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September 29, 2004

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SEP 2 9 2004

PUBLIC SERVICE
COMMISSION

Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

RE: ***Investigation Into The Membership of Louisville Gas and Electric Company and Kentucky Utilities Company In The Midwest Independent Transmission System Operator, Inc. – Case No. 2003-00266***

Dear Ms. O'Donnell:

Enclosed please find an original and ten (10) copies of Louisville Gas and Electric Company and Kentucky Utilities Company's Supplemental Testimony, filed in accordance with the procedural schedule established in the above-referenced docket. The notarized verification of Susan F. Tierney, Ph.D., Mark S. Johnson and Michael S. Beer will be provided to this Commission and all parties next week under separate cover.

Further, as Mr. Thompson notes on page 4 of his testimony, the Companies request that the Commission schedule an Informal Conference to hear a full presentation from MISO on the operational and financial aspects of the EMT and Day 2 markets.

Should you have any questions concerning the enclosed, please do not hesitate to contact me directly at 502-627-2573.

Sincerely,

Kent W Blake

Kent W. Blake
Director, Regulatory Initiatives

cc: Parties of Record

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SEP 2 9 2004

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP	)	
OF LOUISVILLE GAS AND ELECTRIC	)	
COMPANY AND KENTUCKY UTILITIES	)	**CASE NO. 2003-00266**
COMPANY IN THE MIDWEST INDEPENDENT	)	
TRANSMISSION SYSTEM OPERATOR, INC.	)	

SUPPLEMENTAL TESTIMONY OF
PAUL W. THOMPSON
SENIOR VICE PRESIDENT, ENERGY SERVICES
LG&E ENERGY LLC

Filed: September 29, 2004

Q. Please state your name, position and business address.

A. My name is Paul W. Thompson. I am the Senior Vice President of Energy Services for LG&E Energy LLC ("LG&E Energy"), the parent company of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (LG&E and KU are collectively referred to as the "Companies"). My business address is 220 West Main Street, P.O. Box 32020, Louisville, Kentucky 40202.

Q. Have you previously testified in this proceeding?

A. Yes. I offered both direct and rebuttal testimony in the initial phase of this proceeding.

Q. What is the purpose of your testimony?

A. I will provide a general overview of the Companies' direct case in this phase of the proceeding, discuss significant events which have occurred since the Companies' analysis of their Midwest Independent Transmission System Operator ("MISO") membership in the initial phase of this proceeding, and discuss the relief being requested in this proceeding.

Q. Please provide a summary of the Companies' direct case in this reopened phase of this proceeding.

A. In addition to my testimony, the Companies are offering the testimony of a number of other witnesses. Michael Beer will discuss the rate and regulatory issues and concerns the Companies have with respect to continued MISO membership, and will address the possibility of withdrawing from MISO and either obtaining reliability coordination services from a third-party provider or joining another Regional Transmission Organization ("RTO"), such as PJM Interconnection, LLC ("PJM") or Southwest Power Pool ("SPP"), all of which would be subject to approval from the Federal Energy

Regulatory Commission ("FERC"). Martyn Gallus will describe the Companies' modeling efforts of the potential benefits from off-system sales volumes and margins under MISO's Transmission and Energy Markets Tariff ("EMT"), which creates the "Day 2 markets", discuss whether exiting MISO will impact the Companies' ability to make off-system sales or the margins thereon, and describe how the Day 2 markets' use of Locational Marginal Prices and Financial Transmission Rights ("FTRs") will impact the Companies' marketing operations and overall business. Mark Johnson will discuss whether there are impediments to joining another RTO other than MISO, and whether the Companies could engage the services of a third party for security coordination without affecting reliability. Mathew Morey will summarize the supplemental analysis conducted by Christensen Associates of the benefits and costs of remaining a member of MISO under the EMT compared with joining PJM, SPP or the Companies operating their own transmission system with a reliability coordinator. Finally, Susan Tierney will clarify the key policy issues and choices that are embedded within the technical issues that are being presented to the Commission in this case. All of that testimony will lead to the conclusion that the relief being requested by the Companies, as described below, is in the public interest as regarding Kentucky ratepayers.

Q. What significant developments have occurred since the hearing in the first phase of this proceeding?

A. Of most significance is the fact that, on August 6, 2004, the FERC, without an evidentiary hearing and over the objections of many MISO members, including the Companies, conditionally and summarily approved MISO's EMT. The Companies currently have pending a request for rehearing of FERC's August 6, 2004 Order.

However, under the EMT, as filed and presently approved, there will be a significant departure from the traditional operation of the Companies' generation assets, which today are controlled by the Companies and are subject to the oversight and jurisdiction of this Commission, and which under Day 2 will be made available to MISO under the terms and conditions of a FERC-approved tariff. Specifically, the Companies and other member utilities will be required to make their generation resources available to the MISO "pool," even if the utilities (including the Companies) wish to use their generation resources solely to self-serve their in-state native load in the most risk-averse and least-cost manner. The EMT mandates that the Companies obtain energy through the MISO pool in accordance with MISO business rules, and does not offer any avenues for the Companies to fully serve their native loads from their own generating facilities outside of scheduling in and/or offering to the MISO Day-Ahead and Real-time pools. That mandatory participation in the Day 2 markets also would open the Companies to a number of financial risks that they do not now bear. Additionally, the Companies will be required to bear a disproportionate share of certain costs associated with the implementation and administration of the EMT. Those issues are discussed more fully in the testimonies of Messrs. Beer, Gallus and Morey and Ms. Tierney.

Another significant development, of course, occurred on June 22, 2004, when this Commission reopened the record in this proceeding and directed the parties to file further testimony. In light of that development, the Companies have looked further at alternatives to MISO membership, and at the impact of remaining in MISO with the implementation of the EMT, as discussed in more detail in the testimonies of Messrs.

Beer, Gallus, Johnson and Morey, and Ms. Tierney. The Companies also commissioned a further cost-benefit analysis explained in detail by Mr. Morey.

Although many technical details concerning how the EMT tariff will be implemented, and how the Day 2 market will operate, are still being developed by MISO, the framework has been established. The Companies believe it would be beneficial for the Commission to hear a full presentation from MISO of the operational and financial aspects of the EMT and the Day 2 market at an informal conference.

Q. Have the Companies reconsidered their request to withdraw from MISO based on any of these events?

A. While we have certainly reevaluated our membership in MISO, and alternatives to that membership, in light of the Commission's Order reopening the record in this proceeding and the FERC's recent approval of the EMT, further analysis continues to show that withdrawal from MISO would be in the best interest of our customers and the Commonwealth of Kentucky.

Q. Is there any indication that the costs of membership in MISO might decrease significantly in the future?

A. No. As depicted on Figure 1 of Mr. Morey's supplemental testimony, MISO's annual operating costs have increased greatly since the entry of FERC Order 2000. And, as discussed above, MISO's EMT will continue to increase the costs that the Companies will have to bear. It is certainly in the public interest to have financially strong utilities, and, as evidenced in the Companies' recent rate proceedings before this Commission, KU and LG&E have exhausted all reasonable internal means of achieving significant cost savings. Thus, any increased costs over the revenues associated with MISO membership would certainly cause the Companies to seek additional revenue to offset those increases.

Q. What relief are the Companies seeking from the Commission in this reopened proceeding?

A. The Companies are asking the Commission for an order granting them conditional authority to transfer functional control over their transmission assets from MISO back to the Companies and entry into an adequate security coordination agreement with a third party, subject to approval by the FERC. With such an order from this Commission, the Companies will then petition FERC seeking exit from MISO and pursuing the transmission operation with reliability coordination alternative. As explained in the testimony of Mr. Johnson, the Companies can operate in this type of configuration, using, for example, TVA's reliability coordination services, without compromising transmission system reliability. And, as explained by Mr. Morey, the cost-benefit analysis commissioned by the Companies show that this type of operation provides the greatest net economic benefits to the Companies and their customers. If FERC determines that the Companies may indeed exit MISO, but nonetheless requires that the Companies be members of some other RTO, then the Companies will seek the approval of the Commission, pursuant to KRS 278.218, to join another RTO. Otherwise, the Companies will pursue a security coordination agreement with a third party and will seek FERC approval and submit any proposed agreement to the Commission for its approval.

Q. What business reasons cause the Companies to seek that relief?

A. As described in detail in the Companies' testimony in the initial phase of this proceeding, the costs of MISO membership now and in the future outweigh any benefits to the

Companies and their ratepayers. And, as discussed above and further described in the testimonies of Messrs. Beer, Gallus and Morey in this reopened phase of the proceeding, MISO's EMT will have additional, significant negative impacts for the Companies and their ratepayers. Specifically, the Companies will face increased costs associated with preparing to operate, and actually operating, under the EMT, and will bear a number of incremental commercial transaction risks, such as those associated with the loss of control over the parties with whom the Companies do business and with hedging against congestion costs with FTRs. In addition, under the EMT the Companies will also lose control over: the dispatch of their generation fleet; the ability to call upon their contracted generation resources; and decisions over which curtailable retail customers to interrupt and at what time interruption will be made. That loss of control will result in having the Companies' resources used for the benefit of the MISO footprint rather than for the benefit of the KU and LG&E ratepayers, and will jeopardize the availability of the Companies' rate base capacity for delivery to native load. Finally, but importantly, the Commission's oversight role will be diluted. All of those business reasons have led us to seek withdrawal from MISO.

Q. Would the Companies' withdrawal from MISO have an unduly negative effect on MISO's operations under its EMT?

A. No, it would not. Indeed, MISO's President and CEO, James Torgerson, was quoted in the Louisville *Courier-Journal* on August 19, 2004 as saying that withdrawal by the Companies would have only "a minor impact" on the new markets. A copy of that report from the *Courier-Journal* is attached as Exhibit PWT-1.

Q. Is it in the public interest for the Companies to remain members of MISO?

A. No it is not. For all of the reasons set forth earlier and explained in more detail in the testimonies of Messrs. Beer, Gallus and Morey, and Ms. Tierney, continued membership in MISO, especially in light of the negative impact which the EMT will have on KU and LG&E, is not in the best interests of the Companies, their ratepayers or the Commonwealth of Kentucky.

Q. Do you have a recommendation for the Commission?

A. Yes. The Commission should determine that the Companies' continuing membership in MISO is no longer in the public interest and should authorize the transfer of the functional control over the Companies' transmission system from MISO to LG&E and KU, subject to FERC approval and conditioned upon the Companies' entering into an adequate security coordination agreement with a third party.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says he is the Senior Vice President of Energy Services for LG&E Energy LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul W Thompson

PAUL W. THOMPSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of September 2004.

Tammy J. Elzy

Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

Business Watch

Mail this page

Area's grid operator plans wholesale power market

The regional utility organization that manages electric transmission for **Louisville Gas & Electric Co.** and Kentucky Utilities is on track to launch a wholesale energy market next year, its top executive said yesterday.

The market will go through several months of tests beginning in September and will open for business March 1, said James P. Torgerson, chief executive of the Midwest Independent Transmission System Operator.

The Kentucky Public Service Commission is considering whether to order LG&E and KU to pull out of the group, which some state officials consider an expensive bureaucracy bringing little benefit to the state. The utilities, part of LG&E Energy Corp., would need federal permission to pull out and would also face exit fees.

Torgerson said in a press conference that a withdrawal would have "a minor impact" on the new energy markets.

Temple-Inland complex offered for $1 million

Temple-Inland's manufacturing, warehouse and office property at 1344 Beech St. is for sale for $1 million.

Commercial broker CB Richard Ellis/Nicklies said the property includes more than 165,000 square feet of building space on 6.7 acres. It is also subleasing Temple-Inland's more than 103,000 square feet of warehouse space at 646 W. Hill St.

Temple-Inland is closing its corrugated cardboard box plant by the end of September, eliminating 126 jobs.

KFC, Long John Silver's get kitchen improvements

Louisville's **QSR Automations Inc.** is providing a system of computer hardware and programming to improve kitchen operations at KFC and Long John Silver's restaurants in the United States.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	))))))	CASE NO. 2003-00266

TESTIMONY OF

SUSAN F. TIERNEY, Ph.D.
ANALYSIS GROUP, INC.

On Behalf Of

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Filed: September 29, 2004

SUMMARY OF TESTIMONY

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony contains two basic pieces. The first sets the economic, historical and federal regulatory context relevant for the Commission's core decision in this case. The second piece, based on my review and consideration of state policies and interests in Kentucky, is in effect a checklist of factors that should be considered by the Commission and LG&E/KU in coming to a decision on whether LG&E/KU should remain a member of the Midwest ISO, join a Regional Transmission Organization and, if so, which one, or operate their own transmission system with reliability services provided by a third party coordinator. The checklist is designed to help the Commission answer the following core question: What approach to compliance with FERC transmission requirements is best for LG&E/KU and the Kentucky residents they serve?[1]

My testimony highlights certain fundamental differences that must be considered in answering this question – that is, the differences among states with respect to electric industry structure and prices, and the structural and functional differences among RTOs that have evolved in this disparate industry context. In the simplest terms, it is no surprise that states with historically high electricity costs have pursued RTO formations containing broad central market features, in part to capture the benefits of wholesale competition and to reduce inter- and intra-regional price disparities. The relevance and benefits of the central-market functions of certain RTOs for consumers of low-cost

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1 In framing this issue, I am aware of the commitments the Companies have made before the FERC in connection with their merger orders in recent years and the need for LG&E and KU to seek relief from these commitments from FERC.

electric utilities has been a more difficult question, deterring the development of "market-oriented" RTOs in these areas in favor of alternative approaches to compliance with FERC requirements. This explains in large measure the tension that exists between those (including the FERC and many relatively high-cost states with retail choice) who seek to expand and make more transparent interstate wholesale power markets, through organized wholesale markets, and those (including companies, customers and elected officials in many individual states with both low-cost supplies and vertically integrated utilities) who are less likely to realize incremental net benefits for their consumers through participation in such organized markets.

In light of these observations, I recommend that the Kentucky Commission approach its review recognizing these economic and structural differences, and with all options in mind: separating from MISO and operating as a stand-alone utility, remaining within MISO, or joining a different RTO/ISO. A utility's choice about what alternative transmission approach to pursue, and a state commission's review of it, have implications (intended and unintended) for more aspects of a company's business than first meets the eye. It is important, therefore, for a state regulatory commission to evaluate the issues recognizing the full range of economic, structural, and jurisdictional implications.

My opinions and recommendations in this testimony are based on my training and direct experience in the industry. Previously, I was a state public utility commissioner, and this helped shape my understanding of how states look at certain policy issues. My understanding of federal policy goals has been influenced by my past service as Assistant Secretary for Policy in the U.S. Department of Energy and by my current consulting experience in different parts of the country. In these contexts, I have been reminded of a fundamental tenet of U.S. energy policy – namely that federal and state interests and goals (however valid from each one's point of view) can be and often are in significant conflict with each other due to state and regional disparities in the underlying technical, economic and demographic factors affecting energy costs.

Through the creation and evolution of RTO's with strong central-market administration functions, FERC has sought to shape wholesale markets in particular forms, and thereby capture associated electricity cost benefits for consumers on a regionally-averaged basis. Where federal authority exists to pursue such goals, this may lead to more efficient wholesale power prices from a *national* or *regional* vantage point. Looking at the same issues from an individual state's perspective, however, might produce a different result, depending upon the circumstances and needs of a particular utility and its consumers in that particular state.

Therefore, in my opinion, state public utility commissioners have a duty to conduct a careful, deliberative review of the cost, reliability and jurisdictional impacts of a jurisdictional utility's form of participation in wholesale markets and its approach to providing transmission service. From a state's point of view, of course, the focus of attention must be on the impacts on customers and companies within that state. This is important because for many low-cost utilities that currently provide reliable service to consumers, the benefits of participating in such a central-market RTO model may be questionable. Where the net incremental economic benefits from participating in certain RTOs may be modest or negative – as for many low-cost utilities – it is reasonable and appropriate for the state commission that regulates those utilities to require a demonstration of compelling need or substantial public benefit to warrant such companies' participation in those RTOs.

In light of these considerations, I attempt in this testimony to establish a conceptual and analytic framework for evaluating the impact on Kentucky utilities and customers of the transmission alternatives facing LG&E and KU. I recommend that the Commission explore the core issues and questions included in Table 1.

Table 1 – CORE ISSUES IN THE KPSC'S REVIEW

ISSUE	***KEY QUESTIONS TO EXPLORE IN EVALUATING LG&E/KU's TRANSMISSION ALTERNATIVES***
CORE ISSUE IN CASE	☑ Which transmission approach is best for LG&E/KU consumers while also meeting the Commission's understanding of FERC requirements?
IMPACTS ON **RETAIL RATES**	☑ What is the likely impact on the retail rates charged to the Kentucky residents and businesses that are the customers of LG&E/KU? ☑ Do the consumers of LG&E/KU get benefits commensurate with the costs assigned to LG&E/KU?
IMPACTS ON **WHOLESALE MARKETS**	☑ Given LG&E/KU's low-cost resource portfolio, are LG&E/KU likely to need to rely on wholesale markets in the future to meet the needs of their retail consumers? ☑ From a short-term perspective, how will the features governing wholesale market interactions affect the dispatch of the LG&E/KU's generating assets for the benefit of Kentucky ratepayers? ☑ From a long-term perspective, do LG&E/KU need to be part of an RTO with a central market in order to assure adequate resources to meet their consumers' needs for low-cost reliable resources?
IMPACTS ON **SYSTEM RELIABILITY**	☑ Are any of the alternatives likely to lead to a meaningful improvement in power system reliability?
IMPACTS ON LG&E/KU'S **ORGANIZATIONAL FORM**	☑ What transmission alternative fits best with Kentucky's expectations for a vertically integrated structure for LG&E/KU?
IMPACTS ON KPSC'S **RETAIL REGULATION** OF LG&E/KU	☑ Which transmission approach best affords Kentucky policy makers the ability to influence the direction of the state's electric industry in the future, including authority over LG&E/KU's resource planning, reliability or wholesale market activities?
EVALUATION OF **BENEFITS AND COSTS** TO LG&E/KU AND THEIR CONSUMERS	☑ What on balance are the likely benefits and costs of each transmission alternative for LG&E/KU consumers, in consideration of both quantitative and qualitative factors: o Total estimated costs and benefits – and net benefits? o Unintended consequences or risks for LG&E/KU and their consumers? o The *allocation* or *distribution* of costs and benefits across states, companies, and customers covered in the analysis? ☑ Will LG&E/KU be a net winner or loser?

Table 1 – CORE ISSUES IN THE KPSC'S REVIEW	
ISSUE	***KEY QUESTIONS TO EXPLORE IN EVALUATING LG&E/KU's TRANSMISSION ALTERNATIVES***
	☑ Are estimates of net benefits based on reasonably conservative estimates versus optimistic estimates? ☑ Is it possible for LG&E/KU and their consumers to get the quantifiable and non-quantifiable benefits of access to wholesale markets administered by an RTO without joining it outright, but with paying their fair share of incremental costs?

II INTRODUCTION AND BACKGROUND

II.A Qualifications

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A: My name is Susan Tierney. I am a Managing Principal at Analysis Group Inc., an economics, business and strategy consulting firm. Analysis Group's address is 111 Huntington Avenue, Boston, Massachusetts, 02199.

Q: WHAT IS YOUR OCCUPATION AND PROFESSIONAL EXPERIENCE?

A: I am a consultant specializing in energy economics and policy. For over 20 years, I have been directly involved in issues that are relevant to this proceeding: economic regulation of utilities, including analysis of traditional retail regulation as well as policies to introduce greater competition into the electric industry; wholesale power market design and analysis; independent system operators ("ISOs") and regional transmission organizations ("RTOs"); and resource planning processes by electric utility companies. I have appeared as a witness before the Federal Energy Regulatory Commission ("FERC"), many state regulatory agencies, arbitration panels and courts, and state and federal legislatures.

Previously, I consulted at Lexecon Inc. and its predecessor company, The Economics Resource Group. Before that, I served as the Assistant Secretary for Policy at the U.S. Department of Energy and held senior positions in the Massachusetts state government as Secretary of Environmental Affairs; Commissioner of the Department of Public Utilities; Executive Director of the Energy Facilities Siting Council; and Senior Economist for the Executive Office of Energy Resources. Prior to my work in state and federal government, I was an Assistant Professor at the University of California (Irvine). I hold a Ph.D. in regional planning from Cornell University (1980). My resume is attached to my testimony as Attachment A.

III PURPOSE AND OVERVIEW OF TESTIMONY

Q: WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY?

A: In light of the critically important issues before the Kentucky Public Service Commission ("KPSC" or "Commission") in this proceeding, I have been asked by Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") to clarify the key policy issues and choices that the Commission must consider here.

Q: WHY DO YOU THINK THAT IT IS NECESSARY OR USEFUL TO HELP CLARIFY THE POLICY ISSUES IN THIS CASE?

A: There are numerous, complex, interrelated and technical issues in this case. Given these issues, it is easy to focus attention on the details of studies of the benefits and costs of LG&E/KU participating in alternative organizational forms of providing transmission service. There will no doubt be significant areas of disagreement in method, data and assumptions used by witnesses to estimate those benefits and costs. In the end, it will be important for the Commission to have focused on those technical details. That said, attention to these details should not distract the Commission from focusing on the fundamental policy choices which are also before the Commission in this case.

As a former state regulator and federal government official, and as a consultant to a variety of clients, I have had the opportunity to observe many regions as they have taken different paths to providing consumers with reliable electric service at just and reasonable rates. I have seen how these regions have attempted to find a workable combination of regulation and market forces to provide benefits to consumers in their area. Drawing upon this experience and these observations, I will provide a policy context and a framework for helping the Commission to consider and weigh the important technical analyses and arguments presented by others in this proceeding.

IV OVERVIEW OF THE CORE ISSUES BEFORE THE COMMISSION IN THIS PROCEEDING

IV.A While there are many detailed technical issues in this proceeding, the essential choices in this proceeding are not complex.

Q: WHAT IS THE FUNDAMENTAL POLICY CHOICE FACING THE COMMISSION IN THIS PROCEEDING?

A: The "core issue" before the Commission is relatively straightforward: what form of compliance with FERC transmission requirements is consistent with the Commission's public interest goals for Kentucky's consumers and electric companies? This question includes *whether* participation in an RTO/ISO meets Kentucky's standard and (if so) *which* RTO platform will provide the greatest net benefits to utilities and their customers, and ensure commitment of utility generation and transmission assets to native load customers.

Q: ARE THERE SPECIFIC FEATURES OR QUESTIONS THAT THE COMMISSION SHOULD CONSIDER IN ITS DETERMINATION OF WHICH OPTION BEST MEETS THE OBJECTIVES DESCRIBED IN THE PREVIOUS QUESTION?

A: Yes. There are a set of fundamental considerations relevant to this determination that the Commission should answer for itself in evaluating its options in this case. I present the major categories of considerations in Table 1, above, and explain them further in Sections VI and VII, below.

Q: WITH THE CORE ISSUE IN MIND, ARE THERE STATEMENTS OF THE COMMISSION THAT HAVE INFORMED YOUR UNDERSTANDING OF THE KEY PUBLIC INTEREST GOALS THAT MIGHT BE RELEVANT IN THIS CASE?

A: Yes. The Commission has issued relevant public interest statements and findings in several recent orders. These provide an important and useful platform for considering the basic components of the core issue in this case.

A commission's policy statements and opinions reveal not only how that commission has interpreted its statutory obligations and resolved matters of law, but also how that state's policy makers have weighed trade-offs, and how they have placed value on one issue over another in exercising discretion in decisions affecting consumers and the industry. I looked for statements which reflected policy preferences and aspirations relating to rates, wholesale competition, reliability, industry form, local control and regulation, which are the key issues affected by the choices before the Commission in this case. Since the end of 2001, for example, the Commission has determined that:

- "The Commonwealth of Kentucky benefits from having some of the lowest electric rates in the nation and it is in the best interests of the Commonwealth and its citizens to maintain these low electric rates in the future."[2]

- "Numerous events and decisions that are beyond the control of Kentucky and its decision-makers are affecting Kentucky's ability to continue to ensure that the low electric rates it presently enjoys will continue into the future."[3]

- "We expect that Kentucky will continue its current regulatory structure as a means of maintaining our low rates and that we will remain vigilant in monitoring issues at FERC and in other states that may impact Kentucky. At present, we do not envision events occurring in Kentucky that will have the sort of material, negative impacts on the electricity utility industry here that have occurred elsewhere in the country."[4]

- "Kentucky's electricity industry is healthy and thriving. The regulatory scheme governing Kentucky's utilities, codified in Chapter 278 of the Kentucky Revised Statutes, has allowed the Kentucky PSC and Kentucky's regulated utilities to develop policies that ensure a sufficient level of reliable service at reasonable prices. This regulatory compact has worked efficiently and effectively for decades. Specifically, it has fostered a stable regulatory environment that has allowed our utilities to proceed with the long-term capital-intensive investment in generation and transmission facilities necessary to serve consumers throughout the Commonwealth of Kentucky. The result: Kentucky today has undisputed claim to the lowest electricity rates in the nation."[5]

- "Kentucky has cooperated in the development of RTOs in an effort to design a system in which restructured and non-restructured states can pursue their policy objectives simultaneously without interfering with each other's interests and welfare. … 'We support federal and other states' efforts to promote the benefits of

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2 Kentucky Public Service Commission, Order, *In the matter of a Review of the Adequacy of Kentucky's Generation Capacity and Transmission System*, Administrative Case No. 387, December 20, 2001, page 89.
3 Ibid.
4 Ibid., at 91.
5 Initial Comments of the Kentucky Public Service Commission, before the Federal Energy Regulatory Commission *in the matter of Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM01-12-000, Dated November 15, 2002, (hereinafter "Initial Comments of the KPSC"), at 6-7.

competitive wholesale markets....Kentucky has achieved these same goals – low electric rates – under existing regulation, but we recognize that alternative approaches may work better elsewhere. We will do our best to cooperate with the federal government and other states to assist them in achieving their goals. Nevertheless, we cannot fulfill our duty to Kentucky customers by allowing them to help fund these efforts unless quantifiable benefits to those customers are clearly demonstrated.' "[6]

- "The allocation of transmission rights is very important to Kentucky. Those who have paid the embedded cost of transmission should retain the right to use all of that transmission capacity. Such retention of these rights will result in an equitable allocation as well as provision of proper incentives to build new transmission."[7]
- "Retail electric customers in a utility's certified territory who have not chosen to receive interruptible service must be the last to be subject to curtailment or interruption of service. There is no exception."[8]
- "This affirmation of this Commission's authority, coupled with the voluntary nature of PJM's energy market for meeting Kentucky Power's native load energy requirements, provides adequate assurances that Kentucky Power's retail energy costs will continue to be fair, reasonable, and relatively stable over time, and not subject to market price variations."[9]

IV.B The decision about whether LG&E/KU's continuing membership in MISO is in Kentucky's public interest may be one of the most important decisions for Kentucky consumers that the Kentucky PSC will make during its term.

