demand and supply in real-time are eliminated (i.e., market-

[4] While new contracts directly between utilities for regulated generation are possible, these have become rare in deregulated wholesale market.

clearing prices). These are distinct from even day-ahead markets in which generation is scheduled to supply electricity for the next day.[5] However, where formal real-time markets do not yet exist, electricity can be traded bilaterally on a near real-time basis. Moreover, these trades need to be arranged in time for the transactions to be scheduled on the transmission system. In this bilateral-trade context, spot-market prices can be thought of as the set of prices at which electricity is sold from a day-ahead up to minutes ahead (near real-time), typically with non-firm transmission service that can be interrupted.

In order to have a futures market in electricity, the financial community has offered a standard product at various market hubs. This standard product is 16 hours in length, starting at 6:00 a.m. and running through 10:00 p.m. on week days (on-peak hours). What is reported as spot prices for these market hubs is the average price at which this standard product has traded.[6]

3. Combining Regulated Retail with Competitive Wholesale

a. Expanding Power Purchase and Sales Opportunities

For the regulated utility, competitive power procurement via contracts has become an alternative form of resource acquisition for meeting the load requirements of its customers. In this context, the more competitive this market is, the greater will be the savings in power supply costs for the utility's customers. The degree of competition is affected by the availability and cost of transmission. Most contracts will be for firm power and will require firm transmission service to provide the electricity on a firm basis. If firm transmission is not available for some of the potential bidders, the degree of competition will be diminished. In this context, transmission can be thought

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[5] Day-ahead prices are based on expected (forecasted) demand and supply and may not be the same as real-time prices in which actual demands and supplies must match.

[6] The futures price is the price today at which the standard product is trading for delivery at a future date; e.g., a purchase of 100 MW for 16 hours at $35/MW for delivery 6 months from today.

of in two components: 1) getting the electricity to the utility's service territory; and 2) getting the electricity from where it enters the utility's service territory to end-use customers. Each potential supplier will have a source or set of sources for the generation, and with the utility's service territory as the destination, flow-based power transfer models can determine the impact of each potential contract on the various transmission systems. If any portion of the transmission system is overloaded (congested) by the potential transaction, then that offer cannot be accepted on a firm basis.[7]

While the distance from the supply sources to the destination market may affect the likelihood that some portion of the transmission system will be overloaded, in and of itself, distance is not the only, or even necessarily, the primary factor. On the other hand, distance can affect the competitiveness of bids through pancaked transmission rates and losses. In this context, the more control areas through which a transaction must be arranged, the higher is the transmission cost in terms of having to pay multiple tolls in embedded transmission charges and losses.

In the near real-time markets, a utility can purchase power to substitute for electricity generated from its own generation units when the spot price for electricity is below the utility's incremental cost of generation. The more highly competitive are the spot markets for electricity, the greater is the opportunity for the utility to save on its generation costs by purchasing lower cost electricity. As with contracts, transmission is a limiting factor to competition through congestion and pancaked transmission pricing.

With wholesale competition, markets are opened for utilities to directly sell any excess energy from generation capacity needed to serve peak load, but available for sale at other times. The less

[7] A transaction from a given source to a specified destination has some effect on almost every element of the transmission grid. These effects are measured through what are called transfer distribution factors (TDFs) that specify the percent of power flowing through each transmission element (e.g., line or transformer) in the network. When these TDFs are multiplied by the MW of the transaction, the flow of electricity across each element can be determined. When that flow exceeds the limits on any given element, that element is said to be overloaded.

competitive markets are, the greater are the opportunities for profits in the sale of electricity in the spot market. If profits from spot sales are used to decrease the cost of service to regulated customers, then allowing utilities to exercise market power may result in lower costs for those utilities that have excess base-load (lower-cost) generation. However, as a public policy matter, promoting the exercise of market power is not in the overall public interest. For example, such a policy would be detrimental to utilities that would be the purchasers of spot power as a substitute for their higher cost generation.

b. Misconceptions Regarding Profits from Competition in Wholesale Electric Markets

A major misconception exists with respect to the impact of opening up competition in wholesale electric markets. The fear is that when wholesale markets become competitive, the regulated utility will sell its lower-cost generation to make a profit rather than use that lower-cost generation to serve its regulated customers. Under the type of regulation that occurs in Missouri, a utility has the obligation to serve its regulated customers from the cheapest generation available. To do otherwise would be imprudent. In fact, utilities should aggressively pursue sales in the wholesale market from lower-cost generation not needed to serve its regulated customers.