Q: WHY IS THIS DECISION SO IMPORTANT?

A: The implications of the "core issue" before the Commission are very broad and long-lasting. They will materially affect the Commonwealth's ability to influence the shape of

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6 Ibid., at 12, quoting the Kentucky Public Service Commission, Administrative Case No. 387, Final Order (December 20, 2001), at 9-10.

7 Initial Comments of the KPSC, at 16.

8 Commonwealth of Kentucky, Public Service Commission, Order, *in the Matter of An* Investigation of the Tariff Filing by Louisville Gas and Electric Company to Implement KRS 278.214, et al., Case Nos. 2002-00345, 2002-00346, 2002-0348, 2002-00349, dated May 28, 2003.

9 Kentucky Public Service Commission, Order, *in the Matter of Application of Kentucky Power Company D/B/A American Electric Power for Approval, to the Extent Necessary, to Transfer Functional Control of*

its electric industry for the future. And they may be difficult if not impossible to revisit at a later date. The different features of the RTOs and alternative transmission frameworks being considered by LG&E/KU affect how well each alternative approach "fits" with the particular needs of LG&E/KU and its consumers. Some of these differences will affect the very influence the state will have in the future over various actions of traditionally regulated power companies in Kentucky.

Among the many issues that could be implicated by the choice of the appropriate transmission approach for LG&E/KU are the following:

- What resource planning and procurement processes will LG&E/KU use – or be allowed to use – in the future to determine what resources to add to serve retail customer needs?
- Will the power plants owned by LG&E and KU be used to meet local needs or the needs of consumers in other states?
- Who will have access to and use of existing transmission assets paid for by LG&E/KU consumers?
- What consumers get the benefit of dispatching – and using up – some of the limited hours of interruptible capacity that exists in interruptible contracts with large industrial customers of LG&E and KU?
- What will be the respective roles of the Commission, the FERC, the RTO, the regulated companies and the competitive market in shaping the outcome of those issues for the benefit of retail consumers in the state of Kentucky?
- And who decides all of those questions over time, once a decision has been made about what transmission approach KG&E and KU should pursue?

For some of the issues listed above, the impacts on LG&E/KU's retail consumers will be roughly the same for any transmission approach approved by the Commission. For other

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Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218, Case No.

questions, the answers – and therefore the impacts on consumers – may vary dramatically, depending upon whether LG&E and KU remain in MISO, participate in another RTO, or provide transmission service to consumers under some other organizational form.

V EVALUATING THE CORE ISSUE IN THIS PROCEEDING: "HOW IT LOOKS DEPENDS UPON WHERE ONE SITS"

Q: PLEASE PROVIDE SOME CONTEXT FOR UNDERSTANDING THE POLICY DIRECTION IN RELEVANT FERC REGULATIONS AND ORDERS.

A: For much of the past decade, FERC has pursued the development and evolution of open access transmission policies with the overarching objective of creating the necessary conditions for wholesale electric competition in the United States. A central element of that policy is FERC's goal of enabling potential users to have non-discriminatory access to use the transmission facilities of electric companies. In FERC's view, such access would provide greater opportunities for buyers and sellers of power to compete, as a way to make wholesale power markets more efficient.

In Order 888 (in 1996), FERC required transmission providers to open their transmission systems to users on a non-discriminatory basis.[10] Subsequently, in Order 2000 (in 1999), FERC encouraged but did not require transmission owners to turn over the operation of their transmission assets to independent grid operators – RTOs – who

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2002-00475, dated May 19, 2004, at 7.

10 FERC, 76 FERC ¶61,347, Promoting Wholesale Competition Through Open-Access Non-discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket No. RM94-7-001, September 27, 1996.

would operate certain transmission functions and services (including certain "ancillary services") so as to further enable the development of wholesale power markets.[11] Less than two years ago, in its Standard Market Design Rulemaking, FERC proposed but ultimately declined to require expansion of the scope of RTOs, and to incorporate the administration and monitoring of wholesale regional power markets, through such means as dispatch of a region's power plants through the central administration of spot-market bidding and dispatch rules.[12]

The issues of voluntary versus mandatory membership in an RTO, or adoption of a particular organizational form to qualify as an RTO have been continuing themes in FERC policies in recent years. Order 2000 itself stated that "we continue to believe ...that at this time we should pursue a voluntary approach to participation in RTOs"[13] and "we will not limit the flexibility of proposed structures or forms of organization for RTOs. ...[W]e designed this Final Rule to be neutral as to organizational form."[14] Specifically, FERC stated that in "many cases, the situation facing transmission owners

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11 FERC, 89 FERC ¶61,285, Regional Transmission Organizations, Docket No. RM99-2-000, December 20, 1999 ("Order 2000"), FERC Order 2000 specifies four characteristics and eight functions of an RTO: independence, sufficient regional scope, operational authority over transmission, and authority to maintain short-term reliability within its footprint. The eight functions are: tariff administration and design, congestion management, managing parallel path flow, serving as a supplier of last resort for ancillary services, operating an Open Access Same-time Information System ("OASIS"), market monitoring, transmission planning, and interregional coordination.

12 FERC, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, Docket No. RM01-12-000 July 31, 2002 ("SMD NOPR"). FERC proposed "to require that all Independent Transmission Providers operate markets for energy and for the procurement of certain ancillary services in conjunction with markets for transmission service. These markets would be bid-based, security-constrained spot markets operated in two time frames: (1) a day ahead of real-time operations, and (2) in real time. The adoption of a market-based locational marginal pricing (LMP) transmission congestion management system is designed to provide a mechanism for allocating scarce transmission capacity to those who value it most, while also sending proper price signals to encourage short-term efficiency in the provision of transmission service as well as wholesale energy, and to encourage long-term efficiency in the development of transmission, generation and demand response infrastructure." SMD NOPR, at 7

13 Order 2000, at 115.

14 Ibid, at 124-125.

in a particular region may influence the appropriate form of organization to propose. In other cases it may be a matter of preference for how the participants wish to do business. ...Because of the differing conditions facing various regions, we offer flexibility in form of organization."[15] As recently as September 15, 2004, FERC noted the distinctions, highlighting industry structure as one of the explanations:

> Since 1997, [FERC] has approved several ISOs and RTOs, five of which have begun market operations... [FERC] has not mandated any particular business model for RTOs and ISOs, which to date have all been not-for-profit entities, making cost review more difficult. Although there are similarities among RTOs and ISOs, each developed independent of the others, using different business models and accounting designs. Moreover, there are significant differences between RTOs/ISOs and vertically integrated public utilities, including some of the functions they perform and the types of costs they incur.[16]

Q: AS FERC HAS PROMOTED ITS POLICIES FOR TRANSMISSION PROVIDERS, HAVE ALL REGIONS IN THE U.S. ADOPTED THE SAME APPROACH TO PROVIDING TRANSMISSION SERVICE, IN TERMS OF ORGANIZATIONAL FORM OR FUNCTION?

A: No. FERC has experienced greater success in seeing its initial vision from Order 888 for open access transmission adopted in *most* parts of the country, as compared to its proposals for a standardized set of market and administrative structures for RTOs. Transmission providers subject to FERC authority in virtually all regions of the country have instituted open transmission access to facilitate wholesale transactions. By contrast, transmission providers in some but not all regions have considered forming or joining an

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15 Ibid, at 125.
16 FERC, Notice, Commission Seeks Comment on RTO/Financial Reporting, Oversight and Cost Recovery Practices, Docket No. RM04-12-000, September 15, 2004.

RTO/ISO that meets all of FERC's RTO requirements including central market administration. In fact, in some parts of the country, such as the South, many states have expressly resisted FERC's policies to promote a "standard market design" through its transmission-related authorities.[17]

Q: IS IT REASONABLE TO EXPECT THAT ALL U.S. REGIONS WILL EVENTUALLY EVOLVE INTO THE SAME OR SIMILARLY-STRUCTURED FERC-APPROVED RTO ORGANIZATIONS?

A: Not in the short run, at least. First, it is my understanding that FERC lacks the statutory authority to impose a common market design on all regions of the country, even if FERC is able to influence such policy through a variety of authorities through which FERC can condition or otherwise pursue its objectives. Secondly, there are long-standing and fundamental differences among various regions in the U.S. in terms of the legal and political structure of local regulation of electric companies; electric system organization and administration; generation technology, costs and fuel mix; transmission system configuration and operation; and perhaps most importantly, the existing structure of electric utilities' provision of electric service to retail customers. Absent federal legislation governing a uniform industry structure across the country, I do not think that it

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17 See, for example, the February 2, 2004 letter signed by Governor Ernie Fletcher of Kentucky, along with the governors of Arkansas, Georgia, Louisiana, Mississippi, Missouri, North Carolina, South Carolina, and West Virginia: "The Southern governors remain adamantly opposed to these and other efforts by FERC to force risky and untested electricity restructuring proposals on regions of the country that have chosen to remain rate-regulated with vertically integrated utilities that provide reliable, efficient, and low-cost electric service. It is a fact that our regulatory system is responsible for our low rates, lack of volatility, and lack of reliability concerns. We have made prudent investments in infrastructure which, in addition to providing the best possible electric service to our citizens, contribute to our ability to attract industry to our region and provide employment and enhanced quality of life opportunities for our residents."

is reasonable in this diverse industry context to expect that there is a single organizational structure and market design that is right for all parts of the industry throughout the U.S.

Q: SO, IS THIS WHY YOU SAID EARLIER THAT "HOW IT LOOKS DEPENDS UPON WHERE ONE SITS"?

A: Yes.

Q: PLEASE DISCUSS FUNDAMENTAL ELECTRIC PRICE DIFFERENCES AND ORGANIZATIONAL PREFERENCES THAT EXIST AMONG REGIONS.

A: As the Commission surely knows, there are many significant differences among the states, in terms of their electric companies, their consumers, their basic economies, and so forth. For our purposes here, one of the most important distinctions is the retail price of electricity. This aspect of a state's electric industry stems from many factors – the availability and type of indigenous resources/fuels, the type of utility investment decisions made in the past, electricity demand, the financial health and management strengths of electric companies, the approach to utility regulation, and others.

Regions and states like Kentucky with low electricity prices tend to be characterized by access to relatively low- and stable-priced indigenous primary fuels to generate power in local power plants, and by a relatively low-cost portfolio of power plant ages and technology types. Not surprisingly, these factors – and moreover, the attendant low prices – tend to be a defining feature of electric industry regulatory policy and approaches in such states, including views about the benefits of adopting large, organized wholesale market structures and designs of the sort proposed by FERC in recent years. As a general matter, the states with low electricity rates have moved less aggressively to adopt centrally organized wholesale power markets as a way to reduce wholesale – and by extension, retail – electricity prices.

In Attachment B, I provide a map of the Lower 48 states in the U.S., with the states organized to show two pieces of information: their relative retail electricity prices, and whether the utilities in their states have decided to participate in what I've called a "centralized" wholesale power market. With the exception of Kentucky, which is singled out on this map, I've grouped states according to the boundaries of existing and developing RTOs.[18]

It should come as no surprise that the states in the regions with high electricity rates tend to have been the first movers in the transition to a restructured electric industry – with support for organized wholesale markets, adoption of policies to allow retail access, and de-integration of previously vertically-integrated electric companies. Some of these states with high retail electricity rates have required utilities to sell off their power plant assets as a way to help "pay off" certain "stranded costs" associated with past, uneconomic power plant investments, and to require the utility to purchase power from wholesale markets as the means to supply local retail consumers who decide to retain the utility as their local electricity supplier. In effect, states with high retail electricity rates – those in the Northeast, Mid-Atlantic region, Texas, California, and parts of the MidWest, have embraced organized wholesale markets and retail competition as ways to relieve the pressure of high retail rates. These states have reorganized their

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18 The regional boundaries presented in Attachment B are not meant to represent the exact boundaries of ISO/RTO regions, which tend not to follow exactly the contours of state boundaries as depicted in the map. Please see the notes to Attachment B.

electric industries, and have sought to open up transmission paths to enable local buyers to have access across a wide geographic scope to lower-cost sources of power in distant locales.

To a certain degree, many states with retail choice have felt that their utilities need to form and participate in transmission organizations with central markets in order to help assure adequate and competitively priced supplies for retail competitive suppliers and for load-serving entities who own little or no generating resources and who still have obligations to serve customers. Consequently, in many of these states and regions, there has been a relatively deliberate transition toward reliance on a regional organization that independently administers not only the open access transmission tariff, but also a set of organized electric markets along the lines promoted by FERC in its SMD proposal.

By contrast, states with low retail electricity rates have tended to retain their electric industry's vertically-integrated structure, with the local utility owning power plants, transmission lines, and local distribution facilities, and providing much of the power to retail consumers from those same owned power plants. In many of the states, the availability of relatively low-priced indigenous resources and historical power plant investments mean that power supplies from the utility's own generation resources are often lower cost than those that can be obtained from wholesale markets, and retail electricity rates are among the lowest in the nation.[19] The Commission itself has observed that these parts of the U.S. are the places where low electricity costs have left

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19 As noted by FERC, "...regions with low percentages of indigenous low-cost hydroelectric and coal resources tended to have organized markets in place. This is in contrast to regions with high percentages of indigenous low-

the states "unconvinced that there is anything wrong with the retail electricity markets"[20] in those states.

Indeed, as portrayed in Attachment B, Kentucky finds itself in the situation where the retail rates charged to its customers are significantly lower than the rates charged in neighboring regions, and across the country. It would not be surprising to learn that the net benefits of Kentucky utilities joining an RTO with a centralized market would be relatively small, if positive at all, in light of the starting point of Kentucky's low rates. Indeed, Kentucky's low costs reduce the incentive for the state's utilities to move toward a centralized market RTO, where the benefits of low-cost generation[21] would logically flow more to consumers in higher-cost states. And unless the allocation of such an RTO's administrative costs were structured to compensate or reflect these differential benefits (e.g., through not allocating administrative costs to a utility's loads that are self-supplied), consumers in a low cost state might be expected to capture small to negative benefits of having their utilities join such an RTO.

Q: DO SUCH CIRCUMSTANCES MEAN THAT THERE ARE NO BENEFITS TO BE OBTAINED FROM RTOS IN LOW-COST STATES?

A: No, and I do not mean to suggest that it is inappropriate for FERC to encourage RTO participation as a means to improve the conditions for wholesale competition generally.

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cost resources, which tended to stay in traditional regulated structures. FERC, *State of the Markets Report*, January 2004 ("FERC State of Markets Report"), at 20.

20 "Kentucky has the lowest average electricity costs in the nation. In addition, our electricity service is highly reliable. Afflictions experienced in electricity markets elsewhere in the nation – brownouts, rolling blackouts, price spikes, market meltdowns – have not occurred in Kentucky; nor will they, under the present regulatory environment….[T]he Kentucky PSC remains unconvinced that there is anything wrong with the retail electricity markets in Kentucky." Initial Comments of the KPSC, at 5.

Even so, such participation at this time is not necessarily the best option for all utilities and all states, meaning that utility and Commission review should pay close attention to making sure that the benefits of participating in a particular RTO are (a) suited to the needs of the industry and consumers in a particular state, and (b) worth whatever costs it takes to realize those benefits. In short, the benefits of adopting a particular form and function for providing transmission services depend upon whether that particular form and function offers sufficient benefits to outweigh the costs.

Q: IN CONSIDERING THIS QUESTION OF PROPER ALIGNMENT BETWEEN A PARTICULAR TRANSMISSION APPROACH AND THE NEEDS OF A PARTICULAR UTILITY AND ITS CUSTOMERS, PLEASE DESCRIBE THE DIFFERENT TYPES OF ISOs/RTOs CURRENTLY IN PLACE IN THE U.S.

A: At this point in the evolution of RTOs in the U.S., there are two basic organizational forms or structures for transmission organizations. For example, FERC has distinguished between the two types – as regions with organized markets ("Market Regions") and those without ("Non-Market Regions").[22] The Market Regions are parts of the U.S. that have adopted RTOs with forms and functions along the lines of FERC's SMD proposal (and the regions I previously described as having access to "Centralized Markets"). As of 2003, these regions were New England, New York, PJM, ERCOT (Texas), and California. With implementation of MISO's Day 2 markets, MISO will join the Market

21 The retail rates presented in Attachment B reflect in part the relatively low fixed and variable costs of Kentucky generation plants, as well as transmission, distribution and administrative costs.
22 FERC, *State of Markets Report*, at 19.

Region group. In Non-Market Regions, the SMD model has not been adopted, even in one region (the "SPP" region) which has been approved as an RTO.

Q: HOW SHOULD THIS INFORMATION ABOUT "MARKET REGIONS" VERSUS "NON-MARKET REGIONS" HELP INFORM THE COMMISSION'S DELIBERATIONS ABOUT THE "CORE ISSUE" IN THIS CASE?

A: A state's decision about whether a particular utility should take on the additional functions, obligations, costs and responsibilities associated with a market-oriented RTO must focus on whether such features are needed and appropriate for the utility and its consumers. Even states and regions having the same goals (e.g., to foster and reap the benefits from competition in wholesale electric markets) come to the RTO question from very different contexts, cultures, forms of industrial organization, and comparative strengths and weaknesses from the point of view of company financial and managerial attributes. A state commission might find it reasonable for one of its jurisdictional utilities to pursue one approach while finding that a different approach is preferable for another jurisdictional utility and its consumers.

VI THE COMMISSION SHOULD LOOK AT IMPACTS ON RATES, WHOLESALE COMPETITION, RELIABILITY, INDUSTRY STRUCTURE AND REGULATION AS THE COMMISSION CONSIDERS THE "CORE ISSUE" IN THIS PROCEEDING.

Q: PLEASE EXPLAIN FURTHER WHAT YOU THINK ARE THE MOST IMPORTANT IMPACTS THAT THE COMMISSION SHOULD TAKE INTO CONSIDERATION AS IT DECIDES THE "CORE ISSUE" IN THIS INVESTIGATION.

A: In my opinion, the Commission should consider the impacts of its choices on five issues: retail rate impacts on LG&E/KU consumers; impacts on wholesale competition in the markets that serve LG&E and KU consumers; impacts on reliability of the system that serves LG&E and KU consumers; impacts on the form of the electric industry that provides service to LG&E and KU consumers; and impacts on the ability of the Commission to regulate in ways that influence all of these factors in the future. If the Commission explores these impacts with respect to the alternative ways in which LG&E/KU could provide transmission service, then the Commission will be able to make a well-informed and well-considered decision.

Let me further explain the types of questions that the Commission should ask in order to examine the impacts of alternative transmission choices (which I summarized previously in Table 1).

VI.A Effect on retail rates of LG&E/KU consumers

Q: WHAT ARE KEY CONSIDERATIONS REGARDING IMPACTS ON RETAIL RATES?

A: Rate impact issues are obviously at the core of this Commission investigation. The Commission must determine which transmission compliance approach is consistent with the Commission's goal of preserving low rates for LG&E/KU consumers. The central rate-impact question for each transmission alternative is, of course, what are the total rate impacts for LG&E/KU consumers, but there are other significant aspects of the rate-impact question as well:

- Does a particular approach to transmission compliance offer more or less opportunity for rate stability for LG&E/KU consumers (including through the ability of the LG&E/KU to control their assets and decisions about their use)?

- Given a particular form of transmission compliance, how are the costs and benefits distributed among its members and users? On balance – looking at any and all services provided by an RTO – do participants pay their fair share of costs relative to the benefits they realize from participating in that RTO, or is there cost shifting with some members or classes of members subsidize other members? In particular, do the consumers of LG&E/KU get benefits commensurate with the costs assigned to LG&E/KU?

- Are there any negative implications for the financial health of LG&E/KU and therefore, indirectly, for the rates of their retail consumers, associated with LG&E/KU pursuing one transmission compliance approach over another, including participating in one RTO or another?

VI.B Effects on wholesale competition in the markets that serve LG&E and KU consumers

Q: WITH REGARD TO IMPACTS ON WHOLESALE COMPETITION, WHAT ARE THE KEY ISSUES THE COMMISSION SHOULD CONSIDER?

A: As the Commission has noted elsewhere, retail consumers in Kentucky could derive benefits from access to wholesale supplies available in a healthy competitive regional power market. In my opinion, the Commission's interest in examining impacts on wholesale competition in this proceeding is to determine whether an LG&E/KU decision not to participate in an RTO would adversely impact wholesale competition *and, as a result,* adversely impact Kentucky's retail consumers. This means that the Commission's focus should not be on wholesale competition impacts for their own sake, but should instead concentrate on whether LG&E/KU's approach to satisfying FERC's transmission requirements would negatively impact their retail customers because of tangible harm to wholesale competition. Additionally, the Commission should assume that whatever form of transmission alternative is appropriate for LG&E/KU, it can and should continue to hold the companies accountable to participate in wholesale markets where such provides net benefits to consumers.

The issues for the Commission to consider in this regard include the following:

- Given LG&E/KU's resource portfolio, do they rely on wholesale markets now, and are they likely to need to do so in the near-term or long-term future?

- In each form of transmission compliance (e.g., participation in a particular RTO or as a stand-alone transmission provider), can the consumers of LG&E/KU get access to the benefits of market forces in wholesale markets? If so, how would that happen – through bilateral transactions, or participation in spot markets, or both?

- Do LG&E/KU need to be actual participants in an RTO with a centralized market in order to access that wholesale market?

- Are there significant differences among the alternative RTOs with regard to the way in which LG&E/KU would be allowed and/or required to participate in such wholesale electricity markets?

- In light of Kentucky's unique statutory requirements, would LG&E/KU's participation in a particular RTO cause the companies' assets to be used for certain services in the future which differ inherently from the service traditionally provided by these assets for LG&E/KU and its consumers (e.g., use of these assets to provide electric energy and capacity in the context of a bundled supply for retail consumers)?

- Who would determine economic dispatch of generation owned by LG&E/KU and on whose behalf those assets are dispatched?

VI.C Effects on system reliability for LG&E and KU consumers in the short term and long-term

Q: WHAT ARE THE SYSTEM RELIABILITY IMPACTS YOU THINK THE COMMISSION SHOULD CONSIDER?

A: As was apparent in the August 2003 Blackout that affected 50 million consumers in parts of the Midwest and Mid-Atlantic areas, an electric system's reliability can be affected by actions and practices that take place in areas quite distant from a particular utility and its consumers. Electric system planners have known this for decades. Of course, one of the principal – and, indeed, original purposes of RTOs from FERC's point of view[23] – was to help create transmission-related enhancements that would benefit system reliability. And yet, not all RTOs adopt the same practices, institutions, standards, and techniques for assuring reliability. Therefore, the Commission should examine reliability impacts of RTO choices. Especially given Kentucky's statutory requirements (KRS § 278.214) which set forth the relative priority of curtailment or interruption of service to firm retail customers in the event of an emergency on a Kentucky utility's transmission facilities, the Commission should specifically inquire as to each RTO's consistency with Kentucky law. Important questions include:

- Are there significant differences among alternative forms of transmission compliance, with regard to their reliability policies, standards, protocols or practices which would affect the reliability of service to LG&E/KU and their customers? Would participation in a particular RTO affect the ability of LG&E/KU to influence these reliability-related impacts?

- Are the reliability policies, standards, protocols and practices of a particular RTO consistent with Kentucky's statutory requirements to assure that its consumers have the highest priority of service?

- From the perspective of assuring the availability of adequate resources consistent with a reliable electric system, how would participation in a particular RTO affect either LG&E/KU's investment decisions (e.g., for transmission enhancements, or generation assets) or expenditures on demand-

23 See footnote 12, above.

side measures to curtail or reduce loads? Who will influence the portfolio of resources available to consumers in Kentucky?

- Assuming LG&E/KU's participation in a particular RTO, who gets the economic benefit of generation facilities previously supported in the rates of LG&E/KU's retail consumers?

- Assuming LG&E/KU's participation in a particular RTO, who is likely to plan for, build, invest in, use, and pay for transmission facilities? Who gets rights to existing and new transmission? Who gets to use transmission capacity previously supported in the rates of LG&E/KU's retail consumers?

- Assuming LG&E/KU's participation in a particular RTO, what entity (or entities) will have responsibility to plan for and administer demand-side programs? On whose behalf will the resources available through such programs be deployed?

- How do the answers to the previous questions compare to a situation in which LG&E/KU pursued a stand-alone form of transmission compliance rather than participation in one of the RTO alternatives under examination in this case?

VI.D Effect on industry structure in Kentucky

Q: WHAT SHOULD THE COMMISSION CONSIDER WITH REGARD TO THE IMPACTS OF ALTERNATIVE TRANSMISSION COMPLIANCE APPROACHES ON LG&E/KU's ORGANIZATIONAL STRUCTURE?

A: I believe that there could be initially subtle but still important implications in the long run for electric industry organization and structure associated with the requirements of certain RTOs. One set of questions the Commission should ask has to do with whether participation in a particular RTO will create tensions with the vertically integrated structure that the Commission (and the Governor of Kentucky) has so far stated as the preferred organizational form for LG&E/KU. For example:

- What form of transmission compliance fits best with Kentucky's expectations for the organizational structure of LG&E/KU – with their vertical integration?

- What pressures will be brought to bear (by federal regulators, by market participants, by the RTO itself) on whether LG&E and KU remain vertically integrated or restructure their organizational form on the margin (e.g., could a currently vertically-integrated utility be allowed to build generation to serve its own load, would the state have the ability to make that determination, and who will make decisions about the process that a company (like LG&E and/or KU) must use to determine the appropriate resource portfolio)?

- Given the Commission's goals for organizational structure for LG&E/KU, do the elements of a MISO Day 2 market (for example) provide significant incremental benefits for a company like LG&E/KU, which is likely to continue to rely upon its own planned/owned/contracted-for resources – and not on spot markets – for the foreseeable future?

VI.E Effects on retail regulation

Q: WHAT ARE THE KEY CONSIDERATIONS REGARDING IMPACTS ON RETAIL REGULATION?

A: This case presents the core issue about which RTO configuration or alternative form of transmission compliance affords the greatest net benefits to LG&E/KU consumers. In understanding some of the long-run implications of this decision, the Commission should ask and answer the question of what difference, if any, each approach has for the on-going ability of the Commission to influence the kinds of issues listed above in the future. In other regions of the country, one can observe that state regulators have much greater ability to influence (formally and informally, directly and indirectly) the conduct of transmission providers when those utilities and other transmission organizations operate within a single-state environment (e.g., Texas, California, New York), as opposed to approaches where the grid operator's geographic scope spans many states. Therefore, the

Kentucky Commission may want to consider this issue directly as it reviews the transmission alternatives available to LG&E/KU.

- Which regulators (Kentucky's or FERC, or other states) will have the greatest influence the kinds of issues mentioned above?

- What has been the experience in other states with regard to a state commission's ability to influence RTOs whose boundaries exist within a single state (e.g., New York, Texas) as opposed to a multi-state RTO?

VII GUIDANCE ON EVALUATING THE EVIDENCE ON THE BENEFITS AND COSTS OF ALTERNATIVE FORMS OF TRASMISSION COMPLIANCE

Q: FINALLY, WHAT IS YOUR PERSPECTIVE ON HOW THE COMMISSION SHOULD EVALUATE THE QUANTITATIVE INFORMATION ON BENEFITS AND COSTS THAT IT WILL RECEIVE FROM OTHERS IN THIS CASE?

A: To determine the relative importance and accuracy of the analyses performed by the benefit/cost witnesses in this case , I respectfully suggest that the Commission consider at least the following:

- Examine the extent to which estimates of benefits, costs and net savings are based on conservative or optimistic assumptions. Given the importance of the decisions facing the Commission, it would be reasonable and prudent to rely on conservative assumptions, and base its decision on the totality of the evidence before it.

- Seek to identify possible risks and uncertainties, including unintended and non-quantifiable consequences of participating in one RTO versus another.

- Look at how costs and benefits are distributed – in other words, does everyone have an "average" amount of each type of benefits and costs, or are some parties benefiting at the expense of others? Are the benefits what economists call "transfers" from one group to another, rather than net benefits (or true economic efficiencies) to all? Do some groups get known benefits while others receive speculative benefits?

- In light of the answers to the questions above, look for who are the likely beneficiaries, and who are those most likely to be net losers. Are LG&E/KU customers likely to be net winners – given either known or speculative benefits and costs? If LG&E/KU customers "supply" more benefits to others than they achieve, how are they "charged" for participating?

- Is it possible for LG&E/KU customers to get the benefits of using the services of another RTO without joining it outright, and do so in a way in which they are not "free riding" but in fact pay their fair share of incremental costs?

If the Commission focuses on these issues, then the Commission will have significant relevant information to assist it in making the core decision in this proceeding: *which transmission approach is best for LG&E/KU consumers while also meeting the Commission's understanding of FERC's requirements?*

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

ATTACHMENT A

RESUME OF SUSAN F. TIERNEY, Ph.D.

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Dr. Tierney, a Managing Principal at Analysis Group, is an expert on energy policy and economics, she has consulted to business, government policy makers, and other organizations on energy markets, economic and environmental regulation and strategy, and electric facility projects. Her expert witness and business consulting services have involved electric industry restructuring, market analyses, wholesale and retail market design, contract disputes, asset valuations, regional transmission organizations, generation and transmission projects, energy facility siting, natural gas markets, electric system reliability, and environmental policy and regulation. She has participated as an expert and advisor in civil litigation cases, regulatory proceedings before state and federal agencies, arbitrations, negotiations, mediations, and business consulting engagements.

Prior to joining Analysis Group, she was Senior Vice President at Lexecon, where her practice areas included analysis, strategy and expert witness services in the electricity and natural gas industries, energy policy, public policy and regulations, and environmental economics and policy.

She has also served as the Assistant Secretary for Policy at the U.S. Department of Energy, Secretary for Environmental Affairs in Massachusetts, Commissioner at the Massachusetts Department of Public Utilities, and Executive Director of the Massachusetts Energy Facilities Siting Council. She recently served as chair of the Massachusetts Ocean Management Task Force.

Dr. Tierney has authored numerous articles, speaks frequently at industry conferences, and served as a formal facilitator and expert mediator of disputes. She serves on a number of boards of directors and advisory committees, including the National Commission on Energy Policy. She is chairman of the board of the Energy Foundation and the Energy Innovations Institute; a director of Catalytica Energy Systems Inc., Clean Air-Cool Planet, the North East States Clean Air Foundation, and the Climate Policy Center, and the Policy Advisory Council of the China Sustainable Energy Program. She has taught at the University of California-Irvine, and she earned her Ph.D. and M.A. degrees in regional planning at Cornell University and her B.A. at Scripps College.

EDUCATION

1980	Ph.D. in Regional Planning, Public Policy, Cornell University, Ithaca, NY Dissertation: *Congressional policy making on energy policy issues*
1976	M.A., in Regional Planning, Public Policy, Cornell University, Ithaca, NY
1973	B.A. in Art History, Scripps College, Claremont, CA
1971-72	Studied Political Science, L'Institut d'Etudes Politiques, Paris, France

PROFESSIONAL EXPERIENCE

2003-present	Analysis Group, Inc., Boston, MA Managing Principal
1999-2003	Lexecon, Inc., Cambridge, MA (formerly The Economics Resource Group, Inc.) *Senior Vice President*
1995-1999	Economics Resource Group, Inc., Cambridge, MA *Principal and Managing Consultant*
1993-1995	U.S. Department of Energy, Washington, DC *Assistant Secretary for Policy*
1991-1993	Commonwealth of Massachusetts, Executive Office of Environmental Affairs, Boston, MA *Secretary of Environmental Affairs*
1988-19991	Commonwealth of Massachusetts, Department of Public Utilities, Boston, MA *Commissioner*
1984-1988	Commonwealth of Massachusetts, Energy Facilities Siting Council, Boston, MA *Executive Director*
1983-1984	Commonwealth of Massachusetts, Executive Office of Energy Resources, Boston, MA *Senior Economist*
1982-1983	Commonwealth of Massachusetts, Energy Facilities Siting Council, Boston, MA *Policy Analyst*
1982	National Academy of Sciences, Washington, DC *Researcher*
1978-1982	University of California at Irvine, Irvine, CA *Assistant Professor*

transmission congestion in wholesale power contract for standard offer service. Expert Report, September 19, 2001; deposition, October 15, 2001.

- **Cross-Sound Cable Company LLC**
  Before the *Connecticut Siting Council*, on the public benefits of the proposed Cross Sound Cable Project's *Application for a Certificate of Environmental Compatibility and Public Need*, Docket No. 208. Prepared direct testimony, July 23, 2001; oral testimony under cross-examination, October 24-26, 29-30, 2001.

- **Sithe New England (Sithe Edgar LLC, Sithe New Boston LLC, Sithe Framingham LLC, Sithe West Medway LLC, Sithe Mystic LLC)**
  Before the *Federal Energy Regulatory Commission, in the Matter of NSTAR Electric & Gas Corp., v. Sithe Edgar LLC, Sithe New Boston LLC, Sithe Framingham LLC, Sithe West Medway LLC, Sithe Mystic LLC, and PG&E Energy Trading*, Docket No. EL01-79-000. Affidavit comparing historical cost recovery by Boston Edison for its portfolio of fossil generation units (pre-divestiture) under rate regulation, versus Sithe's revenue recovery for these same units (post-divestiture) under market prices, June 5, 2001.

- **NRG Energy Inc. and Dynegy Holdings Inc.**
  Before the *Public Utilities Commission of Nevada*, In Re: petition of the Attorney General's Bureau of Consumer Protection to issue an Order staying further proceedings regarding divestiture of Nevada's electric generation assets and to open a docket to consider whether to issue a moratorium on divestiture in Nevada. Supplemental prepared direct testimony on behalf of Valmy Power LLC, April 6, 2001; testimony under cross-examination..

  Before the *Public Utilities Commission of Nevada*, In Re: petition of the Attorney General's Bureau of Consumer Protection to issue an Order staying further proceedings regarding divestiture of Nevada's electric generation assets and to open a docket to consider whether to issue a moratorium on divestiture in Nevada, prepared direct testimony on behalf of Reid Gardner Power LLC and Clark Power LLC, April 3, 2001; testimony under cross-examination.

- **Sithe New England, LLC**
  Before the *Federal Energy Regulatory Commission, In the Matter of Maine Public Utilities Commission and The United Illuminating Company v. ISO New England, Inc.*, affidavit on the role of price "spikes" in compensating generators for the services that they provide in the region, September 7, 2000.

- **Arkansas Electric Distribution Cooperatives**
  Before the *Arkansas Public Service Commission, In the Matter of a Generic Proceeding to Establish Uniform Policies and Guidelines for a Standard Service Package.* Prepared joint reply testimony (with Janet Gail Besser), July 21, 2000; prepared joint surreply testimony (with Janet Gail Besser), August 3, 2000.

- **TransÉnergie U.S.**
  Before the *Connecticut Siting Council*, on the public benefits of the proposed Cross Sound Cable Project. Expert report, July, 2000; prepared direct testimony, September 20, 2000; oral testimony, September 27, 2000; supplemental written testimony, December 7, 2000; oral testimony under cross-examination, December 14, 2000; oral testimony January 9-11, 2001.

- **SCS Energy Corp.**
  Before the *New York State Public Service Commission*, on the economic and environmental impact of a new combined cycle power plant in Queens, NY, June 19, 2000.

- **Reading Municipal Light Department**
  Before the *Massachusetts Energy Facilities Siting Board, Docket No. EFSB 97-4*, on the economics and need for a new natural gas pipeline, June 19, 2000; testimony under cross-examination September 19, 2000, September 21-22, 2000, October 5, 2000, and October 17, 2000.

- **Fitchburg Gas and Electric Light Company**
  Before the *Massachusetts Department of Telecommunications and Energy, Docket D.T.E. 99-66*, on gas and electric company rate design policy, testimony under cross-examination, January 14, 2000.

- **FirstEnergy Corp.**
  Before the *Public Utilities Commission of Ohio*, In the Matter of the Application of FirstEnergy Corp. on behalf of Ohio Edison Company, the Toledo Edison Company, and The Cleveland Electric Illuminating Company: for Approval of an Electric Transition Plan and for Authorization to Recover Transition Revenues (Case No. 99-1212-EL-ETP); for Approval of New Tariffs (Case No. 99-1213-EL-ATA); for Certain Accounting Authority (Case No. 99-1214-EL-AAM), on recovery of transition costs and calculation of the market value of generation assets. Joint testimony (with Dr. Scott T. Jones), December 22, 1999; supplemental testimony (with Dr. Scott T. Jones), April 4, 2000; deposition, April 7, 2000.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-10*, in support of an application to construct a 540 MW gas-fired single cycle peaking power plant in Medway, Massachusetts. Prepared direct testimony, April 1999; oral testimony under cross-examination, July 27, 1999.

- **Village of Bergen, et al.**
  Before the *Supreme Court of the State of New York, Index No. 081556*, Affidavit in Response to Defendant's Submission of February 25, 1999, in *Village of Bergen, et al., Plaintiffs, v. Power Authority of the State of New York, Defendant*, March 3, 1999.

  Before the *Supreme Court of the State of New York, Index No. 081556*, Affidavit in Support of Petition to Correct Rates, in *Village of Bergen, et al., Plaintiffs, v. Power Authority of the State of New York, Defendant*, October 17, 1996.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-7*, in support of an application to construct a 750 MW gas-fired combined cycle power plant at the Fore River Station in Weymouth, Massachusetts (Edgar). Prepared direct testimony, February 10, 1999; oral testimony under cross-examination, July 26, 1999.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-8*, in support of an application to construct a 1500 MW gas-fired combined cycle power plant at the Mystic Station in Everett, Massachusetts. Prepared direct testimony, February 10, 1999; oral testimony under cross-examination, May 25, June 2, 1999.

- **U.S. Generating Company**
  Before the *Connecticut Siting Board, Docket No. 189*, on an application to construct a new Lake Road Generating Project, September 1998. Oral testimony under cross-examination .

- **Central Hudson Gas & Electric Corporation**
  Before the *Supreme Court of New York, Index No. 255/1998, CHGE v. West Delaware Hydro Associates*, on issues relating to ratemaking treatment of costs relating to power contracts, April 13, 1998.

- **Sithe New England Holdings, LLC**
  Before the *Massachusetts Department of Telecommunications and Energy and the Massachusetts Energy Facilities Siting Board, Docket Nos. DTE98-84 and EFSB98-5*, on issues pertinent to forecast and supply planning by electric companies, September 14, 1998.

- **Sithe Energies, Inc.**
  Before the *Massachusetts Energy Facilities Siting Board, Docket No. EFSB98-3*, on issues related to the agency's rulemaking establishing a Technology Performance Standard, June 8, 1998.

  Before the *Massachusetts Energy Facilities Siting Board, Docket No. EFSB98-1*, on issues related to the agency's review of project viability as part of its review of power plant applications, March 16, 1998.

- **Pennsylvania Power & Light**
  Rebuttal testimony on codes of conduct governing affiliate relations. *Pennsylvania Public Utility Commission, Docket Nos. A-122050F0003, A-120650F0006*, testimony under cross-examination, February 17, 1998.

  Rebuttal testimony on rate unbundling and rate design issues, on consumer protection issues. *Pennsylvania Public Utility Commission, Docket No. R-00973954*, testimony under cross-examination, August 5, 1997.

  Before the *Pennsylvania Public Utility Commission, Docket No. R-00973954*, on rate design, April 1, 1997.

- **Nextel Communications**
  Before the *Massachusetts Department of Public Utilities, Docket 95-59-B*, on telecommunications facility matters, testimony under cross-examination, January 1997.

- **Arizona Public Service Company**
  Before the *Arizona Corporation Commission, Docket No. U-0000-95-506*, on integrated resource planning and competition, October 1996.

- **U.S. Generating Company**
  Before the *Massachusetts Energy Facilities Siting Board, Docket 96-4,* on an application to construct a new Millennium power generating facility, testimony under cross-examination, October 1996.

- **MCI Communications, Inc.**
  Before the *Massachusetts Department of Public Utilities*, in the NYNEX interconnection docket. Opening up the Local Exchange Market to Competition: Common Themes with Retail Competition in Electricity and Natural Gas Industries, August 30, 1996.

- **Intercontinental Energy Corporation**
  Before the *New Jersey Board of Public Utilities, No. EX94120585Y,* on the Energy Master Plan Phase I Proceeding to Investigate the Future Structure of the Electric Power Industry, July 1996.

  Before the *Massachusetts Department of Public Utilities, DPU 96-100,* on the Investigation Commencing a Notice of Inquiry/Rulemaking for Electric Industry Restructuring Proceedings, July 1996.

- **Several confidential expert reports, testimonies, and depositions in confidential arbitrations and mediations.**

PUBLICATIONS, REPORTS, ARTICLES

"Comments of Susan F. Tierney and Paul. J. Hibbard on their own behalf," before the *Federal Energy Regulatory Commission, in the Matters of Solicitation Processes for Public Utilities (Docket No. PL04-6-000) and Acquisition and Disposition of Merchant Generation Assets by Public Utilities (Docket No. PL04-9-000),* on the role of independent monitors and independent evaluators in public utility resource solicitations, July 1, 2004.

"Energy and Environmental Policy in the United States: Synergies and Challenges in the Electric Industry" (with Paul J. Hibbard), prepared for Le Centre Français sur les Etats-Unis (The French Center on the United States), July 2003; presentation in Paris, October, 2003.

"Supplemental Report on the Benefits of New Gas Infrastructure in New England: The Everett Extension Project" (with Charles Augustine), prepared for Algonquin Gas Transmission Company, February 5, 2003.

"The Political Economy of Long-Term Generation Adequacy: Why an ICAP Mechanism Is Needed as Part of Standard Market Design" (with Janet Gail Besser and John Farr), *The Electricity Journal,* August/September 2002.

"Siting Power Plants in the New Electric Industry Structure: Lessons California and Best Practices for Other States" (with Paul J. Hibbard), *The Electricity Journal*, June 2002.

"Siting Power Plants: Recent Experience in California and Best Practices in Other States" (with Paul J. Hibbard), prepared for The Hewlett Foundation and The Energy Foundation, February 2002.

"Economic and Environmental Benefits of the Kings Park Energy Project: System Production Modeling Report" (with Joseph Cavicchi), prepared for PPL Global, January 25, 2002.

"The Benefits of New Gas Infrastructure in New England: The Maritimes & Northeast Phase IV Pipeline Project" (with Charles Augustine), prepared for Maritimes & Northeast Pipeline, LLC, January 2002.

"Activating Ontario's Capacity Market: Design and Implementation Issues" (with Janet Gail Besser and John Farr), prepared for Sithe Energies, Inc., October 24, 2001.

White paper on "Ensuring Sufficient Capacity Reserves in Today's Energy Markets" (with Janet Gail Besser and John Farr), prepared for submission as part of comments filed by Sithe Power Marketing LLC, Sithe New England Holdings, and FPL Energy LLC, in FERC Docket No. EX01-1-000, October 17, 2001.

"The Rationale and Need for Capacity Obligations and a Capacity Market in a Restructured Ontario Electricity Industry" (with Janet Gail Besser and John Farr), prepared for Sithe Energies, Inc., September 27, 2001.

"Economic and Environmental Benefits of the Wawayanda Energy Center: System Production Modeling Report" (with Joseph Cavicchi), prepared for Wawayanda Energy Center, LLC, August 24, 2001.

"A Better CO_2 Rule," op-ed, *The New York Times*, May 16, 2001.

"Air Pollution Reductions Resulting from the Kings Park Energy Project" (with Joseph Cavicchi), prepared for PPL Global, January 24, 2001.

"Report on "Economic Benefits of Wireless Telecommunications," prepared on behalf of the New Hampshire Coalition of Wireless Carriers for the New Hampshire HB 733 Study Committee, November 13, 2000.

Expert Report: "Public Benefits of the Proposed Cross Sound Cable Project Prepared for TransÉnergie U.S. Ltd.," July 2000.

"The Benefits of New Gas Infrastructure in Massachusetts and New England: The Maritimes & Northeast Phase III Pipeline and the Algonquin Gas Transmission Company HubLine Projects" (with Wayne Oliver of Navigant Consulting), prepared for Maritimes & Northeast Pipeline, LLC and Algonquin Gas Transmission Company, October 2000.

"Production Modeling for the Astoria Project: Report on Results" (with John G. Farr), report for SCS Energy Corp., June 14, 2000.

"Observations from Across the Border: Implications for Canadian Reliability of Recent Changes in U.S. Electricity Markets and Policy," white paper for Natural Resources Canada, 1999.

"Research Support for the Power Industry" (with M. Granger Morgan), *Issues in Science and Technology,* Fall 1998.

"Maintaining Reliability in a Competitive U.S. Electricity Industry," Final Report of the Task Force on Electric System Reliability, U.S. Department of Energy, September 29, 1998.

"Regional Issues in Restructuring the Electric Industry," *The Electricity Industry Briefing Papers*, The National Council on Competition and the Electric Industry, April 1998.

"Fueling the Future: America's Automotive Alternatives" (with Philip Sharp), The American Assembly, Columbia University, Arden House, NY, September, 1995.

"Needed: Broad Perspective, Fresh Ideas," guest editorial, *The Electricity Journal*, November 1994.

Foreword in J. Raab, *Using Consensus Building to Improve Utility Regulation*, American Council for an Energy-Efficient Economy, Washington, DC, 1994

"Massachusetts' Pre-Approval Approach to Prudence in Massachusetts," *The Electricity Journal*, December 1990.

"Using Existing Tools to Pry Open Transmission—A New England Proposal," *The Electricity Journal*, April 1990.

"Sustainable Energy Strategy: Clean and Secure Energy for a Competitive Economy" (directed), National Energy Policy Plan, July 1995.

"The Domestic Natural Gas and Oil Initiative: First Annual Progress Report" (directed), U.S. Department of Energy, February 1995.

General Guidelines for Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992 (directed), U.S. Department of Energy, October 1994.

"Fueling a Competitive Economy: Strategic Plan for the U.S. Department of Energy" (directed), April 1994.

"The Domestic Natural Gas and Oil Initiative: Energy Leadership in the World Economy" (directed), U.S. Department of Energy, December 1993.

"Siting Needs: Issues and Options," U.S. Department of Energy, June 1993.

"The Nuclear Waste Controversy," in D. Nelkin, *Controversy: The Politics of Technical Decisions*, Sage, 1977; 1984 (second edition).

DATAWARS: Computer Models in the Federal Government (with Kenneth L. Kraemer, Siegfried Dickhoven, and John Leslie King), Columbia University Press, 1987.

"The Evolution of the Nuclear Debate: The Role of Public Participation," *Annual Review of Energy*, 1978.

OTHER PROFESSIONAL ACTIVITIES

Chair, Ocean Management Task Force to the Massachusetts Secretary of Environmental Affairs, 2003-2004.

Member, National Commission on Energy Policy, 2002 to present

Member, Board of Directors, Catalytica Energy Systems Inc., 2001 to present

Co-Chair, RTO Futures: Regional Power Working Group, 2001-2002

Member, Advisory Committee, Carnegie Mellon Electricity Industry Center, 2001 to present

Member, Board of Directors, Climate Policy Center (formerly, Americans for Equitable Climate Solutions (SkyTrust)), 2001 to present

Chair, Board of Directors, Electricity Innovations Institute, 2002 to present; Director, 2001 to present

Member, Florida Energy 2020 Study Commission, Environmental Technical Advisory Committee, 2001

Chair of the Board of Directors, The Energy Foundation, 2000 to present; Vice-Chair, 1999-2000; Director, 1997 to present

Chair, Board of Directors, Clean Air–Cool Planet: A Northeast Alliance, 1999 to present

Member, Policy Advisory Committee, China Sustainable Energy Project–A Joint Project of The Packard Foundation and The Energy Foundation, 1999 to present

Director, North East States Center for a Clean Air Future (formerly, Northeast States Clean Air Foundation), 1998 to present

Director, Electric Power Research Institute, 1998 to 2003

Technical Advisor, Mid-Atlantic Area Council/PJM, Dispute Resolution Procedure, 1998 to present

Member, "ISO-New England" (Independent System Operator) Advisory Committee, 1998 to 2003

Director, The Randers Group (subsidiary of Thermo TERRATEK), 1997 - 2000

Director, MHI, Inc. (electric utility aggregator for non-profit organizations in Massachusetts), 1997 - 1999

Director, Thermo ECOTEK Corporation, 1996 - 1999

Member, United States Department of Energy, Electricity Reliability Task Force, 1996-1998

Member, Harvard Electricity Policy Group, 1993 to present

HONORS AND AWARDS

Distinguished Alumna Award, Scripps College, Claremont, CA, 1998

Award for Individual Leadership in Public Service, *The Energy Daily*, 1995

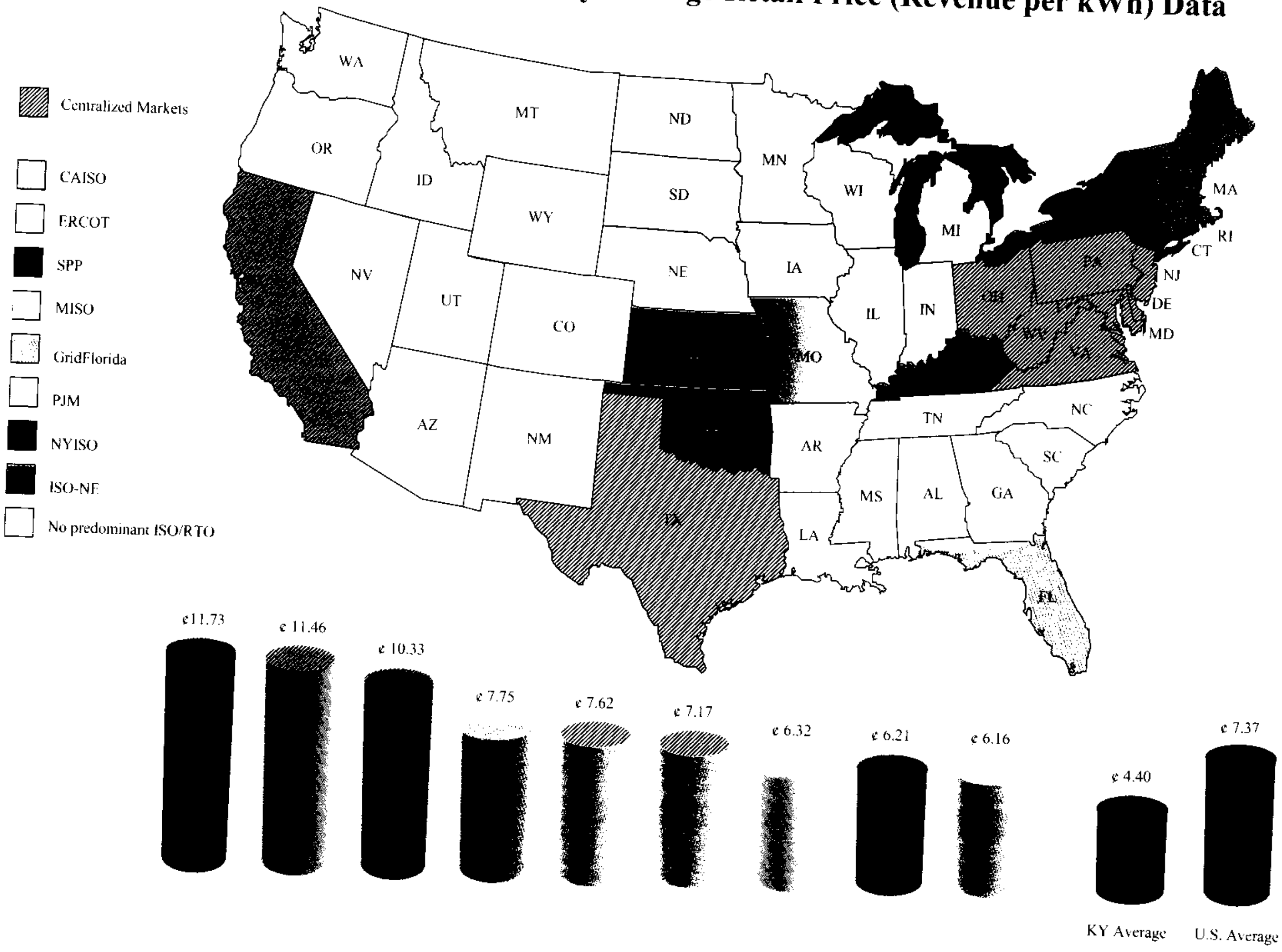
Special Recognition Award for Outstanding Contribution to the Industry, Cogeneration and Competitive Power Institute, Association of Energy Engineers, 1994

Leadership Award, National Association of State Energy Officials, 1994

Commencement Speaker and Honorary Doctorate of Laws, Regis College, Weston, MA, 1992.