A second misconception is that profits from sales in the wholesale market go strictly to the shareholders of the utility, with ratepayers receiving no benefits. In states that have fuel adjustment clauses, profits from sales in the wholesale market are used to offset fuel costs on an ongoing basis. In Missouri, profits from sales in the wholesale market are also used to offset fuel costs, but this is done for a historical test year, rather than on an ongoing basis. Regulatory lag between rate cases allows the utilities to keep any profits above those accounted for in the test year. One type of Performance Based Ratemaking (PBR) would put in place some form of profit sharing mechanism to provide an additional incentive for the utility to maximize profits. In each of these regulatory models, ratepayers share in the profits the utility makes in the wholesale market.

c. Enhancing Competition Via FERC Order 888

In Order 888, the FERC expressed a concern that the utility would use its control of transmission within its control area to restrict competition in generation when such competition would disadvantage the utility's own generation. In order to mitigate this exercise of market power, the FERC required the power marketing function of the utility to be separated from the transmission function. What this means is that when the utility desires to either purchase or sell electricity in the wholesale market, it will have to make a request of the transmission function in the same way as any other trader wanting to use the transmission system.

This separation of transmission from power marketing is primarily a separation of operating, not planning functions. In order to serve its native load (those retail customers the utility has an obligation to serve under state law), the utility can forecast what are called new network resources (new generation units used to serve its native load) and the transmission function will evaluate what upgrades are needed to serve the load from these new network resources.

One of the most difficult parts of having a competitive market for generation is upgrading the transmission system to incorporate either EWG or IPP generation that is not committed to serve load at a specific location – market generation. The problem is that the use of the transmission system by market generation will vary with the location of the buyer. Without a long-term contract, it is nearly impossible to determine how the electricity from market generation will affect the transmission system on a long-term basis. With the recovery of-and-on transmission investment being long term, it is impossible to determine which portions of the transmission system to upgrade.

In the regulated model, transmission is built to transfer electricity from generators to consumers for the life of the generation plant. Even when EWG/IPP generation has five-year contracts, the question is whether to make the investment in transmission to meet the needs of the five-year contract. The Order 888 solution to this problem is what the FERC calls *"or"* pricing of transmission.

> *For transmission service requests requiring upgrades to the transmission system, transmission customers pay either the embedded cost or the incremental cost of the upgrade, whichever is higher.*[8] *If the transmission customer is willing to pay, then the utility is required to build the upgrades.*

d. Priority vs. Non-discriminatory Access for Serving Native Load

While more competition in wholesale markets appears to expand alternatives for regulated utilities and therefore lower costs for consumers, greater competition also means competitive uses of the transmission system. Currently, under Order 888, native load has priority use of the transmission system required to serve its native load from its specified network generation resources. The transmission required to serve native load from specified network generation resources cannot be sold as long-term firm reservation to other transmission customers.

What native load priority does not mean is that the utility has priority in the wholesale generation market. For spot-market transactions, short-term bilateral contracts and long-term bilateral contracts for power from an EWG or IPP generation source, the utility must request transmission service on the same basis as any other transmission customer.[9] Thus, competition for the use of transmission can result in the utility not being able to complete transactions that would otherwise provide savings to its customers.

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[8] Under Order 888, a transmission customer wanting to obtain firm transmission service for a five-year contract, for example, would submit its request to reserve firm transmission in the various control areas involved in the transaction. These control areas must determine whether or not firm transmission is available for the proposed transaction. If available, the transmission customer is granted the service subject to paying the set of pancaked transmission rates. If the transmission is not available in any one of the affected control areas, then the request for firm transmission service is rejected. At this point, the transmission customer can request that the utility rejecting the request perform a system impact study to determine what upgrades will be required in order to grant the request.

[9] For a specific wholesale transaction, transmission systems other than those of the utility wanting to make the transaction may be involved. Clearly, on transmission systems of other utilities, the utility wanting to make the transaction would have no priority. But non-discriminatory access goes further by not giving the utility priority on its own transmission system.

It is important to note that under Order 888, where there is competition for the use of transmission facilities, priority is given on a first-come / first-served basis. Thus, the transmission customers either have to arrange their contracts early or speculate by requesting and paying for transmission service before having contracts in place. In this "market design," where the transmission customers have become aware of "chronic congestion" on the transmission system, the firm transmission rights have been reserved on a speculative basis. Those that get there first pay the embedded cost, and those that request service late have the option of paying incremental cost or not completing their transactions. This is a major failure of Order 888, which the FERC has attempted to correct in Order No. 2000 (Order 2000).