Attachment B

2003 U.S. Electric Utility Average Retail Price (Revenue per kWh) Data



Sources and Notes for Attachment B

Source:

EIA, *Historical 1990 through Current Month Retail Sales, Revenues, and Average Retail Price of Electricity by State and by Sector.*
http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

Notes:

1. Map data reflects weighted averages per region of dollar revenue in all customer sectors divided by megawatt hour sales in all sectors.

2. Certain states have areas that are serviced by one or more ISO/RTOs; in these cases we have included them in the ISO/RTO that oversees the greatest area. Exceptions are noted below.

3. Missouri is serviced by both SPP and MISO, and is included in the average calculations for both regions.

4. Kentucky is isolated in the map and average calculations for illustrative purposes.

5. Illinois is serviced by both MISO and PJM. However, since 70% of the population is associated with a utility that is part of PJM, the state has been included in the average calculation for PJM.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

SEP 2 9 2004

PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	)))))	CASE NO. 2003-00266

SUPPLEMENTAL TESTIMONY OF MARK S. JOHNSON DIRECTOR, TRANSMISSION LG&E ENERGY LLC

Filed: September 29, 2004

Q. Please state your name, position and business address.

A. My name is Mark S. Johnson. I hold the position of Director of Transmission for LG&E Energy LLC ("LG&E Energy"), the parent company of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, P.O. Box 32020, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. I received my Bachelor of Science degree in Civil Engineering Technology from Murray State University in 1980. I have 23 years of experience in the utility industry. From May 1980 to January 1985, I was employed by the Tennessee Valley Authority at the Watts Bar Nuclear Generating Station, where I held the position of Manager, Document Control and Configuration Management. From January 1985 to February 1987, I was employed by Entergy at the Grand Gulf Nuclear Generation Station as Manager, Engineering Support. From February 1987 to November 1997, I was again employed by the Tennessee Valley Authority, where I held a number of senior level positions in power generation, transmission, customer service and marketing. Most notably, I was Area Vice President, Transmission, Customer Service and Marketing for three and one-half years. Then, in November 1997, I joined LG&E Energy as Director, Distribution Operations. I remained in that position until January 2001, when I assumed my current position.

Q. Have you previously testified before this Commission?

A. Yes. I filed rebuttal testimony in this proceeding on February 9, 2004. I also filed testimony on November 12, 2003 in *In the Matter of: An Investigation of the Proposed*

Construction of 138 kv Transmission Facilities in Mason and Fleming Counties by East Kentucky Power Cooperative, Inc., Case No. 2003-00380.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss whether there are impediments to joining another Regional Transmission Organization ("RTO") other than the Midwest Independent Transmission System Operator ("MISO"), and to update the Commission on new information I have learned since the hearing in February, 2004.

Q. If LG&E/KU were to withdraw from MISO, would you still expect to enter into a reliability coordination agreement with another entity?

A. Yes. Under such an agreement, we would expect to receive the typical reliability coordination functions, including outage coordination service.

Q. Would an exit from MISO result in a reduction in reliability for LG&E/KU?

A. Absolutely not. Because the power system is highly integrated, all entities that are responsible for the planning, operation, and use of the bulk electric system are required to comply with North American Electric Reliability Council ("NERC") reliability standards. As a result, from a reliability standpoint, coordination service should be the same regardless of whether it is provided by MISO or any other NERC certified Reliability Coordinator.

Q. Have you investigated the availability and cost of reliability coordination service should LG&E/KU be allowed to operate their own transmission system outside of a RTO?

A. Yes. We have had general discussions with TVA about their provision of reliability coordination services. Currently, TVA provides such services to Big Rivers Electric

Corporation and East Kentucky Power Cooperative in Kentucky. Based on TVA's experience with reliability coordination service provided to Associated Electric Cooperative Inc. (which has load characteristics similar to LG&E/KU), reliability coordination services could be provided for approximately $250,000 per year and tariff administration could be provided for approximately $150,000 per year, compared to $6,000,000 for reliability coordination and tariff administration services as provided by MISO.

Q. If LG&E/KU decide to join an RTO other than the MISO, would a physical interconnection be necessary?

A. Based on discussions we have had with Southwest Power Pool ("SPP"), a firm contract path or physical connection would not be required for membership in SPP. There is no reason why a physical interconnection is required to receive reliability coordination services so long as the Reliability Authority maintains a view of the system.

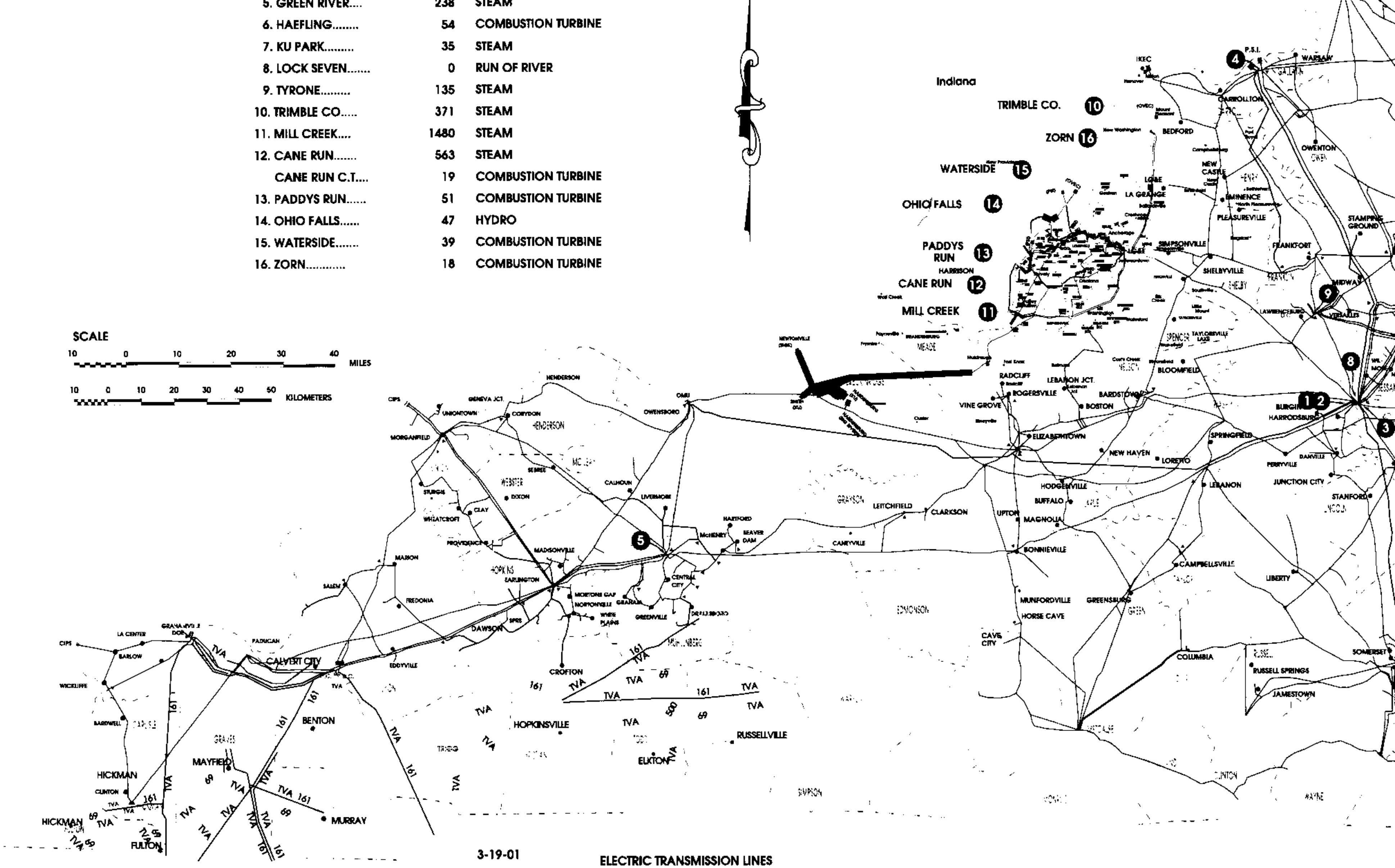
Q. Do LG&E/KU have a physical connection to any RTO other than the MISO?

A. Yes. Because the Companies are physically connected to American Electric Power ("AEP"), LG&E/KU will have a physical interconnection to PJM Interconnection, LLC ("PJM") when AEP officially becomes a member of PJM on October 1, 2004. A map showing all of the Companies' physical interconnections with MISO, PJM and other regional transmission companies is contained in Exhibit MSJ-1.

Q. Does this conclude your testimony?

A. Yes, it does.

5. GREEN RIVER....	238	STEAM
6. HAEFLING........	54	COMBUSTION TURBINE
7. KU PARK.........	35	STEAM
8. LOCK SEVEN.......	0	RUN OF RIVER
9. TYRONE.........	135	STEAM
10. TRIMBLE CO.....	371	STEAM
11. MILL CREEK....	1480	STEAM
12. CANE RUN.......	563	STEAM
CANE RUN C.T....	19	COMBUSTION TURBINE
13. PADDYS RUN......	51	COMBUSTION TURBINE
14. OHIO FALLS......	47	HYDRO
15. WATERSIDE.......	39	COMBUSTION TURBINE
16. ZORN...........	18	COMBUSTION TURBINE



3-19-01

ELECTRIC TRANSMISSION LINES

69,000 VOLTS........................

138,000 VOLTS........................

161,000 VOLTS........................

345,000 VOLTS........................

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

SEP 2 9 2004

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	)))))	CASE NO. 2003-00266

SUPPLEMENTAL TESTIMONY OF
MARTYN GALLUS
SENIOR VICE PRESIDENT, ENERGY MARKETING
LG&E ENERGY LLC

Filed: September 29, 2004

Q. Please state your name, position and business address.

A. My name is Martyn Gallus. I am the Senior Vice President of Energy Marketing for LG&E Energy LLC ("LG&E Energy"), the parent company of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU" or "the Companies"). My business address is 220 West Main Street, P.O. Box 32020, Louisville, Kentucky 40202.

Q. Please provide a description of your educational and professional background.

A. A description of my education and professional background is set forth in Appendix A to my testimony.

Q. Have you previously testified before this Commission?

A. Yes. I previously testified in this investigation at the hearing on February 22, 2004. I have also testified in proceedings involving the method of regulation of the Companies and three certificate and convenience and necessity cases involving the resource acquisitions of the Companies.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Companies' efforts to assess the potential costs and benefits from off-system sales volumes and margins in the Midwest Independent Transmission System Operator, Inc.'s ("MISO") Energy Markets Tariff ("EMT," which creates the "Day 2 markets"), discuss whether exiting MISO will impact the Companies' ability to make off-system sales ("OSS") and the margins thereon, and how the Day 2 markets' use of Locational Marginal Prices ("LMPs") and Financial Transmission Rights ("FTRs") will impact the Companies' trading and risk management activities.

Companies' Analysis of Sales Volumes and Margins

Q. Please provide a general description of the Companies' analysis of the off-system sales margins and volumes that can be reasonably expected by LG&E/KU under the terms of the MISO's Day 2 market.

A. MISO's Chief Executive Officer, James Torgerson, recently stated that MISO's primary rationales for the EMT are to "better manage congestion on the grid and produce consumer savings through the centralized dispatch of generation throughout the region."[1] Under my direction and supervision, the Companies undertook an analysis to calculate the economic impacts of such a centralized dispatch system on their operations. The analysis included evaluating electricity prices under differing assumptions regarding the Companies' participation in an RTO and calculating the Companies' cost to serve native load and off-system sales margins under alternative RTO and non-RTO assumptions. This analysis is contained in Appendix B to my testimony and was provided to Mr. Morey for his consideration in connection with his cost-benefit analysis.

Q. Please describe the software packages that were used to perform the analysis.

A. Three software packages were used to perform this analysis. MIDAS Gold ("MIDAS") was used to generate the electricity price forecasts. PROSYM was used to evaluate the Companies' cost to serve native load and off-system sales margin production cost revenue requirements. MUST was used in the calculation of transfer limits used in both MIDAS and PROSYM. MUST is an industry-accepted tool for the calculation of transfer limits and is used in the NERC Interchange Distribution Calculator. Appendix B to my testimony provides a detailed description of the software, sources of data, and assumptions concerning transfer capabilities and hurdle rates used in the analysis.

Q. What were the results of the analysis?

A. The detailed results of the analysis are shown in Exhibit MG-1 attached to my testimony. These results, which are summarized below, include only the energy cost to serve native load and the costs of, and revenues from, off-system sales. This analysis does not include all of the costs and revenues included in Mr. Morey's cost-benefit analysis, such as RTO administrative costs and transmission revenues.

Table 1
Total Energy Cost to Serve Native Load, Net of OSS Revenues and Costs

2004 NPV ($millions)	RTO (MISO/PJM)	TORC[2] Low Transfer Capability	TORC	TORC High Transfer Capability
Total Native Load Energy Costs	3,692	3,689	3,691	3,692
Off-System Sales Net Revenue	(238)	(205)	(230)	(240)
Total Costs (Net of Revenue)	3,455	3,484	3,462	3,452

In sum, our analysis shows that being in MISO will have a small positive impact on the Companies' costs net of OSS revenue, even under MISO's assumption that Day 2 markets will increase the Companies' ability to increase OSS significantly. Our analysis also shows that this benefit is *less* than the Companies' MISO Day 2 market schedule costs (Schedules 16 and 17), resulting in a net loss to the Companies for participating in

[1] MISO Press Release, *FERC Approves Midwest ISO Energy Markets Tariff*, August 9, 2004 at 1.

the Day 2 markets during the study period. The Companies' Day 2 market participation net loss grows larger as one moves away from MISO's result-driven assumption about how many additional MWh the Companies feasibly could produce for OSS, as well as MISO's assumption that the Companies would face relatively severe transmission constraints in Transmission Operator with Reliability Coordinator (TORC) operation.[3]

Q. Is it reasonable to expect that the Companies can significantly increase their off-system sales volumes when operating under MISO's EMT in order to maintain or increase the current level of net revenues from off-system sales?

A. No. MISO has stated that prices for wholesale power will decline in Day 2. Therefore, unless the Companies can reduce the costs of producing power, which is unlikely because the Companies are among the lowest-cost power producers in the nation, the margins the Companies realize on off-system sales will decrease in Day 2. MISO has asserted that the Companies will not experience reduced net revenues from OSS, however, because the Companies will be able to sell an increased volume of power into the wholesale market because MISO's Day 2 will (1) make the transmission system more efficient, making possible trades that could not otherwise take place, and (2) make the markets more transparent, thus allowing trades to take place that would not have otherwise due to lack of information. However, as the chart above shows, the Companies net revenues from OSS will remain about the same whether or not they are MISO members. Therefore, the Companies can expect a net loss from their participation in the Day 2 markets once MISO's administrative costs are taken into account, as Mr. Morey shows in his testimony and cost-benefit analysis.

[2] TORC stands for Transmission Operator with Reliability Coordinator, meaning a situation in which the Companies operate their own transmission system, but with a third-party reliability coordinator.

According to MISO, the decline in OSS margins due to lower prices will be more than offset by the transmission system efficiencies and market transparency that Day 2 will create. Yet MISO's assertion will be difficult, if not impossible, to observe in the real world. The Companies' analysis shows that their RTO membership status will have almost no impact on electricity prices; in other words, if MISO Day 2 truly will bring down wholesale prices, it will do so regardless of whether or not the Companies are MISO members. Because the Companies' RTO membership status will not affect electricity prices, only the Companies' ability to utilize the transmission system should affect the quantity of OSS the Companies will make in a Day 2 world. As I noted above, MISO has claimed that it will increase the Companies' ability to use the transmission system, which, MISO claims, will lead to increased OSS. Yet the information I present in the tables below demonstrates that the Companies' generating units are expected to operate at high capacity factors regardless of whether or not the Companies belong to MISO. Furthermore, if the Companies do not acquire significant new baseload generation capacity, then as native load grows the Companies will have less energy available to sell off-system.

Q. Are there any differences in the capacity factors of the Companies' generating plants between the MISO case and the TORC case?

A. No. The results of the Companies' MIDAS analysis show that there is virtually no difference in the forecasted wholesale electricity prices between the MISO and TORC cases because the Companies' RTO membership status will not materially impact wholesale electricity prices. Therefore, the reason the Companies' generating units dispatch differently results almost entirely from the lower transfer capability resulting

[3] See note 2 above.

from TLRs assumed by MISO in the TORC case. As the information in Table 2 below demonstrates, in spite of the lower transfer capability in the TORC case, the average capacity factors are identical to the MISO case except for one unit.

Table 2
Average Unit Capacity Factors
Forecasts are for 2005 to 2010

Units	In MISO	TORC Transmission Sensitivity
Brown 1	56%	56%
Brown 2	80%	80%
Brown 3	71%	71%
Ghent 1	85%	85%
Ghent 2	78%	78%
Ghent 3	83%	83%
Ghent 4	80%	80%
Green River 3	40%	41%
Green River 4	54%	54%
Tyrone 3	43%	43%
Smith 1	77%	77%
Smith 2	77%	77%
Cane Run 4	75%	75%
Cane Run 5	68%	68%
Cane Run 6	75%	75%
Mill Creek 1	74%	74%
Mill Creek 2	75%	75%
Mill Creek 3	78%	78%
Mill Creek 4	76%	76%
Trimble 1	88%	88%

Q. **Are there any differences in the volumes of off-system sales and purchases between the MISO case and the TORC case?**

A. Off-system sales volumes are forecasted to be slightly higher in the MISO case compared to the TORC case. The increased transfer capability assumed to result from the use of LMPs to manage congestion instead of TLRs results in slightly more volume being sold than in the TORC case. Table 3 shows that the Companies sell in most years around 20 GWh (0.5 percent) more in the MISO case than in the TORC case.

Table 3
Difference in Combined Company Off-system Sales
MISO less TORC
(GWh)

	On Peak 7x16	Off Peak 7x8	Total(*)
2005	55	6	62
2006	18	0	18
2007	12	6	18
2008	3	10	14
2009	8	12	20
2010	14	9	23

(*) Totals may not add due to rounding.

Similarly, Table 4 shows that the impact of increased transfer capability in the MISO case allows market purchases to increase relative to the TORC case. The biggest impact of the MISO case relative to the TORC case occurs in the potential for the Companies to purchase off-peak energy during certain years. This is due to the increase in transfer capability and lack of a hurdle rate to purchase energy from other MISO members.

Table 4
Difference in Combined Company Off-system Purchases
MISO less TORC
(GWH)

	On Peak 7x16	Off Peak 7x8	Total(*)
2005	2	2	5
2006	13	73	86
2007	27	83	110
2008	28	94	122
2009	48	22	69
2010	22	3	25

(*) Totals may not add due to rounding.

Q. How do the volumes of off-system sales and purchases for each of these cases compare to the Company's historical experience?

A. Table 5 shows that the forecasted sales volumes for each case are consistent with recent experience. The 2005 sales volumes are somewhat higher than other years' because the Companies will enjoy existing coal contracts with prices below current spot prices through 2005, which the Companies factored into their PROSYM modeling. This results in the Companies' units having a cost advantage against the rest of the market. This advantage is unlikely to be realized as other companies likely will have older, lower-cost coal contracts as well. For off-system sales, the largest volume differences between the model cases and historical experience occur in the off-peak hours. Given the large concentration of coal-fired generation in the Midwest, it can often be difficult to move all of the volume that the Companies have economically available during some off-peak periods. Furthermore, these volumes often have extremely low margins.

Because the Companies have low-cost generating resources, they serve approximately 99 percent of their native load with their own generation both historically and in the PROSYM analysis. Therefore, the forecasted market purchases shown in

Table 6 are in line with historical experiences.

Table 5
Combined Company Off-system Sales
(GWH)

	In MISO			TORC		
	On Peak 7x16	Off Peak 7x8	Total(*)	On Peak 7x16	Off Peak 7x8	Total(*)
2000	4,102	1,836	5,938	4,102	1,836	5,938
2001	4,171	1,855	6,026	4,171	1,855	6,026
2002	2,880	874	3,754	2,880	874	3,754
2003	3,479	902	4,381	3,479	902	4,381
2005	3,870	2,431	6,302	3,815	2,425	6,240
2006	3,437	1,538	4,975	3,419	1,538	4,957
2007	2,745	1,269	4,014	2,733	1,263	3,996
2008	2,631	1,511	4,143	2,628	1,501	4,129
2009	2,135	1,929	4,064	2,127	1,917	4,044
2010	2,323	2,093	4,416	2,309	2,084	4,393

(*) Totals may not add due to rounding.

Table 6
Combined Company Off-system Purchases
(GWH)

	In MISO			TORC		
	On Peak 7x16	Off Peak 7x8	Total(*)	On Peak 7x16	Off Peak 7x8	Total(*)
2000	943	116	1059	943	116	1059
2001	781	224	1005	781	224	1005
2002	572	25	597	572	25	597
2003	281	15	297	281	15	297
2005	338	12	351	336	10	346
2006	343	86	429	330	13	343
2007	472	125	597	445	42	487
2008	665	181	846	637	87	724
2009	806	89	894	758	67	825
2010	672	79	751	650	76	726

(*) Totals may not add due to rounding.

Impact on Companies' Trading and Overall Business

Q. Please explain the impact of LMPs and FTRs on the Companies' risk management activities.

A. There are three clear impacts that the Day 2 markets will have on the Companies' risk management activities, two of which directly result from the Day 2 markets' use of LMPs and FTRs. The first is that the Companies will have to incur significant costs to prepare to participate in the Day 2 markets. For example, the Companies have already contracted for or otherwise allocated approximately $1 million for Day 2 market trading implementation, including hardware and software upgrades, as well as outside consulting and in-house IT man-hours. The Companies also expect to spend $950,000 for Day 2 market trading support tools, such as LMP market simulation software, to help the Companies' traders make the best business decisions in the new markets. Finally, additional headcount will likely be required to effectively operate in the Day 2 market. Again, these costs are *not* included in the Companies' analysis above, which shows only small benefits for the Companies in the Day 2 markets under the most generous assumptions to MISO -- benefits that are dwarfed by the costs attributable to them.

The second clear impact that the Day 2 markets will have on the Companies' trading and risk management activities is that the new markets' use of LMPs and FTRs will subject the Companies to substantial risks they do not now face. As Mr. Morey showed in his previous testimony in this proceeding, the Companies face the possibility of significant financial loss if they under- or over-hedge against congestion costs with FTRs. It is extremely unlikely that the Companies will hedge perfectly. At this point, these markets exist only in theory; it follows that the Companies have no practical experience to draw upon to make the best business decisions therein. Furthermore, there is no escaping the simple fact that FTRs are an imperfect hedge against congestion. There is no guarantee that the Companies will be able to obtain all the FTRs they seek in the FTR nomination process because all allocated FTRs must be simultaneously feasible. As entities nominate candidate FTRs, MISO models each nominated FTR as a transaction for that volume between the nominated FTR's identified source and sink. MISO's Simultaneous Feasibility Test ("SFT") ensures that the combined impact of all simulated FTR-defined transactions do not exceed the capacity of MISO's transmission system. In addition to FTRs the Companies request, they may be allocated FTRs that are uneconomic in order to allow other entities to receive FTRs. MISO will assign these "counter-flow" FTRs to the Companies in order to make more FTRs simultaneously feasible for others. Moreover, because a fixed and constant volume of FTRs are nominated once each season (three months) while the Companies' load changes daily, it is unlikely that the Companies will possess the ideal number of FTRs on the right transmission paths on any given day. Again, given the very small benefit that the Day 2 markets promise under the best circumstances (and only when one ignores the Schedule 16 and 17 costs, as well as the costs to prepare for the Companies' participation in the Day 2 markets), it is not worth incurring the additional risk that the LMP and FTR systems pose.

Finally, the Day 2 markets will affect the manner in which the Companies will be able to call upon its own generation resources and its contracted generation resources, OMU, OVEC and EEI. OMU will become a Designated Network Resource ("DNR") under the EMT; it appears likely that OVEC and EEI will as well. Thus, low-cost resources that the Companies have built or contracted to provide power for their native load will instead either be dispatched by MISO or self-scheduled, which, as I describe further below, still presents the possibility of additional costs the Companies do not now face.

Q. Will self-scheduling of their resources allow the Companies to avoid impacts of the MISO Day 2 market?

A. No, notwithstanding that FERC suggests the Companies can do just that in paragraph 573 of their August 6, 2004 order, which states, "Therefore, LG&E has the option of designating all its generation resources as self-scheduled and thereby serve all retail native load with its own generation in the same way this would occur without an ISO energy market." Although self-scheduling will allow the Companies to ensure that MISO dispatches the Companies' generation, Day 2 self-scheduling will not produce the same *economic* result as the Companies now produce for their ratepayers. The output of a self-scheduled resource is settled in the same manner as the output of a generation resource that has made an "offer" to MISO and is subsequently dispatched. In both cases the resource receives the hourly LMP at its respective Commercial Node. The result is that the Companies will pay congestion costs between their generating units and their load zones regardless of whether or not their resources are self-scheduled. Thus, there is no way for the Companies to avoid being economically impacted by the Day 2 market.

Self-scheduling may also, in fact, be detrimental to overall market efficiency. Because the output of a self-scheduled resource impacts MISO's calculation of optimal LMPs, changing a resource's output from the MISO-calculated optimum will not only alter the LMP at the self-scheduled resource, but will also cause all LMPs throughout the footprint to be sub-optimal.

Because the Companies will be responsible for congestion between all their resources and load, they will be impacted financially by self-scheduling, just as they will be impacted by offering their generation into the Day 2 markets with price-sensitive offers.

Q. Please explain how Day 2 will impact the Companies' dispatch of their generating facilities to serve Kentucky retail ratepayers.

A. In Day 2, the Companies will be required to make their generating facilities available to MISO under the FERC-approved EMT. Under the EMT, the Companies must become "Market Participants" by making their generation facilities available to the MISO "pool" even if they wish to use their generation resources solely to self-serve their native load customers in Kentucky. Overruling the Companies' objection to this requirement, FERC's August 6, 2004 Order asserted that under the EMT, "load-serving entities ["LSEs"] may fully use their DNRs [generation resources, or Designated Network Resources] to satisfy their must-offer obligations through self-schedules and therefore can ensure that their DNRs are used to serve their respective customers. . ." (August 6, 2004 Order, ¶412). However, EMT Section 69.2 offers the Companies only two options:

1. Self-schedule the Companies' generating units; or

2. Offer them in the day-ahead energy market and the Reliability Assessment Commitment ("RAC") short-term capacity market.

This mandatory requirement, in addition to MISO's control over interruptible load, degrades the Companies' authority over their own integrated resources necessary to fulfill their obligation to serve their native load. As of today, excess generating resources are available to provide energy to the real-time market at competitive prices only after LSEs, like the Companies, have first fulfilled their state obligations to serve.

In addition to the operational constraints the MISO EMT imposes on the Companies' generation scheduling, the EMT's requirement that all generating facilities be "regionalized" poses a potentially significant financial impact on the Companies and their customers. To the extent that MISO schedules LG&E/KU-owned generation to serve non-LG&E/KU load in the day-ahead market, the Companies must purchase "pool" resources in real-time at marginal prices established in the wholesale power market. Such market prices may be significantly higher than cost of production from the Companies' own generating facilities, which are always subject to dispatch by MISO. Prior to Day 2 implementation these facilities would have been available in real-time to serve native load at marginal cost for those facilities absent MISO's "call" on such resources through the EMT. Contrary to MISO's assertion,[4] the Companies' native load pays average cost-based rates for energy supplied by the Companies' generating facilities. Approximately 99% of native load energy consumption is supplied from facilities currently controlled by the Companies. Whenever the Companies' generating facilities not used to serve native load have a marginal cost below the Day 2 day-ahead market LMP, MISO will require the Companies to sell that capacity to the Day 2 market. Thus, that generation will not be available to meet the inevitable fluctuations in the Companies' real-time load and generation. Instead, the Companies will have to purchase energy at real-time market prices that, in all likelihood, will be greater than the cost the

[4] In response to LG&E/KU data request no. 54, MISO asserts that 100% of the load within MISO pays market clearing price today and will pay that same price level for energy in Day 2.

Companies would have incurred if they could have used their own low-cost generation. This greater cost will result in financial harm to the Companies' native load customers.

Q. Please explain the overall functioning of the Day 2 markets' settlement process.

A. The Day 2 markets consist of two settlement systems; a day-ahead settlement and a real-time settlement. Real-time settlements, in the most basic terms, reflect the costs and revenues associated with deviations between what actually transpires and is registered by meters, and those market participant schedules that have cleared, or were approved as economic by MISO, on the day prior to operating day.

MISO's settlement system remains a work in progress; however, it promises to add considerable complexity and risk to the Companies' accounting of self-generated energy to serve native load customers. The Companies anticipate having to make additional investments in personnel and systems to ensure that MISO's settlements and numerous resettlements over a 3-4 month period are and remain accurate.

Q. Will self-scheduling allow the Companies to mitigate the potential adverse impacts of the Day 2 markets?

A. In the proposed Day 2 markets, if the Companies were to self-schedule available generation in an amount intended to meet their forecasted native load, the Companies alone would be responsible for any commitment costs -- start-up and no-load costs, which Mr. Beer defines in his testimony -- associated with their self-scheduled resources. The Companies would also potentially be responsible for the commitment costs MISO incurs in clearing the day-ahead market or in the MISO RAC process. Thus, if the Companies were to self-schedule generation to serve their load, the Companies would nevertheless incur a share of MISO's Security-Constrained Unit Commitment ("SCUC") payments and RAC revenue sufficiency guarantee payment costs. Under the current prevailing market conditions and regulations, the Companies incur no such costs.

However, self-scheduling does not allow the Companies to avoid paying the costs of MISO SCUC revenue guarantees. MISO only "expects" that the market clearing price for LMPs in its energy markets will provide sufficient revenues to cover the revenue sufficiency guarantee. Only if the Companies accurately and precisely schedule in the day-ahead market and do not deviate from these schedules in the real-time can the Companies avoid paying the MISO RAC guarantee. In my opinion, there is only a remote possibility that the Companies can precisely forecast and schedule day-ahead and not deviate from the schedules in real-time. This is because the Companies' real-time load changes moment to moment due to factors such as cloud-cover, temperature, wind, and precipitation, none of which -- nor their effects -- the Companies can precisely predict a day in advance. The chance that the Companies would not deviate in real-time from their day-ahead schedule is infinitesimal.

Q. **In the proposed Day 2 market, is there any potential impact to the Companies' ability to manage their interruptible retail customers?**

A. Yes. Under the proposed Day 2 market, the Companies' interruptible retail customers will be available to MISO through MISO directives to the Companies to serve MISO's coincident demand. The Companies' interruptible load is a part of the Companies' integrated resources and Section 70.1.1 of the MISO EMT provides that interruptible demand used to satisfy state or Regional Reliability Council resource adequacy be available for commitment and dispatch by MISO at MISO's discretion. As market participants, the Companies will be required to interrupt these customers when instructed by MISO. Section 70.1.1 detracts from the authority the Companies need to fulfill their obligation to serve native load.

Q. Do the Companies have any concern related to counterparty creditworthiness in MISO Day 2 that does not exist today?

A. Yes. MISO Day 2 exposes the Companies to credit risks they would not otherwise incur. Today, the Companies do business in the wholesale market only with those parties that meet the Companies' strict creditworthiness standards. In MISO Day 2, the Companies will lose the ability to choose with whom they do business in the MISO footprint because the entire market will be accumulated into one credit "pool." The EMT creates this pool because all market participants pay MISO for the power and other products and services they receive, and MISO pays all market participants the revenues due them. In other words, a power supplier is never "paired" with a power purchaser in Day 2; no contract will exist between any two such entities. MISO will be the only entity that has the ability to determine whether any given market participant is sufficiently creditworthy to participate in the Day 2 markets. Thus, if a market participant should default and fail to meet a financial obligation to MISO (e.g., by failing to pay for a power purchase) and MISO deems that obligation "uncollectible," MISO will socialize the impact of the default by assessing every non-defaulting market participant a charge based on its participation in the Day 2 markets (in terms of credits and charges) at the same time as the default. Therefore, if the Companies charges and credits accounted for 5% of the total non-defaulting charges and credits at the time a market participant defaulted, and that default eventually became uncollectible, the Companies would be charged 5% of the default amount.

MISO must socialize the costs of such defaults because it is a non-profit, pass-through-style entity, so it has no assets with which to hold generators harmless from purchasers' defaults -- it must pass the costs through to someone. Therefore, to the extent that MISO allows entities that would not meet the Companies' creditworthiness standards to participate in Day 2, MISO imposes credit risks and costs on the Companies that they do not face today.

MISO's Day 2 creditworthiness approach will also leave the Companies unable to determine their exposure to counterparties to whom the Companies currently extend credit. For example, if the Companies have determined that Counterparty X should only be allowed $10 million in credit and have extended Counterparty X $9 million in credit through non-MISO activities already, in Day 2 MISO could expose the Companies to more than $1 million in additional credit risk from Counterparty X without the Companies being aware of it or able to decline it. In other words, MISO's hampering of the Companies' ability to make intelligent, informed decisions about credit risk will extend not only to counterparties with whom the Companies would never do business, but also to those to whom the Companies extend credit today.

Q. **Do the Companies have any additional concerns relating to their ability to manage risk in MISO Day 2?**

A. According to the Companies' analysis of the various alternatives, MISO presents the greatest number of risks. Certain risks that the Companies have identified and about which LG&E has testified as being associated with RTO/ISO market implementations are listed in the matrix below. The Companies have not attempted to quantify these risks because at this juncture in the MISO Day 2 formation process, the items do not lend themselves to reliable quantification. Nevertheless, the Companies believe that each of the above identified risks could result in significant adverse financial impacts to the Companies and its rate payers. The matrix indicates whether or not the identified risk is present in each of the various alternatives the Companies have evaluated.

RISK	**MISO**	**PJM**	**SPP**	**TORC**
NCA Congestion Uplift	X			
Grandfathered Option B congestion uplift	X			
Defaulting Market Participant Uplift	X	X		
Less than optimal FTR Portfolio	X	X		
RTO Unit Commit Costs Uplift	X	X		
RTO Resource Adequacy Requirements	X	X		
NERC Functional Split	X	X		
Increasing RTO Admin Costs	X	X	X	
RTO Transmission Expansion Cost Uplift	X	X	X	

It is important to place these risks in context. We know that two of the risks -- NCA and Grandfathered Option B uplift – are included in the Day 2 market, although we have been unable to quantify them. Other risks, such as payment defaults by market participants, appear to be low probability events with potentially significant financial consequences. New markets, regardless of their planning, always have the risks of unforeseen consequences which can have severe impacts on the participants and the public.

Participation in the Wholesale Market

Q. If the Commission authorizes the Companies' to seek exit from MISO, will the Companies be able to identify cost-reducing day ahead and real-time trades?

A. Yes. The Companies currently have the ability to identify cost-reducing day-ahead and real-time trades, and that ability will not be affected by withdrawal from MISO. Further, when MISO Day 2 commences, the Companies will have the ability to buy and sell in the MISO day-ahead and real-time markets regardless of whether or not they remain MISO members.

Q. Do the Companies currently have a staff of hourly and next-day traders whose primary focus is to negotiate next-hour and next-day trades with all counterparties that are willing and capable to transact?

A. Yes. The trading team also utilizes extensively the electronic broker "ICE" and several direct brokers to identify and execute possible transactions. Because today's market operates between all willing buyers and sellers, the Companies believe that all willing trading parties make their desires known to the market through direct or brokered communications. Thus, the Companies believe that all such trades are identified, including any possible cost-reducing trades. These methods of trading are useful and productive with counterparties both in and outside of MISO. These methods generate next-hour and next-day physical as well as financial trades and, based on the Companies' experience, will continue to be useful should the Companies exit MISO.

Q. Do the Companies believe that they can achieve the same OSS net revenues in the wholesale market without MISO membership as they can with it?

A. Yes. As I have shown above, the Companies' analysis indicates that only under assumptions that are most favorable to the Companies' continued MISO membership would the Companies achieve greater OSS net revenues as MISO members than as non-members. Therefore, it is quite likely that the Companies' OSS net revenues would be very similar whether or not they are a member of MISO. MISO's administrative costs are greater than any reasonable amount of additional OSS net revenues the Companies could expect as MISO members in Day 2, as Mr. Morey's testimony and study show. Therefore, the Companies can reasonably expect to be net financial losers in Day 2.

Recommendation

Q. What is your recommendation?

A. Based on the reasons described in my testimony, the Commission should determine that the Companies' continued membership in the MISO is no longer in the public interest. It should further determine that the proposed transfer of the functional control over the Companies' transmission assets from MISO to the Companies on the condition that they acquire reliability services from a third-party reliability coordinator, pending FERC approval, is for a proper purpose and consistent with the public interest.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Martyn Gallus**, being duly sworn, deposes and says he is Senior Vice President of Energy Marketing for LG&E Energy LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

MARTYN GALLUS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of September 2004.

Tammy J. Elzy
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

EXHIBIT MG-1

2003 NPV ($millions)	RTO	TORC Low-Transfer	TORC Baseline	TORC High-Transfer
Native Load				
Fuel Costs	2,752.05	2,760.66	2,759.89	2,752.07
Fixed O&M Costs	293.56	293.56	293.56	293.56
Variable O&M Costs	101.19	101.41	101.28	101.20
Emission Costs	415.16	412.85	416.30	415.19
Market Purchase Costs	130.34	120.28	120.17	129.87
Total Native Load Costs	3692.30	3688.75	3,691.21	3,691.90
Off-System Sales				
Fuel Costs	423.63	388.29	420.88	422.85
Variable O&M Costs	12.85	11.80	12.77	12.84
Emission Costs	54.83	49.77	54.54	54.77
Market Purchase Costs	-	-	-	-
Total Off-System Sales Costs	491.30	449.86	488.19	490.46
Off-System Sales Revenue	(728.60)	(654.76)	(717.69)	(730.46)
Total Costs (Net of Revenue)	3455.00	3483.85	3,461.71	3451.90

APPENDIX A

EXPERIENCE

LG&E Energy Corp. | 07/98 To Present | Louisville, KY

SR. VICE PRESIDENT, ENERGY MARKETING

- Lead a 86-person staff of traders, marketers, and analysts in a 24-hour operation executing transaction in excess of 45 million MWh annually
- Responsible for optimization of LG&E Energy's regulated and non-regulated asset portfolio through the direction of wholesale trading, marketing, fuel procurement and risk management activity
- Led the transformation of a traditional utility dispatch function to comprehensive regional trading and risk management business

LG&E Energy Marketing Inc (LEM) | 02/96 – 07/98 | Louisville, KY

SENIOR VICE PRESIDENT, TRADING

- Managed 25 person proprietary trading group actively involved in electric power, natural gas, coal, and emission allowances.
- Delivered earnings in excess of commitment during highly volatile summer 1998

VICE PRESIDENT, STRUCTURED PRODUCTS

- Directed the structuring, valuation, and risk management of operationally and financially complex transactions
- Developed and marketed structured products to origination team

DIRECTOR, TRADING & RISK MANAGEMENT

- Developed LEM's electric trading capability leading to a top-5 position in industry
- Actively managed the Midwest electric portfolio of physical and financial transactions

Merrill Lynch | 07/94 – 02/96 | New York, NY

VICE PRESIDENT

- Managed the natural gas swaps portfolio to maximize the value of customer transactions and proprietary trading. Portfolio included fixed/floating swaps, pipeline basis swaps, Gas Daily swaps and options, and foreign exchange forwards.
- Market-maker to Merrill Lynch clients and salespeople worldwide.
- Structured and valued customized derivative products used in investment banking and private client strategies.

Citibank, N.A. 05/93 – 07/94 New York, NY
VICE PRESIDENT

- Developed natural gas basis trading capability, including pricing methodology, risk measurement and reporting, and execution.
- Originated commodity swaps and options with Citibank clients.
- Structured customized hedging solutions using a variety of "plain-vanilla" and exotic derivatives.

Arco Oil and Gas Company 05/91 – 05/93 Dallas, TX
RISK MANAGEMENT ANALYST

- Traded OTC natural gas swaps and options to hedge ARCO's price and volatility exposures.
- Reviewed and evaluated risk into commonly used parameters.
- Designed and marketed derivative products embedded in natural gas contracts.
- Presented comprehensive overviews of risk management and the valuation of derivative products

PLANNING ANALYST

- Evaluated complex pricing provisions in long-term gas contracts including cross-commodity risk, inflation-indexed revenues, and contingent options.

Wharton Econometrics 10/86 – 8/89 Philadelphia, PA
ECONOMIC ANALYST

- Analyzed economic and demographic data, assisted with long-term economic forecasting, contributed written analysis to company publications.

EDUCATION

The University of Michigan 1989 - 1991 Ann Arbor, MI
Graduate School of Business Administration
MASTER OF BUSINESS ADMINISTRATION

Rowan College 1982 - 1986 Glassboro, NJ
BACHELOR OF ARTS IN ECONOMICS

APPENDIX B

METHODOLOGY TO ESTIMATE THE IMPACTS OF RTOs AND DAY 2 MARKETS ON LG&E/KU COST OF SERVICE

The primary economic arguments for the creation of centralized dispatch within an RTO are to reduce costs to serve native load and increase revenues from the elimination of transmission costs from sales of excess generation. This analysis was performed to calculate the economic impacts of a central dispatched system on LGE/KU. The analysis included:

1. Evaluating electricity prices under differing assumptions regarding LGE/KU participation in an RTO and
2. Calculating LGE/KU's cost to serve native load and off-system sales margin under alternative RTO and non-RTO assumptions.

Three software packages were used to perform this analysis:

1. MIDAS Gold (MIDAS) was used to generate the electricity price forecasts,
2. PROSYM was used to evaluate the LGE/KU cost to serve native load and off-system sales margin production cost revenue requirements ("Net Production Cost"), and
3. MUST was used in the calculation of transfer limits used in both MIDAS and PROSYM.[1]

Four PROSYM cases were created to evaluate the impact of RTOs on LGE/KU Net Production Cost.

1. RTO Case – The assumed elimination of the through-and-out transmission rate between MISO and PJM and the movement toward a common market results in no difference in the operational profile between these RTO alternatives. Therefore, this case represents the Net Production Cost of LGE/KU participating in either MISO or PJM.

2. TORC[2] Low Transfer Capability Case – This case applies more restriction on the transmission transfer limits than the TORC Case.

3. TORC Case – This case represents the Net Production Cost of LGE/KU exiting MISO and not participating in an RTO.

4. TORC High Transfer Capability Case – This case applies less restrictive transmission transfer limits to TORC Case.

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[1] MUST is an industry accepted tool for the calculation of transfer limits and is used in the NERC Interchange Distribution Calculator (IDC).

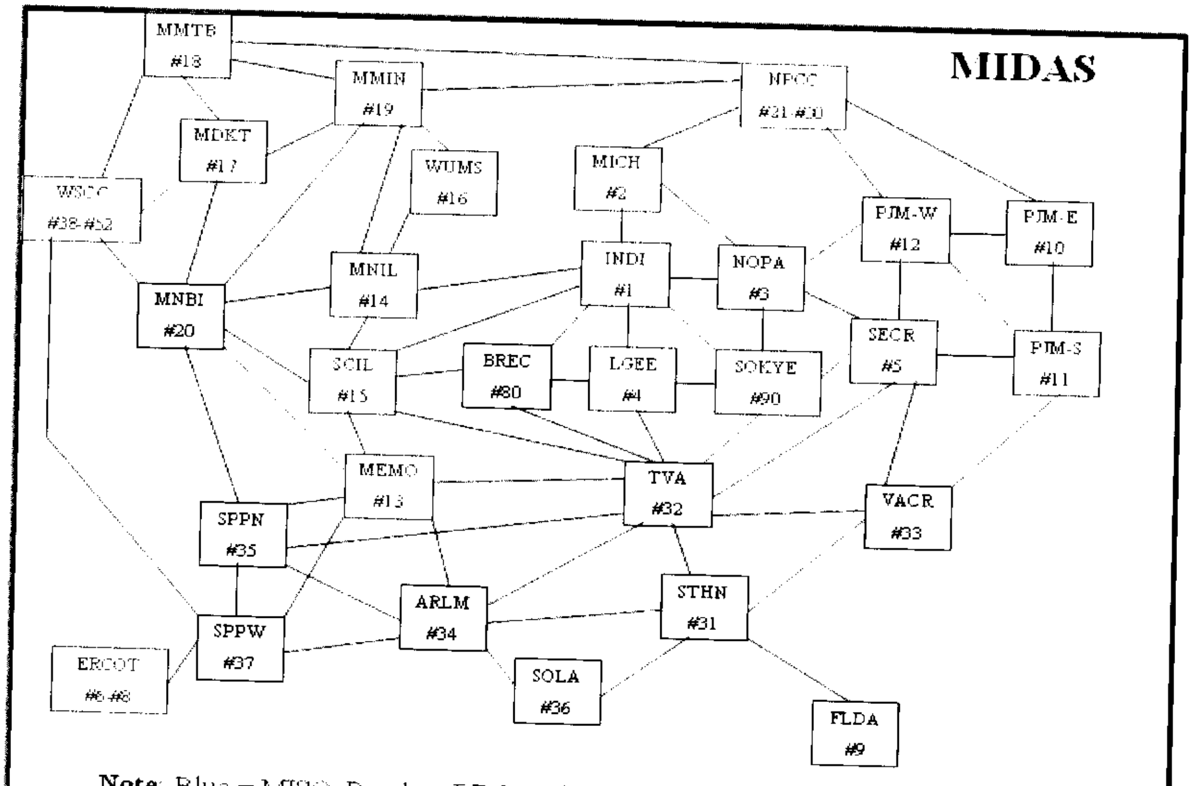
[2] TORC means Transmission Operator with Reliability Coordinator.

Electricity Price Forecasting Methodology

Model Logic

The Transact Analyst module of MIDAS is an hourly, multi-area, chronologically-correct market production cost model used to derive market electricity prices. The model, as employed by LGE/KU, represents the power system operations in the Eastern Interconnect, including representations of approximately 140 control areas that are aggregated up to 26 Regional Transaction Groups. The model matches the control area load forecasts to the 8,000+ generating units of 1 MW or larger and then calculates hourly electricity prices (8,760) for the 26 Transaction Groups by minimizing the cost of serving load subject to certain constraints such as transmission capacity and hurdle rates, fuel costs, emission costs, and generator availability. For this analysis, electricity prices were forecasted for the years 2006-2010. Figure 1 shows the Transaction Group topology for MIDAS used in this study.

Figure 1



Note: Blue = MISO, Purple = PJM, Red = Model Boarder, Black = Other

Generation

MIDAS generation information comes from Platt's 2004 BaseCase database which aggregates data comes from a variety of public sources. These include:

- 2002 and 2003 FERC Form 1,
- U.S. Energy Information Administration,
- U.S. Environmental Protection Agency (EPA) including submissions to meet their Continuous Emissions Monitoring System (CEMS) reporting requirements, and
- NERC Energy Supply and Demand database and Generating Availability Data System (GADS).

This data includes generator name, location (area assignment), summer/winter capacity, primary and secondary fuels, GADS category, operating & maintenance (O&M) costs, heat rates, projected capacity changes, projected retirement dates, and average monthly hydro energy. Defaults values for forced outage rates, forced outage durations, and scheduled maintenance requirements are taken from NERC GADS. Emission production rates for SO2 and NOx are taken from documents published by the EPA.

Because MIDAS is capable of forecasting electricity prices over long periods of time, information on potential new generating units is needed to meet future load growth. These new generating units are modeled in one of two ways:

1. Generating units that are currently under advanced stages of development or construction are assumed to be completed according to publicly announced schedules, or
2. Absent specific information on new units, MIDAS will economically "construct" a "generic" unit to maintain a 12% reserve margin. It optimizes among three types of units: pulverized coal, natural gas combined cycle, or a natural gas simple cycle combustion turbine. During the study period (2005-2010) no "generic" units are built to meet reserve margin needs.

Load

Peak demand and energy forecasts are provided by Platt's BaseCase for each control area. Platt's gets its information from Form EIA 714, NERC Energy Supply & Demand (ES&D), and NERC regional summer/winter assessments. The BaseCase file for this study contains 2002 vintage forecast. Because each control area forecast may be based on different chronological load shapes, the forecasts are scaled to match a reference historical load shape. This preserves the level of the forecasts while at the same time applying regional diversity based on historical experience.

Fuel Prices

Natural Gas/Oil

The gas and oil fuel price forecasts were developed using two components: commodity price and transportation. The commodity price is based on the NYMEX futures price. The transportation component (or basis) reflects geographic differences between hub prices and delivered costs and, for oil, the relationship between the delivered fuels costs to utilities and crude oil futures prices. The commodity prices were based on the 5/25/2004 NYMEX forward prices.

Coal/Uranium

The coal price forecast for each generator consists of two components: commodity price and transportation. The coal commodity price forecast was developed by weighting observed forward coal prices with a proprietary Hill & Associates forecast prepared in Spring 2004 specifically for LGE/KU. This methodology was used due to the lack of long-term liquidity and price discovery for the numerous varieties of coal specifications. The price forecast weights the forward price data more heavily in the near term where there is more market depth and liquidity. The weighting of the forward prices diminishes by year until 2009 when the Hill & Associates forecast is solely utilized.

There are five coal commodity price forecasts used in MIDAS, one for each of the major coal types which are differentiated by sulfur content. Each coal-fired generator is assigned a coal type based on its historical usage. Forecasts of the transportation cost of moving each of the coal types to a plant was developed by Hill & Associates. The delivered coal cost to each plant is determined by adding the commodity price and the appropriate transportation cost.

The uranium price forecast was taken from Platts BaseCase product and represents regional nuclear fuel costs.

NOx and SO_2 Emission Allowance Prices

Forecasts of NOx and SO_2 prices are based on forecasts by Hill & Associates.

Transmission

Transfer Capability

Each Transaction Group within MIDAS is constructed such that there are no significant transmission constraints that would materially impact electricity prices. In effect, MIDAS assumes generation within each Transaction Group can move freely. However, transmission constraints, both physical and economic (hurdle rates) are assumed to exist between Transaction Groups. The transfer capability between Transaction Groups was derived from a variety of sources. The Platts BaseCase data was the primary source for transfer capability and was supplemented by reviewing information from the latest NERC assessment studies as well as other NERC regional reliability assessment studies. For transfer capability between Transaction Groups that did not correspond well to published regional studies, the MUST software tool was utilized to confirm the appropriate transfer limitations using a NERC Multiregional Modeling Working Group (MMWG) base powerflow model. The base power flow model used to calculate these transfer capabilities was the NERC MMWG Summer 2005 model that was created in 2003.

<u>Hurdle Rates</u>

Hurdle rates between Transaction Groups in MIDAS were used to account for transmission wheeling costs as well as transactional costs. The transmission component represents the typical transmission wheeling cost for the region. The transaction cost represents the "cost" of conducting trades whether in a bilateral or centrally dispatched market.

The transmission component was set to zero for all paths between Transaction Groups that were identified as being in either MISO or PJM. This is to reflect the elimination of the regional through and out rates for the two RTOs that is to be effective on December 1, 2004. The transmission component was generally set to $3 on-peak and $2 off-peak for all other paths into or out of the MISO/PJM transaction groups and between Transaction Groups external to the two RTOs. This cost is reflective of the typical hourly transmission cost in the region.

The transaction cost component was set to $1 for all transaction paths in MIDAS including those paths between MISO and PJM transaction groups. This reflects the assumption that transactions will not take place with little or no profit, even in a centrally dispatched market such as MISO or PJM.

Wholesale Electricity Price Cases

Two wholesale electricity price forecasts were generated to represent LGE/KU in and out of a RTO. In the RTO case, the hurdle rate between the LGEE transaction group and its neighbors reflects only the $1 transaction cost whereas in the TORC Case, the hurdle rate also includes transmission costs (see Table 1).