4. Regional Transmission Organizations – Enhancing Wholesale Competition

a. Order 2000 Addresses the Shortfalls of Order 888

Competition is restricted in wholesale markets through the physical constraints of the existing transmission system and by the regulatory pricing (rate design) implemented by the FERC. Transmission congestion is inefficiently managed through a system of first-come / first-served, and pancaked rates hindered the market from making transactions that would otherwise have decreased costs to ultimate consumers. In addition, the FERC has received a growing number of complaints filed by transmission customers asserting that utilities were giving preferential treatment to their own generation. The patchwork of control areas operated by utilities is not working well.

In Order 888, the FERC encouraged utilities to join together to form independent system operators (ISOs) in an effort to address the known shortcomings of Order 888. While a few such ISOs were developed and approved by the FERC (California ISO, PJM ISO, New York ISO, New

England ISO, and Midwest ISO),[10] for the most part, the move to regional transmission did not develop throughout the country.[11] Many utilities were reluctant to join in the formation of ISOs. One of the major difficulties with utilities joining an organization with regional transmission pricing was the loss of revenues obtained from pancaked transmission rates. It appeared that the United States was heading toward a system of disconnected and relatively small ISOs with holes and a continuation of pancaked rates. In this regard, FERC Commissioner William L. Massey in his evaluation two and a half years after issuing Order 888 stated:

> *Our experience since the issuance of Orders 888 and 889 had led us to believe that they alone may not be enough to achieve fully competitive power markets and open, non-discriminatory access to the transmission grid. Impediments to full competition that we have recognized include a lack of sufficient separation between generation and merchant functions, multiple pancaked transmission rates within a region, congestion management and loop flow issues, and generation market power that results when market size is constricted by transmission constraints. Many of these are issues with which Orders 888 and 889 did not even attempt to deal.* [**The Electricity Journal**, March 1999, p.13]

The overall goal of regional transmission was and is to enhance competition in the wholesale generation markets. Voluntary groupings by entities that would experience both a loss in transmission revenues as well as the loss of some degree of market power by giving up control of their transmission systems was not likely to result in achieving this goal.

In January 2000, the FERC issued Order No. 2000 (Order 2000) in which it required jurisdictional utilities to form/join Regional Transmission Organizations (RTOs) or file explaining why they had not. The objective of Order 2000 was to fix problems that resulted from the items missing from Order 888: 1) independent operation of the transmission system; 2) sufficient scope

[10] Except for the Midwest ISO, the other ISOs were fairly restricted in terms of geographic coverage, and while the Midwest ISO originally covered the Mid-America Interconnect Network (MAIN) and East Central Area Reliability Coordination Agreement (ECAR) regions (Missouri, Illinois, Wisconsin, Indiana, Michigan, Ohio, Kentucky and Virginia), five of the utilities in Michigan and Ohio region split off to form the Alliance group.

[11] Both the Southwest Power Pool (SPP) and the Mid-Continent Area Power Pool (MAPP) offered regional transmission rates, but early on did not request ISO status from the FERC.

and regional configuration; 3) market-based systems for clearing congestion; and 4) coordinated regional planning for transmission expansion.

1) **Key to Limiting Market Power: Independent Operation:** A major concern that utilities could exert market power through controlling the use of their transmission systems is addressed when the utilities turn over the control of their transmission systems to the RTO.

2) **Key to Eliminating Pancaked Rates: Scope and Configuration:** A major concern that otherwise economic transactions would not take place because of pancaked transmission rates is addressed when transmission service is sold by the RTO at a single rate. In some cases, this is a postage stamp rate (everyone pays the same). In other cases, this is a license plate rate (everyone pays the zonal rate for the zone where the load being served is located).

3) **Key to Viable Market Structure: Congestion Management Systems:** A major concern that first-come / first-served does not allow the least-cost generation to be used to meet load is addressed as the RTOs are required to develop market-based congestion management systems.