Table 1
Hurdle Rates

$/MWh	**RTO Case**		**Standalone Case**	
Path	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
LGEE to INDI	$1	$1	$4	$3
LGEE to SOKYE	$1	$1	$4	$3
LGEE to BREC	$4	$3	$4	$3
LGEE to TVA	$4	$3	$4	$3
INDI to LGEE	$1	$1	$4	$3
SOKYE to LGEE	$1	$1	$4	$3
BREC to LGEE	$4	$3	$4	$3
TVA to LGEE	$4	$3	$4	$3

To represent the primary markets in the PROSYM analysis, three Transaction Groups connected to LGEE were used:

- The MISO market prices were represented by Transaction Group #1 INDI,
- The PJM market prices were represented by Transaction Group #90 SOKYE, and

- The TVA market prices were represented by Transaction Group #32 TVA

Price / Load Correlation

MIDAS hourly electricity prices are calculated based on a historical reference year load shape. Since wholesale electricity prices are highly correlated with load and the LGE/KU load forecast used in PROSYM has a chronological load shape that differs from that used in MIDAS, it was important to reorder the MIDAS price forecasts to correspond to the LGE/KU load forecast. This reordering did not change the monthly average electricity prices. Table 2 shows the average annual electricity prices by peak type for the three cases.

Table 2
MIDAS Wholesale Electricity Prices

$/MWh		RTO Case			Standalone Case		
	Year	**PJM**	**MISO**	**TVA**	**PJM**	**MISO**	**TVA**
Peak 5x16	2005	49.28	48.96	49.63	49.28	48.84	49.84
	2006	47.68	47.30	47.87	47.75	47.29	48.03
	2007	46.34	45.89	46.32	46.39	45.88	46.37
	2008	45.98	45.42	45.62	45.98	45.38	45.62
	2009	45.74	45.18	45.34	45.78	45.21	45.33
	2010	48.46	47.93	47.71	48.51	47.97	47.68
Off-Peak 7x8	2005	26.68	26.24	28.23	26.69	26.14	28.37
	2006	27.23	26.83	28.75	27.26	26.72	28.89
	2007	27.10	26.66	28.69	27.14	26.58	28.84
	2008	27.09	26.63	28.51	27.12	26.50	28.75
	2009	26.90	26.46	28.24	26.93	26.32	28.54
	2010	29.19	28.86	30.44	29.18	28.68	30.67
Weekend Peak 2x16	2005	32.48	31.91	33.94	32.51	31.80	34.16
	2006	32.89	32.48	34.25	32.94	32.36	34.46
	2007	32.70	32.26	34.02	32.72	32.16	34.21
	2008	32.82	32.41	33.94	32.85	32.24	34.28
	2009	33.05	32.62	34.14	33.07	32.45	34.43
	2010	36.16	35.83	36.89	36.15	35.65	37.15

LGE/KU Production Cost Modeling

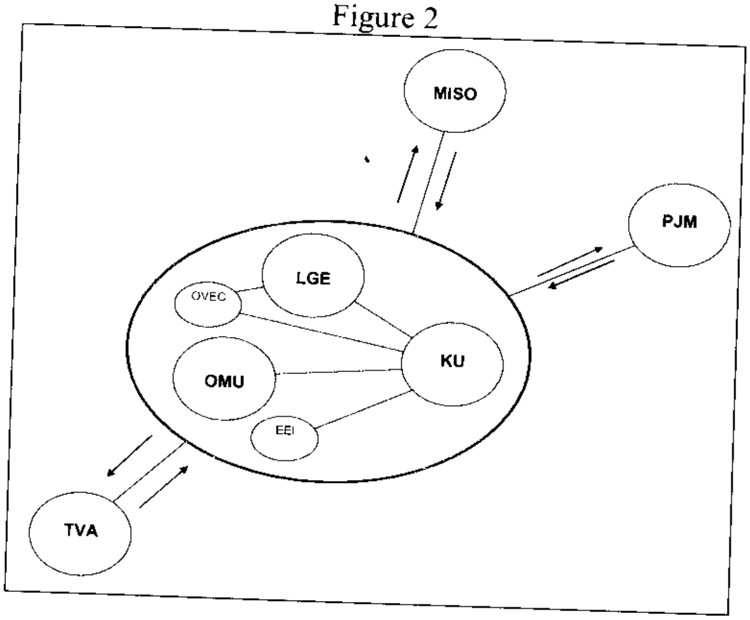
The PROSYM production costing model was used to evaluate the production costs associated with each of the RTO and Day 2 market scenarios. PROSYM is a product of *Henwood Energy Services, Inc.* It is a chronological electric utility production simulation modeling system that is designed for performing planning and operational studies on an hourly basis. It uses convergent Monte Carlo analysis to give the least cost and most economical dispatch of generation resources and simulates the Power Supply System Agreement (PSSA) joint dispatch of the LGE and KU systems. PROSYM is able to simulate the utilization of typical generation resources such as generating units and also the purchased power alternatives considered in this analysis.

The LGE/KU system was allowed to transact with three market areas: MISO, PJM and TVA. Hourly prices for the study period were provided by MIDAS for each market. Using the transfer limitations described in more detail below, the model could buy or sell to all markets, with the exception that market sales and purchases could not simultaneously occur in any given hour.

While LGE/KU is connected to Big Rivers Electric Corporation ("BREC"), this market was not used in the analysis because:

- creating a fourth market in PROSYM would have added model complexity without altering the basic analysis since the difference in the wholesale electricity prices between the BREC and INDI transaction groups is insignificant,
- LGE/KU has a non-regulated affiliate (Western Kentucky Energy) that leases the BREC generators which limits the opportunity for trade, and
- the BREC system is typically long coal-fired generation (similar to LGE/KU) which means it is generally a net seller in the market just like LGE/KU.

Figure 2



Generation

The dispatch of the LGE/KU generating units (including their share of EEI and OVEC) was done on a least-cost basis to meet the combined native load of LGE/KU and off-system sales opportunities. The OMU resources are used to cover their native load obligations and any excess generation is placed in the dispatch order to economically cover LGE/KU load obligations. For the purposes of these studies, it was assumed that LGE/KU built no new generating resources. To the extent that LGE/KU fell below the targeted 14 percent reserve margin, peaking capacity was assumed to be purchased from the market.

Load

The native load forecast utilized in this study was developed in February 2004 and is LGE/KU's most recent forecast (see Table 3). In addition to this study, the load forecast is being used for expansion planning, least-cost revenue requirements analysis and various other analyses.

Table 3

February 2004
Combined LGE/KU Load Forecast

Year	Peak MW	Energy Sales GWh
2005	6,629	34,468
2006	6,722	35,143
2007	6,842	35,954
2008	7,006	36,796
2009	7,153	37,461
2010	7,264	38,121

Fuel Prices

Natural Gas/Oil
Assumptions reflect existing contracts for their duration and the same methodology as that used in MIDAS thereafter.

Coal
Assumptions reflect existing contracts for their duration and the same methodology as that used in MIDAS thereafter.

Transmission Transfer Capabilities

The physical transfer limitations between LGE/KU and the three markets areas were calculated using MUST. Cinergy was used as the proxy for the MISO market and AEP was used as the proxy for the PJM market in the calculation of the transfer limits (See Tables 5). The NERC MMWG Summer 2005 powerflow model created in 2003 was used to calculate a single limit for all hours. This assumption likely understates the amount of transfer capability that would be available during a majority of hours during the year. To simulate the underutilization of flowgates due to the TLR process as the MISO testified is appropriate, all equipment ratings were reduced in MUST by 9.3% in determining the transfer limitations.[3] This case was utilized in the "TORC" analysis.

[3] In the Matter of: Investigation Into The Membership of Louisville Gas and Electric Co. and Kentucky Utilities Co. In the Midwest Independent Transmission System Operator, Inc., Case No. 2003-00266, Pre-filed Testimony of Ronald R. McNamara (12/29/2003) at 8.

Hurdle Rates

Hurdle rates were used in the PROSYM model to represent the transmission cost between LGE/KU and the three markets. The hurdle rates were set to zero between LGE/KU and the MISO and PJM markets for the cases where LGE/KU was a member of either MISO or PJM (See Tables 5). This is consistent with the elimination of the regional through and out rates for the two RTOs effective December 1, 2004. However, for transactions with the TVA market, the hurdle rate assumes that LGE/KU, as the transmission owner, receives back approximately 45% of every transmission expense dollar when it sells to the TVA market. When LGE/KU purchase power from the TVA market, it is assumed that they will have to pay TVA transmission charges.

In the TORC case, it is assumed to be costless for LGE/KU to sell energy off-system to any market since it would be paying itself for transmission. When LGE/KU purchase energy from the market, it is assumed that they pay transmission charges (see Tables 5 and 6).

Table 5
LGE/KU RTO Participation Assumptions

Case	MIDAS Price Forecast	MISO				PJM				TVA			
		XM Limits		Hurdle Rate		XM Limits		Hurdle Rate		XM Limits		Hurdle Rate	
		To	From	To	From	To	From	To	From	To	From	To	From
1	RTO	1480	980	$0/$0	$0/$0	450	1600	$0/$0	$0/$0	330	0	$1.35/$0.90	$3/$2
2	Stand alone	1050	640	$0/$0	$3/$2	0	1040	$0/$0	$3/$2	0	0	$0/$0	$3/$2
3	Stand alone	1265	810	$0/$0	$3/$2	225	1320	$0/$0	$3/$2	165	0	$0/$0	$3/$2
4	Stand Alone	1480	980	$0/$0	$0/$0	450	1600	$0/$0	$0/$0	330	0	$1.35/$0.90	$3/$2

Case Analysis

Four cases were prepared using the PROSYM LGE/KU Production Cost Model to simulate various operating environments. These cases varied wholesale electricity prices and transmission transfer capabilities. These are described in the following bullets and the Table 5 above:

1. <u>RTO Case</u> – The assumed elimination of the through-and-out transmission rate between MISO and PJM and the movement toward a common market results in no difference in the operational profile between these RTO alternatives. Therefore, this case represents the Net Production Cost of LGE/KU participating in either MISO or PJM.

2. <u>TORC Low Transfer Capability Case</u> – This case applies more restriction on the transmission transfer limits than the TORC Case.

3. TORC Case – This case represents the Net Production Cost of LGE/KU exiting MISO and not participating in an RTO.

4. TORC High Transfer Capability Case – This case applies less restrictive transmission transfer limits to TORC Case.

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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	)	**CASE NO. 2003-00266**

SUPPLEMENTAL TESTIMONY OF
MATHEW J. MOREY
Consulting Division, Laurits R. Christensen Associates, Inc.

ON BEHALF OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY

Filed September 29, 2004

Name and Qualifications

Q. Please state your name, current position and business address.

A. My name is Mathew J. Morey. I am Senior Consultant with Laurits R. Christensen Associates, Inc. My business address is 409 Cambridge Road, Alexandria, Virginia. Laurits R. Christensen Associates, Inc.'s principal business address is 4610 University Avenue, Suite 700, Madison, Wisconsin.

Q. Please describe your education and professional background and qualifications.

A. I received my doctorate in economics and statistics from the University of Illinois in 1977. For the next twenty years, I taught econometrics and statistics and worked as a consultant to regulators and to entities in the telephone, natural gas and electricity industries.

From 1996 to 2000, I served as the Chief Economist at the Edison Electric Institute. As Chief Economist, I was responsible for the preparation and supervision of all economic analyses, the analyses of the economic implications of regulatory policy changes as they pertain to the electric industry and the development of principled positions on regulatory policy and legislation at the state and federal levels affecting the energy industries, electricity particularly. Prior to joining Christensen Associates in 2003, I was a Principal of Envision Consulting.

A complete list of my work can be found in the Exhibit MJM-1, attached hereto.

Q. Have you previously testified before the Kentucky Public Service Commission?

A. Yes, I submitted direct and rebuttal testimony to this Commission on behalf of the

Companies in 2003 in this same case, Case No. 2003-00266.

Q. Did you prepare this testimony and the accompanying exhibit or was this exhibit prepared under your direct supervision?

A. Yes, I personally prepared this testimony. The accompanying Exhibit MJM-2, which is the supplemental cost-benefit study (hereinafter "Supplemental Investigation") that I performed, was partly prepared by me and partly prepared under my direct supervision. Some of the quantitative estimates used in the Supplemental Investigation were prepared by the staff of Louisville Gas and Electricity Company and Kentucky Utilities Company (hereinafter collectively referred to as "Companies" or "LG&E/KU"), and are discussed in greater detail in testimony provided by Mr. Martyn Gallus submitted on behalf of the Companies.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the Supplemental Investigation prepared by Christensen Associates of the relative benefits and costs of the various Regional Transmission Organization ("RTO") options and non-RTO options that the Kentucky Public Service Commission ("Commission") has ordered the Companies to examine.

Q. What options have been examined in the Supplemental Investigation?

A. These options consist of the following: (1) remaining a member of the Midwest Independent Transmission System Operator, Inc. ("MISO") RTO within the context of the proposed Day 2 Market administered by MISO under the Energy Markets Tariff ("EMT") (hereinafter referred to as the "MISO Base Case"), (2) joining the PJM Interconnection, LLC ("PJM") RTO (hereinafter referred to as the "PJM RTO Case"), (3) joining the Southwest Power Pool (SPP) RTO (hereinafter referred to as the "SPP RTO Case"), and (3) operating as a Transmission Operator with Reliability Coordinator (hereinafter referred to as the "TORC Case").

The object of the study is to provide the Companies and the Commission with an unbiased assessment of the benefits and costs to the Companies and Kentucky retail electric customers of each of the three alternatives relative to the MISO Base Case. The full details of the analysis conducted by Christensen Associates are contained in Exhibit MJM-2, attached hereto.

Q. What issues do you address in your testimony?

A. My testimony summarizes the results of the Supplemental Investigation. The Supplemental Investigation addressed the question of whether the benefits of continued membership in MISO, the MISO Base Case, outweigh the costs of that option for the Companies and their customers and whether there might be an alternative RTO, such as the PJM RTO or the SPP RTO, or a non-RTO option, such as the TORC option, that would be able to provide an equivalent set of services at a lower cost or provide greater benefits at the same cost as the MISO RTO option.

Purpose of the Supplemental Investigation

Q. What questions were you attempting to answer by conducting the Supplemental Investigation?

A. Specifically, we attempted to answer two questions. The first question we addressed was whether the alternative RTO participation options (PJM RTO Case and SPP RTO Case) might offer potentially greater benefits than the MISO Base Case at the same cost or provide an equivalent set of benefits to the Companies and Kentucky retail customers at a lower cost.

The second question we addressed involved a reexamination of the comparison that was the central focus of the initial proceeding in this case; namely whether the TORC option (referred to in the initial proceeding as the "Standalone option") offers an equivalent set of benefits at a lower cost than the MISO membership option. This question was extended to consider the TORC Case in comparison to the PJM RTO and SPP RTO Cases to determine whether the TORC option also offered equivalent benefits at lower costs than those alternative RTO options.

Q. What was the conclusion reached in the first cost-benefit study you conducted?

A. The initial cost-benefit study I conducted ("First CB Study") examined four RTO options: continued MISO membership; membership in the SeTrans RTO; creation of a statewide Independent System Operator (Statewide ISO); and the Standalone option (now referred to as the TORC option). The First CB Study concluded that the TORC option was, on the basis of the available quantitative evidence and a qualitative assessment of hard-to-quantify factors, economically superior to all of the RTO options. It also concluded that, if an RTO option were to be chosen from among those evaluated, the MISO RTO membership was economically preferred.

The First CB Study found that, relative to continued MISO membership, the present value to 2003 of the net benefit of the TORC option was $30.2 million (PV to 2003, 2005-2010) ($43.8 million in nominal dollars). In my rebuttal testimony, the present value of this net benefit was revised upward to $47.1 million (PV to 2003, 2005-2010) to reflect additional information supplied by MISO in its direct testimony.

Q. Has the Supplemental Investigation altered the conclusion that was reached in the First CB Study?

A. No. The Supplemental Investigation has confirmed the results of the First CB Study. The TORC option remains, on the basis of the quantifiable benefits and costs, the economically superior option. The results of the quantitative assessment of costs and revenues for the Companies are summarized in Tables 1 and 2 below. The results presented in these tables correspond to three scenarios examined for the TORC Case. The three scenarios are differentiated by changes in the assumptions in the production cost modeling conducted by the Companies' staff regarding transmission transfer capabilities and wheeling rates. Wheeling rates are also referred to as hurdle rates. A baseline scenario (hereinafter "TORC Baseline Scenario") involves assumptions about transmission transfer capability and hurdle rates that are believed to be in line with what is most plausible under the TORC option.

However, because there is so much uncertainty about what the state of the world will actually be during the study period, and because the MISO Base Case and the PJM RTO Case were modeled in the production cost simulation as if they represented the most ideal state of the world, it was decided that the best approach in the TORC Case was to test the sensitivity of the results to changes in assumptions about these two key variables. Therefore, two additional scenarios were examined: a "TORC Low-Transfer Scenario" in which the transmission transfer limits are reduced relative to the TORC Baseline Scenario, and a

"TORC High-Transfer Scenario" in which the transfer limits were set equal to the limits in the MISO Base and PJM RTO Cases and the hurdle rates were set equal to the hurdle rates in the MISO Base and the PJM RTO Cases. I will elaborate on the details of these scenarios in a moment.

Table 1. Present Value of Costs and Revenues for RTO and Non-RTO Options
(Positive numbers are costs; Negative numbers are revenues)
(All numbers are PV to 2003 for the period 2005-2010)

Category	MISO RTO Base Case	PJM RTO Case	SPP RTO Case	TORC Baseline Scenario	TORC Low-Transfer Scenario	TORC High-Transfer Scenario
Administrative Costs	65.56	75.59	30.47	-	-	-
Operations Costs						
A&G Costs Associated with RTO Membership Status	12.40	12.40	8.02	8.02	8.02	8.02
Generation Costs						
Native Load	3,692.30	3,692.30	3,691.21	3,691.21	3,688.75	3,691.90
Off-system Sales	491.30	491.30	488.19	488.19	449.86	490.46
Transmission System Operation Costs	-	-	-	2.48	2.48	2.48
Transmission Usage Costs	103.16	103.16	9.45	9.45	9.45	10.23
Uplift Charges	6.09	-	-	-	-	-
Legal, Regulatory & Transaction Costs	3.78	3.78	2.83	1.89	1.89	1.89
Total Costs	4,374.59	4,403.33	4,254.98	4,226.05	4,185.25	4,229.78
Revenues						
Transmission Revenues	(46.82)	(46.82)	(18.78)	(18.78)	(18.78)	(18.78)
Off-system Sales Revenue	(728.60)	(728.60)	(717.69)	(717.69)	(654.76)	(730.46)
FTR Revenues	(83.54)	(85.13)	-	-	-	-
Total Revenues	(858.96)	(860.54)	(736.47)	(736.47)	(673.54)	(749.24)
Net Recurring Cost	3,515.63	3,517.98	3,493.71	3,464.78	3,486.90	3,455.73
Non-recurring Cost (Exit Fee)	-	24.81	24.81	24.81	24.81	24.81
Years to Break Even Point	NA	NA	4-5	1-2	3-4	1-2

Table 2 Differences of Present Values Among RTO and Non-RTO Options
(Positive numbers are net costs; Negative numbers are benefits)
(All numbers are PV to 2003 for the period 2005-2010)

Category	MISO Base Case minus PJM Case	MISO Base Case minus SPP Case	MISO Base Case minus TORC Baseline Scenario	MISO Base Case minus TORC Low-Transfer Scenario	MISO Base Case minus TORC High-Transfer Scenario
Administrative Costs	(10.03)	35.09	65.56	65.56	65.56
Operations Costs					
A&G Costs Associated with RTO Membership Status	-	4.38	4.38	4.38	4.38
Generation Costs					
Native Load	-	1.09	1.09	3.55	0.40
Off-system Sales	-	3.11	3.11	41.45	0.84
Transmission System Operation Costs	-	-	(2.48)	(2.48)	(2.48)
Transmission Usage Costs	-	93.71	93.71	93.71	92.93
Uplift Charges	6.09	6.09	6.09	6.09	6.09
Legal, Regulatory & Transaction Costs	-	0.94	1.89	1.89	1.89
Total Costs	(28.75)	119.61	148.53	189.34	144.80
Revenues					
Transmission Revenues	-	(28.04)	(28.04)	(28.04)	(28.04)
Off-system Sales Revenue	-	(10.91)	(10.91)	(73.84)	1.87
FTRs	1.58	(83.54)	(83.54)	(83.54)	(83.54)
Total Revenues	1.58	(122.49)	(122.49)	(185.42)	(109.72)
Difference in Net Recurring Cost	(2.35)	21.92	50.85	28.73	59.90
Difference in Non-recurring Cost (Exit Fee)	(24.81)	(24.81)	(24.81)	(24.81)	(24.81)
Years to Break Even Point	NA	4-5	1-2	3-4	1-2

Q. What then are the general conclusions that you reach on the basis of the Supplemental Investigation?

The numbers in the last two lines of Table 2 lead to the following overall conclusions:

- The TORC option remains the economically superior option when compared with any RTO option. Depending upon assumptions, the TORC option has net benefits that are between $29 million and $60 million (PV to 2003, 2005-2010) greater than those of the MISO RTO option, if the exit fee is excluded. If the exit fee is included, the Standalone option has net benefits that are between $4 and $35 million (PV to 2003, 2005 – 2010). Under the TORC Baseline Scenario, the simple payback period on the Exit Fee payment is two years.

- Depending on assumptions, if the Companies must be a member of an RTO, the Net Recurring Cost numbers in Tables 1 and Difference in Net Recurring Cost numbers in Table 2, along with the simply payback period estimate, show that the SPP RTO is the superior option. The Difference in Net Recurring Cost of the SPP RTO option is $22 million (PV to 2003, 2005-2010). The break even point on the payment of the Exit Fee is between 4 and 5 years.

Thus, the results of the Supplemental Investigation show that continuation of MISO membership over the study period (2005 to 2010) could cost the Companies and Kentucky retail customers, at a minimum, between $4 million and $35 million (PV to 2003, 2005-2010). The range encompasses the cost of the MISO RTO option estimated in the First CB Study. The best estimate is a value in the middle of this range, in the neighborhood of $30 million (PV to 2003, 2005-2010), taking the exit fee into account.

Q. Please discuss the three TORC Scenarios in more detail?

A. Columns four through six of Table 2 represent estimates of the differences in the present values of the MISO Base Case and each of three scenarios that were developed to establish plausible lower and upper bounds on the revenues and costs for the Companies under a TORC option.

The analysis behind the summary numbers in Tables 1 and 2, which is explained in more detail in Exhibit MJM-2, has two parts. One part involves the modeling of production costs and regional market-clearing prices. This analysis was conducted by the Companies' staff as discussed in the testimony of Mr. Martyn Gallus filed on behalf of the Companies. The outputs from the production cost modeling were taken as inputs to the second part that involved financial evaluation modeling of the various cost and revenue categories, over a range of categories that are assumed to be affected by the Companies' RTO membership status.

Quantifying particular costs and revenues associated with any of the three RTO cases and the one non-RTO case considered in this investigation is challenging. With any study of this kind, there is a great deal of uncertainty about what the future outcomes will be in each of the cost and revenue categories that comprise an estimate of the net cost or net revenue of a particular option and that, in turn, ultimately determine an estimate of the net cost or net benefit of one option compared to another. Naturally, assumptions were made to accomplish this quantification, and hence, with any such study there is a margin of error that enters into the estimates.

In addition, and what may be most important to consider, is that the quantification of costs and benefits only manages to provide a relatively small piece of the picture. There are significant factors that are believed to affect the risks that the Companies will be exposed to as a result of the sea change wrought by moving into the Day 2 Market environment proposed by MISO; many of these factors simply cannot be quantified.

To address the difficulty in estimating the costs and benefits of various options, studies of this sort typically resort to scenario analysis on key variables, that is, factors that drive the estimates of costs or benefits, so that reasonable bounds on the range of cost and benefit outcomes can be established. Scenario analysis is designed to allow improved decision-making by allowing more complete consideration of outcomes and their implications. In particular, scenario analysis is a tool for assessing the risks of a particular course of action and for developing strategies to deal with situations where the future state of the world may differ from what is expected.

The heart of the short-term benefits of RTO membership under a Day 2 Market is believed to be savings in net power procurement costs, which equal the costs of the Companies' own generation plus the costs of power purchases minus revenues from off-system sales. The principal barriers to achieving such savings and benefits under the TORC option are transmission transfer limits, wheeling rates, and, at least in theory, a somewhat more limited ability to identify cost-reducing trades.

To achieve the short-term benefits of RTO membership, the Companies must pay a share of the costs of RTO administration, and in the MISO's case, startup costs. If the kinds of short-term benefits of a Day 2 Market could have been achieved from a TORC option all along, the costs to the Companies of achieving these benefits, now that they are a member of MISO, will be payment of an Exit Fee. Joining another RTO such as PJM or SPP means that the short-term benefits of that RTO membership must exceed the RTO's administration charges plus the Exit Fee. Given the likely size of short-term benefits associated with any alternative RTO membership and the size of the Exit Fee the Companies must pay to leave MISO, the likelihood of finding an alternative RTO that will be preferred to MISO or preferred to the TORC option is very small under any plausible scenario considered.

The core of the Supplemental Investigation involving the scenario analysis examines the impacts of changes in assumptions about the two key factors— transmission transfer limits and wheeling rates— by modeling the Companies' production costs under three different sets of assumptions about these variables. Therefore, there are three scenarios defined for the TORC Case: a TORC Baseline Scenario, a TORC Low-Transfer Scenario, and a TORC High-Transfer Scenario.

Under the TORC Baseline Scenario, it is assumed that the transmission transfer limits are 4.6% lower than the limits in the MISO Base Case and the PJM RTO Case, and that the wheeling rates are $3/MWh higher than in the MISO Base Case and the PJM RTO Case. The TORC Low-Transfer Scenario assumes that transmission transfer limits are 9.3% lower than the MISO Base Case and the PJM RTO Case, and the wheeling rates are $3/MWh higher than the MISO Base Case and the PJM RTO Case. The TORC High-Transfer Scenario assumes that the transmission transfer limits and the wheeling rates are the same as those asumed for the MISO Base Case and PJM RTO Case. The details of these modeling assumptions are provided in the testimony of Martyn Gallus submitted on behalf of the Companies.

Q. What numbers in Table 2 summarize the results of this Supplemental Investigation?

A. The numbers to focus on in Table 2 appear in the last three rows, rows 19 through 21;.row 19 is labeled "Difference in Net Recurring Cost," row 20 is labeled "Difference in Non-recurring Cost (Exit Fee)," and row 21 is labeled "Years to Break Even Point," respectively.

Each of the values in row 19 of Table 2 is equal to the corresponding value for "Net Recurring Cost" for the MISO Base Case minus the corresponding value for "Net Recurring

Cost" of the PJM RTO Case, or the SPP RTO Case or the three TORC Scenarios found in row 19 of Table 1. The values in row 20 of Table 2 equal the values in row 20 of Table 1, and just represent the Exit Fee that must be paid to MISO for the Companies to pursue a more attractive alternative. The values in row 21 of Table 2 represent a simple estimate of the number of years that it would take to recover the Exit Fee payment through the annual savings achieved under the alternative RTO or non-RTO option.

When the value of "Difference in Net Recurring Cost "is negative, as it is for column 2 of Table 2, "MISO Base Case minus PJM RTO Case," it means that the "Net Recurring Cost" under the MISO Base Case is smaller than the "Net Recurring Cost" for the PJM RTO Case, or, in other words, the MISO Base Case offers, in present value to 2003, a net savings for the Companies and Kentucky retail customers compared to the PJM RTO option, over the study period. This is without considering the Exit Fee payment. Hence, the PJM Option over the study period cannot be considered a viable choice; the Exit Fee payment to MISO could not be recovered through savings in production costs over the study period.

When the value of "Difference in Net Recurring Cost" is positive, as it is for columns 3 through 6, in Table 2, it means that the "Net Recurring Cost" under the MISO Base Case is larger than the "Net Recurring Cost" under the corresponding alternative RTO or non-RTO scenario. In other words, the MISO Base Case, in present value to 2003, is more expensive than the alternatives identified in columns 3 through 6. So for example, under the TORC Baseline Scenario, the present value of the annual savings to the Companies and Kentucky retail customers over the study period is shown to be $50 million (PV to 2003, 2005-2010). Assuming the Companies pay an Exit Fee estimated to be $25 million (PV to 2003, 2005-

2010) the TORC option still saves Kentucky retail customers $25 million. According to the simple payback calculations, the Exit Fee payment is recovered through savings in 1 to 2 years. The other TORC Scenarios lead generally to similar conclusions.

The conclusion regarding the SPP RTO option is similar to that for the TORC Scenarios, although the value of "Difference in Net Recurring Cost" between the MISO Base Case and the SPP RTO Case is $21 million (PV to 2003, 2005-2010) and the Exit Fee payment is estimated to be $25 million (PV to 2003, 2005-2010), the simple payback period estimate is 4-5 years; the annual savings achieved from switching to the SPP RTO still enables the Companies to recover the Exit Fee payment before the end of the study period. Considering that the annual savings from the TORC option, under any of the Scenarios considered, and the SPP RTO option, will actually continue well beyond the end of the study period, the conclusion about the SPP RTO option is that it will be economically preferred to the MISO RTO option.

Q. What are the principal differences between the First CB Study and the Supplemental Investigation?

A. A desire to provide the best quantitative and qualitative analysis that could be achieved in a study as far-reaching as this compelled the Companies and Christensen Associates to seek to ensure that the Supplemental Investigation improved upon the previous study. The improvements clarify the differences among the various RTO and non-RTO options and the costs and revenues associated with quantifiable factors. Values of many factors are simply unknown, in particular the fine details associated with the MISO's implementation of the Day 2 Market and administration of the EMT and the costs to the

Companies of that cannot be quantified; only time will tell us what those costs will be. Thus, the Companies and Christensen Associates worked to improve upon the First CB Study through a refinement of the data supporting some of the principal cost and revenue categories.

One means to significantly refine the First CB Study was through the use of production cost modeling and simulation of market-clearing prices in the MISO-PJM region. But for the short time span the Companies and Christensen Associates were given in the initial proceeding to conduct the study and prepare direct testimony—20 days to do the study—the same methods would have been applied. This part of the Supplemental Investigation was conducted by the Companies' staff and is discussed in detail in testimony filed by the Companies' witness Mr. Gallus. The production cost modeling improved on the estimates of the costs of energy to serve native load, including market purchases, costs and revenues associated with off-system sales, and transmission wheeling costs that were used as inputs to the financial evaluation model.

Another improvement from the First CB study is the use of scenario analysis to characterize the uncertainty associated with production costs, off-system sales, and transmission costs. The focus on these elements through scenario analysis reflects the belief that the real drivers of the short-term benefits, if any materialize for the Companies and Kentucky retail customers over the study period, from the MISO or PJM RTO options will come in net power procurement costs.

Additional improvements over the First CB Study arise from a slightly more refined set of estimates of various cost categories, such as transmission system operation costs, uplift and administration charges in the MISO Base Case, and, in the TORC Scenarios, changes in the assumption about the size of transmission revenues (only grandfathered transmission agreements revenue was assumed), and an estimate of the cost of Reliability Coordination and OASIS services provided by an independent third party. More detailed discussion of differences in treatment of cost and revenue categories is found in Section 8 of Exhibit MJM-2.

Factors Considered in the Supplemental Investigation

Q. What factors did you consider as relevant to a determination of the costs and benefits of the alternative options considered compared to the Base Case?

A. The analysis identified and, to the extent possible, quantified what I believed were the principal drivers of the differences in the costs and benefits associated with the Companies staying in MISO relative to the alternatives. These factors are identical to those explored in the First CB Study with the exception that refinements to the estimates of these cost and revenue categories have been made when better data or up-to-date information was available. These drivers include the following factors:

- The MISO Exit Fee (paid to MISO under the all non-MISO Cases),
- RTO administration and implementation costs,
- Administrative and general (A&G) costs that vary with the status of the Companies' RTO membership, including the costs that the generation and transmission divisions incur to ensure that the Companies' system will be smoothly integrated into a Day 2 Market or operate effectively as a TORC. For example, the Companies have contracted to install over $1 million in new

hardware for the Companies' traders to enable the traders to participate in the MISO administered Day 2 Market,

- Transmission usage costs, including payments for transmission wheeling and congestion costs,
- Uplift charge costs (incurred under RTO options when particular costs incurred by the RTO are not directly assigned and are spread to all market participants or to transmission owners on a some *pro rata* basis), and
- Legal, regulatory, and transaction costs (which vary with the Companies' RTO membership status).

Estimates of additional factors included on the revenue side include:

- Transmission revenues, and
- FTR-related revenues (under the MISO and PJM RTO Cases only), including the value of FTRs allocated to the Companies plus the Companies' share of the RTO's revenues from the auction of surplus FTRs.

Q. What factors were not quantified?

A. The list of factors that could affect the costs and benefits of any one of the options considered in this study is, quite frankly, a very long list. It is much longer than the list of factors that have been quantified. Of course, the First CB Study and the Supplemental Investigation have succeeded in quantifying the main drivers of the costs and benefits so that the general size of the relative gains from choosing one option over another are captured. Nevertheless, many small details that will ultimately matter when the Companies participate in a Day 2 Market go unmeasured.

Among the factors that we have not quantified are:

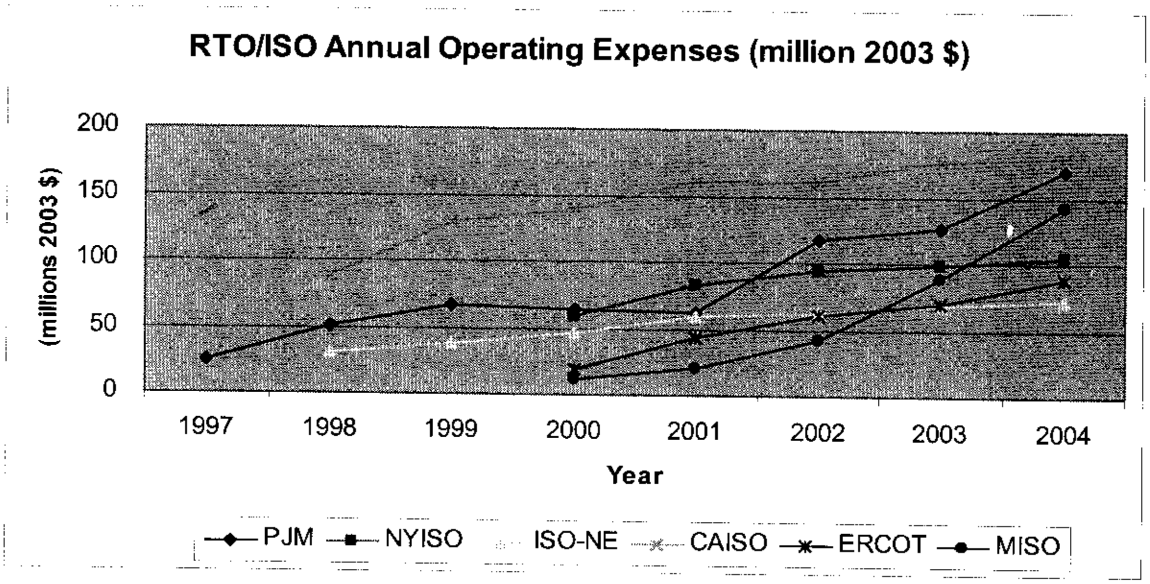
- Reliability, as represented in the probability of a loss of load in association with a problem on the high-voltage transmission system and then converted to a financial impact,
- Tremendous uncertainties associated MISO's administration of the Day 2 Market,
- The numerous costs hidden in the details of the EMT and how MISO will administer it once the energy markets open in March 2005,
- The financial impact regarding higer growth rates in RTO operating and administration costs for MISO, PJM or SPP over the study period,
- A shift from the current SPP RTO Day 1 configuration to a Day 2 Market, and
- Long-term effects of the Day 2 Market under any RTO option.

The issue of reliability, as defined above, was addressed at great length in the initial proceeding. In the First CB Study, the Companies assumed that there was no difference in the level of reliability of the transmission system between the MISO Base Case and the TORC (i.e., Standalone) Case, and therefore, no change in the financial impact on the Companies or Kentucky retail customers. No evidence presented by MISO in the initial proceeding refuted that assumption. I have maintained that assumption in the Supplemental Investigation for all RTO and non-RTO options.

The assumption that there is no change in the level of reliability achieved under any of the RTO or non-RTO cases considered in the Supplemental Investigation should not be conflated with the issue of what it costs to achieve a given standard of reliability across various RTO and non-RTO options. The Supplemental Investigation assumes that that standard can be met under all options and does quantify the cost of achieving that given standard under each option. The fact that the cost of achieving the standard under the RTO options is contained within the administration charges the Companies will pay makes it difficult to isolate that cost and make a direct comparison. Nevertheless, a comparison is made indirectly in terms of the Difference in Net Recurring Cost numbers presented in row 19 of Table 2.

Higher growth rates in RTO administration charges over the study period could have been assumed or explored as a sensitivity case in light of the overwhelming evidence from the historical trends. Figure 1 illustrates this trend in terms of the annual operating costs of the ISOs and RTOs.

Figure 1.
ISO/RTO Annual Operating Costs (including Amortization, Depreciation and Interest Expenses in 2003 dollars)[1]



1 Used with permission from Margot Lutzenhiser, "Comparative Analysis of RTO/ISO Operating Costs," Public Power Council, August 17, 2004.

Summary of the Supplemental Investigation

Q. What are the principal cost differences among the four cases considered in the Supplemental Report?

A. Differences in the costs among the four principal cases, including the three scenarios for the TORC Case, arise in the following categories: the Exit Fee; RTO administration costs; the Companies' A&G costs in generation and transmission, including Reliability Coordinator and OASIS management services in the TORC Case; operational costs under generation, such as fuel costs, emission credit costs and market purchases; off-system sales costs; and transmission costs, including transmission congestion payments.

Differences across the four cases also arise on the revenue side, in particular with respect to off-system sales revenue, transmission revenues, revenues associated with FTRs held in the MISO Base Case and in the PJM RTO Case, and revenues that could be received on a *pro rata basis* by the Companies associated with annual and monthly FTR auctions conducted by MISO and PJM.

Q. What explains the differences between the MISO Base Case and the PJM Change Case?

A. There is actually very little difference between the MISO Base Case and the PJM RTO Case in most categories of costs and revenues. The major difference is that, to switch to PJM, the Companies must pay an Exit Fee, and the small benefits that arise from either lower costs or higher revenues in the PJM RTO Case are not sufficient to make up for the payment of the Exit Fee and the slightly higher administrative charges the Companies would have to pay as members of PJM. Switching to the PJM RTO would not be improving the welfare of the retail customers in Kentucky.

The net result is that MISO membership is estimated to cost the Companies and Kentucky retail customers about $27 million (PV to 2003, 2005-2010) less over the study period than PJM RTO membership, which makes MISO membership preferable to PJM membership.

Q. What is the conclusion about whether the MISO option or the SPP option is economically superior?

A. The results for the SPP RTO option can be expressed in terms of a range of values relative to the MISO Base Case because the production cost modeling for the TORC Case was assumed to hold for the SPP RTO Case. Because of this, the conclusion about whether the MISO RTO option or the SPP RTO option is economically superior is not reached in as direct a way as for the comparison of the MISO Base Case and the PJM RTO Case.

For the SPP option, three scenarios could be considered: an SPP RTO Baseline Scenario, which is the scenario presented in Tables 1 and 2, SPP RTO Low-Transfer Scenario, corresponding to the production cost modeling for the TORC Low-Transfer Scenario, and an SPP RTO High-Transfer Scenario, corresponding to the production cost modeling for the TORC High-Transfer Scenario.

Thus, differences between the MISO Base Case and SPP RTO Case are reflective of differences arising out of the production cost modeling in those three TORC Scenarios, which are discussed under the TORC Case below. It should be noted, however, that for the SPP RTO Case presented in Tables 1 and 2, the basis for the production costs is the TORC Baseline Scenario. Thus, under the Baseline Scenario, SPP membership is estimated to cost the Companies and Kentucky retail customers $3 million (PV to 2003, 2005-2010) more than MISO RTO membership over the study period, when the exit fee is taken into consideration, and will save the Companies and Kentucky retail customers $22 million (PV to 2003, 2005-2010) in production costs and lower administrative costs over the study period.. Therefore, on a present value basis, the MISO RTO membership is marginally preferable to the SPP RTO membership, although, a simple payback period to recover the cost of the Exit Fee is 4 to 5 years.

It is important to keep in mind that the study period defined by the Commission's order is only six years long, short for investigations of this kind. The incremental savings or costs of any option relative to the MISO RTO option will continue beyond the study period, growing relative to the fixed cost of the Exit Fee.

If the SPP RTO option were modeled under the Low-Transfer and High-Transfer Scenarios and compared to the MISO Base Case, the conclusion is mixed. Under the restrictive assumptions of the Low-Transfer Scenario, the SPP RTO option is estimated to cost the Companies and Kentucky retail customers about $19 million (PV to 2003, 2005-2010), including the Exit Fee. But under less restrictive assumptions of the High-Transfer Scenario, the SPP RTO option would save the Companies and Kentucky retail customers $12 million (PV to 2003, 2005-2010) compared to the MISO RTO option, including the Exit Fee. The actual outcome is between these two numbers, making the SPP RTO option a viable economic alternative.

This conclusion, however, should be qualified further by the acknowledgement that the SPP RTO Case has been examined under an assumption that the SPP RTO does not expand the functions and duties it currently performs to include Day 2 Market operations. If the SPP RTO were to expand its role and authority to include Day 2 Market functions similar to those that PJM has been performing for several years and that MISO expects to perform under the EMT beginning in March 2005, SPP RTO's revenue requirement would be expected to increase significantly. Given the tremendous uncertainty about what the startup and implementation costs and annual operational costs would be under such an expansion, the relative attractiveness of that RTO option to the Companies would be reduced concomitantly.

Q. What explains the difference between the MISO option and the TORC option as represented in the three scenarios you examined?

A. Because of the tremendous uncertainty surrounding the actual outcomes of any RTO or non-RTO choice the Companies could make, and the many factors that cannot be quantified by a study of this kind, the most appropriate approach is to estimate a range of the net costs or net benefits through the application of scenario analysis.

For the investigation at hand, scenario analysis can be accomplished for the TORC Case by making assumptions that push key variables in the analysis to reasonable limits and, by so doing, examine relevant scenarios in between. This is a regular practice in business decision making and in developing business strategies in a competitive environment.

And while it would be helpful to be able to assign probabilities to particular scenarios within the range, it is not possible to go that far in a study of this kind. Nevertheless, the range provides a means to assess extremes relative to outcomes more centrally located. The best that may be said is that the upper and lower values of the range are less likely than outcomes in the middle of the range.

The point of this scenario analysis is to demonstrate how the net costs of the MISO option relative to the TORC option increase when the wedge between the two options, represented by transmission limits and hurdle (i.e., wheeling) rates, is reduced. And because there is no way of knowing for certain how big a wedge will exist between the two options, particularly if the MISO option is pursued regardless of the quantitative evidence presented in this Supplemental Investigation, it is worth examining what the possibilities are if the conditions the Companies operate under as a TORC entity do not differ much from the MISO RTO or PJM RTO options.

The results of the TORC Baseline, TORC Low-Transfer, and the TORC High-Transfer Scenarios are presented in Table 1 and compared to the MISO RTO option in Table 2 as I have previously discussed. The major differences between the MISO Base Case and the TORC Scenarios arise in terms of net power procurement costs and differences in several other cost and revenue categories.

Differences in net power procurement costs stem from the assumptions about the transmission transfer limits and wheeling rates that define the three TORC Scenarios. Additional differences arise from Administration Charges paid in the MISO Base Case and net transmission costs. These differences can be seen in columns 4 to 6 of Table 2.

The results of this scenario analysis imply that the short-term benefits of the MISO RTO Day 2 Market for the Companies and Kentucky retail customers may not be significant if the barriers to trade are reduced or removed entirely for the Companies operating in a TORC configuration. Without those short-term benefits in the MISO Base Case, the benefits from other features of the RTO membership are not likely, in the short run, to offset the costs of membership, which are roughly $66 million (PV to 2003, 2005-2010) in RTO administrative service charges.

The impression may be conveyed from the quantitative analysis that the savings from the alternative options are not overwhelmingly large. However, it must be kept in mind that if the Companies were to exit MISO and pursue an alternative, annual savings from that move would be expected to continue beyond the end of the study period for many years. For example, if the study period had been extended to 2019, under an assumption that the net cost of the MISO RTO option relative to the TORC Baseline Scenario in 2010 was assumed to remain constant for the period 2011 to 2019, lengthening the study period to fifteen years, the Difference in Net Recurring Cost would grow to over $88 million (PV to 2003, 2005-2019).

Q. Does that conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF VIRGINIA)
) **SS:**
CITY OF ALEXANDRIA)

The undersigned, **Mathew J. Morey**, being duly sworn, deposes and says he is Senior Consultant with Laurits R. Christensen Associates, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

MATHEW J. MOREY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25nd day of September 2004.

Notary Public

My Commission Expires:

Oct 31, 2004

APPENDIX

MATHEW J. MOREY

RESUME

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Academic Background:

Ph.D., University of Illinois-Urbana/Champaign, 1977, Economics.
M.S., University of Illinois-Urbana/Champaign, 1975, Economics.
B.S., University of Illinois-Urbana/Champaign, 1973, Economics.

Positions Held:

Senior Consultant, Laurits R. Christensen Associates, Inc., July 2003 – present

Principal, Envision Consulting, October 2000 – June, 2003
Director, Economics, Edison Electric Institute, 1996 – October 2000
President, Center for Regulatory Studies, Illinois State University, 1991 – 1996
Vice President, Center for Regulatory Studies, 1985 – 1991
Director of Energy Forecasting, Central Illinois Light Company, 1991 – 1992
Special Term Appointment, Argonne National Laboratory, 1987 – 1992
Associate Professor of Economics, Illinois State University, 1983 – 1996
Assistant Professor of Economics, Indiana University, 1978 – 1983
Assistant Professor of Economics, Arizona State University, 1977 – 1978

Selected Professional Activities:

Research Advisory Committee, National Regulatory Research Institute, 1995-1996

Professional Experience:

I am a Senior Consultant at Christensen Associates. I have a broad experience in the electric industry working on policy issues connected to all aspects of restructuring. I have worked on transmission congestion management and pricing systems, market monitoring, market design and incentive regulation. Prior to joining Christensen, I was Principal of Envision Consulting, which I founded in 2000. I served as Chief Economist with the Edison Electric Institute from 1996 to 2000. I guided the development of EEI's positions on economic and regulatory policy pertaining to the restructuring of the industry's wholesale and retail markets. I directed EEI's economic analyses of the impacts of restructuring proposals and policy options. I focused EEI's economic framework for efficient pricing and practices within competitive and regulated markets, transmission and distribution pricing and rate design, including congestion pricing practices, merger and market power policies at the federal and state level, and energy business development. I have testified numerous times before regulatory agencies and legislative bodies on a wide range of industry restructuring issues including stranded costs, market power, utility codes of conduct, utility-affiliate transfer pricing rules and regulatory policy regarding the design of distribution standby and transmission rates.

Publications:

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SUPPLEMENTAL INVESTIGATION INTO THE COSTS AND BENEFITS TO LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY OF RTO PARTICIPATION OPTIONS

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Executive Summary

In 2003, the Kentucky Public Service Commission (KPSC) initiated an investigation of the membership of Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (LG&E/KU or Companies) in the Midwest Independent Transmission System Operator, Inc. (MISO). In a June 2004 Order, the KPSC ordered that the Companies "should have an opportunity to address the feasibility of joining PJM, or any other RTO, irrespective of its geographic boundaries...[and] should file supplemental testimony addressing the energy market tariffs that have been filed recently by MISO."

In response to the June 2004 Order, the Companies engaged Christensen Associates to conduct a supplementary cost-benefit analysis. This new study (Supplemental Investigation) examines the quantifiable and non-quantifiable (or difficult to quantify) costs and benefits of membership in PJM RTO and the Southwest Power Pool RTO (SPP). Second, the study reexamines benefits and costs of the Companies' participation in the MISO RTO under MISO's proposed Energy Markets Tariff (EMT) and its administration of day-ahead and real-time energy spot markets and application of congestion management system of locational marginal prices (LMPs) and financial transmission rights (FTRs) for hedging congestion costs (Day 2 Market), which is scheduled to go into effect in March of 2005. Thus, three RTO options and one non-RTO option are evaluated in this Supplemental Investigation as follows:

- MISO RTO option (with Day 2 Markets proposed),
- PJM RTO (with Day 2 Markets in place),
- SPP RTO (with no Day 2 Market planned), and
- a Transmission Operator with Reliability Coordinator (TORC) option.

The MISO RTO option is the Base Case; with the latter three cases as the alternatives. The MISO Base Case and the TORC Case were examined in the first cost-benefit investigation (First CB Study). The First CB Study concluded that the TORC option was, on the basis of the available quantitative evidence and a qualitative assessment of hard-to-quantify factors, economically superior to all of the RTO options, which included consideration of the SeTrans RTO and a Statewide Independent System Operator. It also concluded that, if an RTO option was to be chosen from among the three RTO options evaluated, the MISO RTO membership was economically preferred.

Quantifying particular costs and revenues associated with any of the four cases considered in this investigation is challenging. With any study of this kind, there is a great deal of uncertainty about what the future outcomes will be in each of the cost and revenue categories that comprise an estimate of the net cost or net revenue of a particular option and that, in turn, ultimately determine an estimate of the net cost or net benefit of one option compared to another. Naturally, assumptions were made to accomplish this quantification, and hence, with any such study there is a margin of error that enters into the estimates.

In addition, and what may be most important to consider, is that the quantification of costs and benefits only manages to provide a limited piece of the picture. There are significant factors that are believed to affect the risks that the Companies will be exposed to as a result of the sea change wrought by moving into the Day 2 Market environment; these factors simply cannot be quantified easily in some cases or at all in other cases. Among the many factors that we have not quantified are:

- Reliability, as represented in the probability of a loss of load in association with a problem on the high-voltage transmission system and then converted to a financial impact.
- Tremendous uncertainties associated MISO's administration of the Day 2 Market.
- The numerous costs hidden in the details of the EMT and how MISO will administer it once the energy markets open in March 2005.
- Uncertainty regarding the growth in RTO operating and administration costs for MISO, PJM or SPP over the study period.
- A shift from the current SPP RTO Day 1 configuration to a Day 2 Market.

The heart of the short-term benefits of RTO membership under a Day 2 Market is believed to be savings in production costs, power purchases and increases in off-system sales volumes and perhaps net margins. The principal barriers to achieving similar savings and benefits under the TORC option are transmission related: limits on transmission transfer capability (i.e., limits on transmission utilization) and wheeling rates.

To achieve the short-term benefits within an RTO, the cost to the Companies are the charges for RTO administration (i.e., RTO operating costs), and in the MISO's case, RTO startup costs. If the kinds of short-term benefits of a Day 2 Market could have been achieved from the position of a TORC option along, the cost for the Companies, now that they are a member of MISO, will be payment of an exit fee. Joining another RTO such as PJM or SPP means that the short-term benefits of an alternative RTO membership must exceed that RTO's administration charges plus the exit fee the Companies pay to MISO. When the size of short-term benefits of membership in an alternative RTO are compared to the exit fee the Companies must pay to leave MISO and the alternative RTO administration charges, the odds are against finding an alternative RTO that will be beneficial under any plausible scenario.

To address the difficulty in estimating the costs and benefits of various options, studies of this sort typically resort to scenario analysis on key variables (i.e., factors that drive the estimates of costs or benefits) so that plausible bounds on the range of cost and benefit outcomes can be established. The analysis is designed to allow improved decision-making by allowing more complete consideration of outcomes and their implications. In particular, scenario analysis is a tool for assessing the risks of a particular course of action.

Three scenarios were defined for the TORC option: a TORC Baseline Scenario, a TORC Low-Transfer Scenario, and a TORC High-Transfer Scenario. To create the TORC Low-Transfer and TORC High-Transfer Scenarios, changes in two factors were examined: transmission transfer limits and wheeling rates. These two factors were believed to be the most significant in determining plausible bounds on the net costs and benefits of the Companies' RTO options relative to the TORC option. In the production cost modeling, these factors are the two variables that are most likely to affect trades at the margin and, in turn, affect the energy costs of serving native load and off-system sales.

Other scenarios could have been examined by varying assumptions about other quantifiable factors in this study. However, it was believed that such scenarios would have resulted in net costs of the RTO options that were contained within the bounds set by these three basic scenarios.