4) **Key to Regional Transmission System: Coordinated Planning:** A major concern that transmission capacity that is needed to reliably connect generation and load within a large region would not be built, is addressed as the RTO is required to coordinate transmission planning on a regional basis.

b. Addressing RTO Seams

While Order 2000 addresses many of the shortcomings of Order 888, as RTO filings were made, it became apparent that the scope and configuration of the RTOs being proposed remained relatively small. For example, in the northeast, all three ISOs (PJM ISO, New York ISO and New

England ISO) filed for status as RTOs. With relatively small RTOs, the seams between RTOs present a major problem. Three methods of dealing with seams have been proposed. First, require RTOs to reach seams agreements that make transactions across the seams appear seamless to transmission customers. Second, merge several smaller RTOs into one large RTO. Third, establish an umbrella organization over the smaller RTOs whose primary task is to manage the seams.

At the outset, the smaller RTOs met to work on seams agreements. The objectives of these agreements were to:

1) Set up coordinated systems to allow one stop shopping;
2) Coordinate transmission planning;
3) Consolidate market monitoring efforts;
4) Coordinate congestion management systems; and
5) Eliminate pancaked transmission rates between RTOs.

To date, these efforts have met with some success for the first three objectives. Since several RTOs are in the process of developing their congestion management systems, the coordination of these systems is simultaneously in process. The big stumbling block in seams agreements has been with respect to the elimination of pancaked transmission rates. The problem is with the potential loss of transmission revenues associated with the elimination of pancaking. A potential solution depends on the FERC allowing lost revenues to be included in the calculation of revenue requirements for a transition period of time (three years or shorter). In addition to these voluntary efforts, the FERC has recently approved a mediated seams agreement between the Midwest ISO and the Alliance. Under this agreement, the Midwest ISO and the Alliance will remain separate corporate entities, but will function as a single RTO.

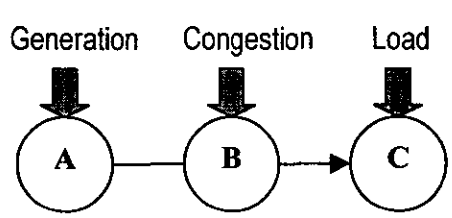
With respect to combining RTOs, the FERC has recently ordered mediations for several entities: 1) In the Northeast, PJM ISO, New York ISO and New England ISO are mediating to become a single RTO; 2) In the Western Interconnection (the western portion of the United States, approximately west of the Rocky Mountains), mediation is focused on having only one RTO; and 3) In the Southeast, Grid South, Grid Florida, Southern Company and Entergy are mediating to become a single RTO. In addition to these FERC ordered mediations, the SPP and the Midwest ISO are in the process of working out the details of a possible merger.

With respect to umbrella organizations, the SPP is proposing that the entire Eastern Interconnection (Northeast, Southeast and Midwest) come under a single RTO for purposes of one stop shopping, planning, market monitoring and coordination of congestion management. This would allow the greatest flexibility for public power (Federal, State, Municipal and Cooperatives) to participate in the development of regional transmission.

c. Regional Transmission and The Public Interest

At the outset, the public interest question was raised regarding the advisability of transmission being used as a vehicle for serving customers on a regional basis. The diagram in figure 3 is a characterization of this issue. Generation located in control area A is contracted to serve load in control area C. The impact on the transmission system is to overload the transmission system in control area B that connects control area A to control area C. In order for the contract to receive firm transmission, the transmission system in control area B must be upgraded to relieve the overloaded condition.

Figure 3: Regional Transmission Public Interest Issue



The public interest issues caused by this example are twofold: 1) cost causation - a transmission pricing structure that will result in the public receiving the benefit to pay for the cost; and 2) states' benefit - building of transmission facilities in a state only when those facilities benefit the public residing in that state.

In Order 888, the FERC asserted its jurisdiction over transmission, and specifically over the pricing of transmission. If the retail customers in control area B remain under regulated rates, it is possible for state commissions to address the cost causation issue by not allowing the utility to impose costs on customers when there is no commensurate benefit from the investment.[12] However, if retail customers are given choice, the supply of electricity will be through wholesale arrangements rather than through a vertically integrated utility system. In this case, transmission is an unbundled wholesale service for which the FERC will establish pricing policies.

In many states, a state regulatory agency is responsible for making the determination that any transmission built within that state is in the public interest – transmission siting.[13] Since states define the public interest in terms of the citizens of the state, where the state regulatory agency has transmission siting authority, there will likely be a conflict in public policy between the state and federal government.

d. Promoting Wholesale Competition and The Public Interest

An important public policy issue is whether enhancing competition in wholesale electric markets is to the overall public benefit, for states with regulated retail electric sales as well as for states with retail competition. To state this differently, will wholesale competition mean everyone is better off, or will there be some winners and some losers? Much of this concern comes from the history of price spikes seen most recently in California and in the past few summers in the Midwest. The price spikes in the Midwest were related to wholesale power markets. Utilities that were

[12] The FERC has not asserted jurisdiction over transmission pricing or cost-of-service for state regulated retail rates.

[13] Missouri does not currently have any laws that require the Commission to approve transmission built by an electrical corporation within its certificated service territory.

dependent on those markets incurred unexpected costs. In essence, utilities that are dependent on wholesale markets will be the losers.

It appears that the lesson learned by utilities is to not be in a position where there is a high probability of needing to purchase power from the wholesale market. One way to hedge this risk is by having sufficient generation reserves that are either owned or under a fixed-price contract. Such strategies may mean higher reserve levels than what utilities have carried in the past for reliability. In essence, generation adequacy may become a question of hedging price risk rather than one of hedging outage risk. However, there are other approaches to hedging price risk including the use of financial instruments and demand-side responsiveness to price signals.[14] In essence, the real lesson to be learned from price spikes in wholesale markets is that both utilities and end-use customers need to develop risk management strategies to deal with price volatility in wholesale markets.

Since wholesale competition is a fact, the policy issue is one of whether enhancing competition in the wholesale markets is in the public interest. Enhancing wholesale competition will not eliminate price spikes, but it will tend to dampen them. First, enhancing wholesale competition will encourage competitors to build new generation. By making wholesale markets more open, competitors will believe that efficient construction and operation of plants will increase the opportunity to make a profit in the wholesale power markets. Second, enhancing wholesale competition will provide better opportunities for small utilities to purchase at prices as low as what may only have previously been available to large, highly interconnected utilities. Third, enhancing wholesale competition will provide stronger financial markets for electricity and thereby give utilities better opportunities to hedge their price risks. Finally, enhancing wholesale competition will

[14] For example, customers can build their own back-up generation to cut back their use of electricity from the utility when prices are high. Missouri utilities have tariffs in place that allow certain customers to receive market-based prices for decreased electricity use during high price periods.

provide a stronger transmission system that will allow greater opportunities for the benefits of weather diversity to mediate high prices in areas of the country experiencing extreme weather conditions. Given the fact of wholesale competitive markets for electricity, states should work together to enhance competition in those markets.

SCHEDULE 2

DTE ENERGY PRESS RELEASE

AUGUST 31, 2001

Friday August 31, 11:59 am Eastern Time

Press Release

SOURCE: DTE Energy Co.

DTE Energy Joins Midwest ISO

DETROIT, Aug. 31 /PRNewswire/ -- DTE Energy Co.'s (NYSE: DTE - news) transmission subsidiary, International Transmission Company (ITC), today will file with the Federal Energy Regulatory Commission to join the Midwest Independent System Operator (MISO) and withdraw from its participation with the Alliance Regional Transmission Organization. ITC will join the MISO in a special membership category designed for independent transmission companies.

``Regional transmission organization (RTO) participation is simply a decision based on which RTO best fits a transmission provider's interests," said Anthony F. Earley Jr., DTE Energy chairman and chief executive officer. ``In the past year, the MISO has evolved into a stronger business model that more closely aligns with DTE Energy's future direction. Led by new management, MISO provides a flexible operating environment for both a transmission-dependent utility such as our Detroit Edison subsidiary and an independent transmission company such as our ITC subsidiary."

Earley indicated that significant factors leading to the decision to join MISO included:

- MISO will recognize and permit the existence of independent transmission companies within its structure, allowing ITC to pursue its business strategies, including becoming an independent entity.
- MISO will customize its service offerings to meet the needs of its customers.
- MISO will provide DTE Energy's Generation and Distribution business units with representation through a stakeholder advisory committee.
- MISO's governance structure provides customers and state regulators with input and participation in the process.
- DTE Energy's opposition to the selection of National Grid as Managing Member of the Alliance, due to National Grid's active market participation in the region.

DTE Energy, parent company to both Detroit Edison and International Transmission Company, is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Detroit Edison is an electric utility serving 2.1 million customers in Southeastern Michigan. Information about DTE Energy is available at http://www.dteenergy.com .

SOURCE: DTE Energy Co.

http://biz.yahoo.com/prnews/010831/def008.html