The results of the Supplemental Investigation lead to the following conclusions (where all dollar figures are present values in 2003 of costs and benefits incurred over the study period 2005-2010):

- The TORC option remains the economically superior option when compared with any RTO option.
- If the Companies must be a member of an RTO, the SPP RTO option is economically superior.
- Under the TORC Baseline Scenario, for the MISO membership option to be beneficial to Kentucky retail customers, the non-quantifiable benefits of the MISO RTO option would have to exceed $50 million excluding the exit fee and $26 million including the exit fee.
- Under the TORC Low-Transfer Scenario, for the MISO RTO option to be beneficial to Kentucky retail customers, over the study period, the sum of the benefits for the MISO Base Case associated with non-quantifiable factors, at a minimum would have to exceed $29 million excluding the exit fee, and $4 million including the exit fee.
- Under the TORC High-Transfer Scenario, for the MISO membership option to be beneficial to Kentucky retail customers, the non-quantifiable benefits of the MISO option would have to exceed $60 million, excluding the exit fee. In other words, the net cost of the MISO RTO option is roughly $60 million excluding the exit fee, and $35 million including the exit fee.

Thus, the results of the Supplemental Investigation demonstrate that the MISO RTO option could cost the Companies and Kentucky retail customers between $29 million and $60 million (PV to 2003), over the study period 2005 to 2010, excluding the exit fee. If the exit fee is considered, the MISO RTO option is estimated to cost the Companies and Kentucky retail customers between $4 million and $35 million (PV to 2003, 2005-2010) over the study period. This range encompasses the cost of the MISO RTO option estimated in the First CB Study. The best estimate is some value within this range, in the neighborhood of $30 million (PV to 2003, 2005-2010) in savings for the Companies and Kentucky retail customers. Since the study period considered in this investigation is short, the present value of the savings under the TORC option would be much larger if the study period were extended to a ten- to fifteen-year period. The estimated value of those savings is $63 million (PV to 2003, 2005-2010) including payment of an exit fee and $88 million (PV to 2003, 2005-2010) without considering the exit fee.

Supplemental Investigation Into the Costs and Benefits to Louisville Gas and Electric Company and Kentucky Utilities Company of RTO Participation Options

1. Introduction

1.1 Reasons for the Supplemental Investigation

In 2003, the Kentucky Public Service Commission (KPSC) initiated an investigation of the membership of Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (Companies) in the Midwest Independent Transmission System Operator, Inc. (MISO).[1] A number of issues were addressed in that initial proceeding, including the costs and benefits to the Companies of membership in MISO; the feasibility of the Companies joining a southern Regional Transmission Organization (RTO), specifically the SeTrans RTO; the feasibility of creating a statewide Independent System Operator (ISO); and the option of withdrawing from the MISO and operating the Companies' system as an independent control area operator with no RTO affiliation, otherwise referred to in this report as the Transmission Operator Reliability Coordinator (TORC). As part of that proceeding, Laurits R. Christensen Associates, Inc. (Christensen Associates) prepared *A Cost-Benefit Analysis of RTO Options for LGE Energy Corporation* (First CB Study), dated September 22, 2003.

A substantial evidentiary record was created in the initial case through discovery, prepared testimony, and two public hearings. However, since the case was initiated, MISO filed with the Federal Energy Regulatory Commission (FERC) new tariffs that provide greater clarity as to how the day-ahead and real-time energy markets will function. In addition, the KPSC authorized Kentucky Power Company (d/b/a American Electric Power (AEP)) to join the PJM Interconnection, L.L.C. RTO (PJM),[2] raising the question of whether the benefits and costs to the Companies' of membership in PJM should be examined in this proceeding to ensure the record is as complete as possible. Therefore, in its June 2004 Order, the KPSC ordered that the Companies "should have an opportunity to address the feasibility of joining PJM, or any other RTO, irrespective of its geographic boundaries...[and] should file supplemental testimony addressing the energy market tariffs that have been filed recently by MISO."[3]

In response to the June 2004 Order, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (hereafter LG&E/KU or Companies) asked Christensen Associates to conduct a supplementary benefit-cost analysis of the Companies' membership in MISO. The principal purposes of the Supplemental Investigation is to reflect recent refinements

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[1] Case No. 2003-00266, *Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.* (July 2003 Order).

[2] Case No. 2002-00475, *Application of Kentucky Power Company d/b/a American Electric Power, For Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218* (June 2004 Order) at 2.

[3] Case No. 2003-00266, *Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, (June 22, 2004) (June 2004 Order), at 2.

to MISO's open access transmission tariff (OATT) and to examine benefits and costs of certain RTO options that were not considered in First CB Study.

1.2 Scope and Purpose of the Supplemental Investigation

This study adds to the evidentiary record in this investigation in two respects. First, it provides, to the extent possible, quantification of the benefits and costs to the Companies of additional RTO options in conformity with the KPSC's July 2004 Order, "irrespective of geographic boundaries." Therefore, the study examines the quantifiable and non-quantifiable (or difficult to quantify) benefits and costs of membership in PJM and the Southwest Power Pool RTO (SPP). Second, the study reexamines benefits and costs of the Companies' participation in the MISO RTO under MISO's proposed and Energy Markets Tariff (EMT), which is scheduled to go into effect in early 2005. The EMT includes day-ahead and real-time spot energy markets, a congestion management system that uses locational marginal prices (LMPs) to define congestion charges, and financial transmission rights (FTRs) that provide hedging protection against congestion costs. The new market created by the EMT is referred to as the Day 2 Market.

This report compares the net costs (or benefits as the case may be) of the MISO, PJM and SPP RTO options with an option in which the Companies operate as a TORC, an option that was defined in the First CB Study (referred to in the First CB Study as the Standalone Case). In other words, the four cases that are examined are defined as follows:

- **Base Case**: Companies remain a member of MISO, with Day 2 Market participation;
- **Change Case 1**: Companies join PJM with participation in PJM's Energy and Capacity Markets;
- **Change Case 2**: Companies join SPP, which acts as Reliability Authority and Coordinator for the Companies among other services that it would perform for the Companies; and
- **Change Case 3**: Companies operate as a TORC with no RTO affiliation.

The Base Case and Change Case 3 were examined in the First CB Study. The Base Case is similar to the Base Case in the First CB Study, except that the current Base Case is more clearly defined by MISO's EMT, which was submitted by MISO to FERC and conditionally approved by FERC after the completion of the First CB Study. Change Case 3 was the option found to have the largest net benefits.

The differences between the MISO Base Case in the First CB Study and the Supplemental Investigation and between the TORC option considered here and the Standalone Case in the First CB Study are primarily due to improvements in the quality of the data that form the basis for the quantitative estimates of costs and benefits. The general methodological approach taken to quantify the costs and benefits and to make comparisons among the RTO and non-RTO options in the First CB Study were sound and consistent with accepted practices for conducting cost-benefit studies of this kind. There have been no changes to that general methodological approach. Notwithstanding the steps taken to improve the accuracy and precision of the Supplemental Investigation, the estimates of costs and benefits produced here are comparable and consistent with those obtained in the First CB Study.

2. Descriptions of the Four Cases

This section provides detailed descriptions of the four RTO options considered in this benefit-cost study. As previously described, these four options are as follows:

- **Base Case**: Companies remain a member of MISO, with Day 2 Market participation;
- **Change Case 1**: Companies join PJM with participation in PJM's Energy and Capacity Markets;
- **Change Case 2**: Companies join SPP as Reliability Authority and Coordinator; and
- **Change Case 3**: Companies operate as a TORC with no RTO affiliation.

Some assumptions are common to all four cases.[4] These include:

- Regional Through and Out Rates (RTORs) between MISO and PJM are eliminated for the entire study period.
- No major regional transmission expansion that could significantly alter the flow or congestion patterns in the MISO or PJM combined footprint is undertaken and completed during the study period.
- American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power & Light (DP&L) and Dominion are members of PJM for the entire study period.

2.1 MISO Participation: Base Case

In the Base Case, the Companies participate fully in MISO's proposed Day 2 Market, consisting of day-ahead and real-time energy spot markets with locational pricing. The Companies also participate in the FTR market, nominating and receiving allocations of FTRs commensurate with network integration transmission service and firm point-to-point transmission service. The allocation will be governed by MISO's proposed four-tiered allocation approach discussed further below.

Through Schedules 10, 16, and 17, the Companies will pay a share of MISO's implementation and administration costs based either on a *pro rata* share or on the basis of the formulas for defining billing determinants, as in the case of Schedules 16 and 17. They may also pay a share of the uplift costs that are associated with the implementation of the EMT as proposed by MISO and as modified to comply with the Federal Energy Regulatory Commission's (FERC's) order conditionally accepting the EMT.[5] In addition, the Companies can expect to bear a portion of the

[4] These assumptions play different roles in the quantitative analysis however, with the first and third common assumptions affecting the modeling of market-clearing prices in the MIDAS program and the second assumption affecting the production cost simulations conducted by the Companies' staff through the application of the PROSYM program. See Martyn Gallus, "Supplemental Testimony of Martyn Gallus," in Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc., Case No. 2003-00266, Filed on September 30, 2004.

[5] Federal Energy Regulatory Commission, *Order Conditionally Accepting Tariff Sheets and To Start Energy Markets and Establishing Settlement Judge Proceedings*, Docket No. ER04-691-000 and Docket No. EL04-104-000, issued August 6, 2004 (August 6 Order).

costs associated with the new Schedule 21, Reactive Supply and Voltage Control from Independent Generation Resources Service.

The Companies are assumed to receive an allocation of FTRs sufficient to hedge congestion costs that would be otherwise borne by Kentucky retail customers. However, this assumption, made for purposes of enabling a sharper comparison between the MISO Base Case and the PJM RTO Change Case, does not reflect the Companies' deep concern over the new risks associated with the MISO's implementation of the FTR allocation process. These risks arise from uncertainties in many of the factors that will ultimately affect the Companies' allocation, and may not permit the resulting allocation to be sufficient to hedge completely the cost of congestion in the Day 2 Market.[6]

Refinements in the Informational Basis for Estimating the MISO Base Case

Although the Base Case in the Supplemental Investigation is similar to the Base Case in the First CB Study, it differs in one respect in that it includes consideration of some elements of the proposed EMT that were unknown when the First CB Study was undertaken, Schedule 21 costs for example. Specifically, the EMT, as modified by the August 6 Order, provides significant detail about several aspects of the new market design, including the duties and responsibilities of MISO, transmission owners (TOs), generation owners, and other market participants; about the process by which TOs and network service customers will receive FTRs and share in FTR revenues; and about how some of the costs of protecting particular groups of MISO participants from congestion and other costs of transitioning to the proposed Day 2 Markets will be resolved.

2.2 PJM Participation: Change Case 1

In this case, the Companies withdraw from MISO and join PJM. Withdrawal from MISO will require the Companies to pay an exit fee, discussed in more detail below.

Under this option, it is assumed that the Companies' network service for native load would not be subject to curtailment to satisfy a capacity shortfall in the PJM-West zone. As stated in the Kentucky Power stipulation, "In the event that FERC proposes mandatory purchases or sales into PJM's market, the Stipulation provides that PJM and the other parties are obligated not to contest AEP's decision to not participate in any such mandatory market... In the event of a transmission emergency, PJM is responsible only for determining the location, quantity and timing of any curtailment. PJM is not responsible for determining or directing the manner in which the load is to be curtailed during an emergency. ... PJM will direct AEP to curtail retail load only after PJM has exercised all other available opportunities to remedy an emergency without curtailing retail load."[7]

Congestion costs in PJM are determined by the differences between source and sink LMPs set in the hourly day-ahead market. Regardless of whether the Companies' decide to self-schedule, they will be subject to congestion costs. The Companies would receive an allocation of FTRs

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[6] The only adjustment to the FTR allocation within the quantitative analysis is made with respect to payouts by MISO to FTR holders. These payouts are assumed to be 5% less than the nominal value of the target FTR allocations due to FTR revenue inadequacy, a problem that has been experienced in PJM. This assumption is also made for the PJM RTO Change Case.

[7] June 2004 Order at 7-8.

intended to hedge their congestion costs. The allocation is assumed to be sufficient to fully hedge the Companies native load customers from congestion costs, with the one exception as noted above under the MISO Base Case description.

The Companies would pay a share of PJM's administration costs as per schedules in the PJM OATT. The Companies may also bear a share of uplift costs that are socialized to all transmission owners.[8]

2.3 SPP Participation: Change Case 2

In this case, the Companies withdraw from MISO and join SPP. Withdrawal from MISO again requires the Companies to pay an exit fee.

The Companies' system would be treated as a separate control area that is dispatched independently of the rest of SPP. At the same time, dispatch of the Companies' generation fleet will most likely be affected by MISO's coordination of generation dispatch and management of congestion in real time regardless of the Companies' membership in SPP.

SPP currently performs some consolidated services and functions under Orders No. 888, 889, and 2000, particularly reliability coordination and regional tariff administration and OASIS administration. SPP is currently implementing regional transaction scheduling and a market settlement system as required by Order No. 2000.

SPP's longer-term plan to implement features of Order 2000 required of an RTO involves a three-phase process over the period 2004 to 2006. In phase one, SPP proposes to eliminate rate pancaking within the SPP footprint and to introduce an energy imbalance market by the close of 2004, as well as introduce market monitoring and market power mitigation.[9] Phase two involves the implementation of a congestion management system. This system may entail the use of locational pricing, but the form of that system has not been determined yet. In phase three, SPP plans to introduce a capacity ancillary service market in 2006. Because of the lack of an electrical interconnection between SPP and the Companies' system at this time, many features to be implemented in this three-phase program will not directly affect the Companies, even if they were members of SPP. For example, the development of the capacity ancillary service market would have no effect on the Companies. SPP's current long-term implementation plan may lead to the administration of day-ahead and real-time energy spot markets and markets for reserve services, but it is not expected to be implemented within the study period.

Nevertheless, the Companies would pay a share of SPP's implementation and administration costs according to formulas in the schedules as defined in the SPP OATT.

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[8] Uplift costs could not be computed for PJM and therefore were not included in the quantitative analysis.

[9] Phase one has three increments: introduction of imbalance measurement for settlements; enhanced security through daily communications of capacity and resource plans, and real-time communication of interchange values between SPP and the control areas to enhance system security; and implementation of a real-time imbalance market by the close of 2004, along with market monitoring and market power mitigation. See "Market Overview," SPP, PowerPoint slide show, January 2004.

2.4 TORC Option: Change Case 3

To operate as a TORC, the Companies must withdraw from MISO and pay an exit fee. The Companies would then operate their generation and transmission assets more or less independently of MISO, except that they could enter into some form of coordination agreement with MISO to respect its authority as reliability and scheduling coordinator for the MISO region and possibly with respect to acting in that capacity for the Companies. Alternatively, the Companies could enter into some coordination agreement with some other entity, such as TVA, PJM or SPP to provide the required Reliability Coordination services.

Under this case, the Companies would dispatch their own generation resources to meet native load and wholesale requirements obligations, and would function as the control area operator to address congestion on their system. The Companies would provide open access transmission service under an Order No. 888 *pro forma* tariff approved by FERC, and would take responsibility for those planning and operational functions that a control area operator would be required to fulfill to satisfy reliability and security standards imposed by the state, NERC, ECAR, and/or FERC subject to rules of a Reliability Authority and Coordinator. Of course, the Companies would be answerable to some NERC reliability authority and would enter into a coordination agreement with some entity that would be a designated NERC Reliability Authority (e.g., MISO, TVA, or some other entity).

The Companies are assumed to buy and sell energy with the same entities (or similar entities) as they have in the past, including entities inside of MISO as well as outside of MISO (e.g., TVA). Purchases of economy energy from and off-system energy sales to entities within MISO would be made at the MISO-designated external interface between the Companies and MISO or the Companies could choose to participate in the day-ahead and real-time markets in MISO or PJM.

3. Conclusions from the First Cost-Benefit Study

The First CB Study examined three RTO options and one non-RTO option: continued MISO membership; membership in the SeTrans RTO; creation of a statewide Independent System Operator (Statewide ISO); and Standalone (or TORC) option. The First CB Study concluded that the TORC option was, on the basis of the available quantitative evidence and a qualitative assessment of hard-to-quantify factors, economically superior to all of the RTO options. It also concluded that, if an RTO option was to be chosen from among the three options evaluated, the MISO RTO membership was economically preferred.

The First CB Study found that, relative to continued MISO membership, the present value to 2003 of the net benefit of the TORC option was $30.2 million (PV to 2003, 2005-2010). In the Companies' rebuttal testimony, the present value of this net benefit was revised upward to $47.1 million (PV to 2003, 2005-2010) to reflect additional information supplied by MISO in its direct testimony.[10]

[10] See *Rebuttal Testimony of Mathew J. Morey On Behalf of Louisville Gas and Electric Company and Kentucky Utilities Company*, February 9, 2004 in *Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266, at 7.

4. Conclusions of the Supplemental Investigation

Quantifying particular costs and revenues associated with any of the four cases considered in this investigation is challenging. With any study of this kind, there is a great deal of uncertainty about what the future outcomes will be in each of the cost and revenue categories that make up an estimate of the net cost or net revenue of a particular option and that ultimately determine the estimate of the net cost or net benefit of the one option compared to another. Naturally, assumptions were made to accomplish this quantification, and hence, with any such study there is a margin of error that enters into the estimates.

To address the difficulty in estimating the costs and benefits of various options, studies of this sort typically resort to scenario analysis on key variables (i.e., factors that drive the estimates of costs or benefits) so that reasonable bounds on the range of cost and benefit outcomes can be established. The application of scenario analysis is designed to allow improved decision-making by allowing more complete consideration of outcomes and their implications. In particular, scenario analysis is a tool for assessing the risks of a particular course of action.

The heart of the short-term benefits of RTO membership under a Day 2 Market is believed to be savings in production costs, power purchases and increased off-system sales volumes and perhaps net margins. The principal barrier to achieving similar savings and benefits under the TORC option is transmission: limits on transmission transfer capability, limits on efficient utilization of the transmission system[11] and wheeling rates.[12] Another factor that could impact net margins on off-system sales could be the market-clearing price.

The core of the Supplemental Investigation examines, through production cost modeling conducted by the Companies' staff, the impacts of changes in assumptions about three key factors: transfer limits as a proxy for limits on efficient utilization of the grid, wheelng rates and market-clearing prices. Thus, the TORC option is examined under three scenarios: a baseline scenario (TORC Baseline Scenario) involving assumptions that are believed to reflect what is most likely to happen with transfer capabilities and wheeling rates; and two scenarios that examine the sensitivity of the results to changes in key assumptions in the production cost modeling.

The two sensitivity scenarios are called the TORC Low-Transfer Scenario and the TORC High-Transfer Scenario. The Low-Transfer Scenario assumes that transmission transfer limits are lower than in the TORC Baseline Scenario.[13] Lower transfer limits for the transmission system in this scenario were intended to capture the notion that the transmission system could not be utilized to its fullest extent by the Companies as a result of the application of TLRs as the means of managing congestion problems under the TORC option.

[11] Such limits might be imposed, for example, by institutional rules such as NERC's Transmission Loading Relief (TLR) procedures.

[12] Transmission transfer limits have been found in other studies to be significant because these limits set the bounds on the volume of trade among and within regions, which in turn affects off-system sales costs and revenues and power purchase costs and costs of own generation to serve native load.

[13] The production cost modeling for the TORC Baseline Scenario has been used in the SPP RTO Case, so that the SPP RTO Case also could be characterized in terms of Low-Transfer, High-Transfer and Baseline Scenarios.

The High-Transfer Scenario assumes that the transmission transfer limits are the same in the TORC Case, the MISO Base Case, and the PJM RTO Case. In addition, the High-Transfer Scenario assumes that the wheeling rates are the same in these three cases.

Other scenarios could have been examined by varying assumptions about other quantifiable factors in this study. For example, it might have been assumed that the administrative charges in the RTO cases would be higher or that transmission revenues would be higher under the TORC option. However, it was believed that such sensitivities to the scenario studies would have resulted in net costs of the RTO options that were contained within the bounds set by these three scenarios for the TORC option.

The results of the quantitative analysis of costs and benefits are summarized in Tables 1 and 2. Table 1 shows the total costs and revenue values under each option. Table 2 indicates the differences between the present values of the RTO options and the TORC Baseline Scenario. The results are summarized in more detail in Section 9 for all RTO and non-RTO options, including the results for the TORC Low-Transfer Scenario and the TORC High-Transfer Scenario.

To summarize briefly, the results of the quantitative analysis lead to the following conclusions (where all dollar figures are present values in 2003 of costs and benefits incurred over the study period 2005-2010):

- The TORC option remains the economically superior option when compared with any RTO option.[14]
- If the Companies must be a member of an RTO, the SPP RTO option is economically superior.[15]
- Under the TORC Baseline Scenario, for the MISO membership option to be beneficial to Kentucky retail customers, the net non-quantifiable benefits of the MISO RTO option would have to exceed \$50 million, excluding the exit fee. In other words, the net cost of the MISO RTO option is roughly \$50 million.[16]
- Under the TORC Low-Transfer Scenario, for the MISO RTO option to be beneficial to Kentucky retail customers, over the study period, the sum of the benefits for the MISO Base Case associated with net non-quantifiable factors, at a minimum would have to exceed \$29 million, excluding the exit fee. In other words, the net cost of the MISO RTO option is roughly \$29 million at a minimum.[17]
- Under the TORC High-Transfer Scenario, for the MISO membership option to be beneficial to Kentucky retail customers, the net non-quantifiable benefits of the MISO option would have to exceed \$60 million, excluding the exit fee. In other words, the net cost of the MISO RTO option is roughly \$60 million, excluding the exit fee.[18]

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[14] See column 5 of Table 1 and column 4 of Table 2.

[15] See column 3 of Table 2.

[16] See column 5 of Table 1 and column 4 of Table 2.

[17] See column 5 of Table 2.

[18] See column 6 of Table 2.

Thus, the results of the Supplemental Investigation imply that the MISO RTO option could cost the Companies and Kentucky retail customers between $29 million and $60 million (PV to 2003, 2005-2010), excluding the exit fee, over the study period. If the exit fee is considered, the MISO RTO option is estimated to cost between $4 million and $35 million (PV to 2003) over the study period. This range encompasses the cost of the MISO RTO option estimated in the First CB Study. The best estimate is a value within this range in the neighborhood of $30 million (PV to 2003) in savings for the Company and Kentucky retail customers over the period 2005-2010. Since the study period considered in this investigation is short, the present value of the savings would be much larger if the study period were extended to a ten- to fifteen-year period.[19]

Table 1. Present Value of Costs and Revenues for RTO and Non-RTO Options

(Positive numbers are costs; Negative numbers are revenues)

(all numbers are PV to 2003 for the period 2005-2010)[20]

Category	MISO RTO Base Case	PJM RTO Case	SPP RTO Case	TORC Baseline Case
Administrative Costs	65.56	75.59	30.47	-
Operations Costs				
A&G Costs Associated with RTO Membership Status	12.40	12.40	8.02	8.02
Generation Costs				
Native Load	3,692.30	3,692.30	3,691.21	3,691.21
Off-system Sales	491.30	491.30	488.19	488.19
Transmission System Operation Costs	-	-	-	2.48
Transmission Usage Costs	103.16	103.16	9.45	9.45
Uplift Charges	6.09	-	-	-
Legal, Regulatory & Transaction Costs	3.78	3.78	2.83	1.89
Total Costs	4,374.59	4,403.33	4,254.98	4,226.05
Revenues				
Transmission Revenues	(46.82)	(46.82)	(18.78)	(18.78)
Off-system Sales Revenue	(728.60)	(728.60)	(717.69)	(717.69)
FTR Revenues	(83.54)	(85.13)	-	-
Total Revenues	(858.96)	(860.54)	(736.47)	(736.47)
Net Recurring Cost	3,515.63	3,517.98	3,493.71	3,464.78
Non-recurring Cost (Exit Fee)	-	24.81	24.81	24.81
Years to Break Even Point	NA	NA	4-5	1-2

[19] If the saving achieved in 2010 for the TORC Baseline Scenario relative to the MISO Base Case was assumed to remain constant for the years 2011 to 2019, the present value of the total savings over the period 2005 to 2019 would be $63.5 million (PV to 2003, 2005-2019), including the exit fee, and $88.0 million (PV to 2003, 2005-2010) excluding the exit fee.

[20] The discount rate used is 7%.

Table 2 Differences Among the Present Values of RTO and Non-RTO Options
(Positive numbers are net costs; Negative numbers are benefits)
(all numbers are PV to 2003 for the period 2005-2010)

Category	MISO Base Case minus PJM Case	MISO Base Case minus SPP Case	MISO Base Case minus TORC Baseline	MISO Base Case minus TORC Low-Transfer	MISO Base Case minus TORC High-Transfer
Administrative Costs	(10.03)	35.09	65.56	65.56	65.56
Operations Costs			0.00		
A&G Costs Associated with RTO Membership Status	-	4.38	4.38	4.38	4.38
Generation Costs			0.00		
Native Load	-	1.09	1.09	3.55	0.40
Off-system Sales	-	3.11	3.11	41.45	0.84
Transmission System Operation Costs	-	-	(2.48)	(2.48)	(2.48)
Transmission Usage Costs	-	93.71	93.71	93.71	92.93
Uplift Charges	6.09	6.09	6.09	6.09	6.09
Legal, Regulatory & Transaction Costs	-	0.94	1.89	1.89	1.89
Total Costs	(28.75)	119.61	148.53	189.34	144.80
			0.00		
Revenues			0.00		
Transmission Revenues	-	(28.04)	(28.04)	(28.04)	(28.04)
Off-system Sales Revenue	-	(10.91)	(10.91)	(73.84)	(709.82)
FTRs	1.58	(83.54)	(83.54)	(83.54)	(83.54)
Total Revenues	1.58	(122.49)	(122.49)	(185.42)	(109.72)
Difference in Net Recurring Cost	(2.35)	21.92	50.85	28.73	59.90
Difference in Non-Recurring Cost (Exit Fee)	(24.81)	(24.81)	(24.81)	(24.81)	(24.81)
Years to Break Even Point	NA	4-5	1-2	3-4	1-2

5. Equity Considerations

Cost-benefit studies of RTOs typically evaluate the benefits and costs of implementing a regional bid-based security constrained economic dispatch (real-time) energy spot market from the perspective of the region as a whole.[21] These studies take a societal view and present estimates of the overall quantifiable costs and benefits – that is, the aggregate welfare impacts. This is an appropriate perspective when viewed from the position of an RTO in examining the proposed market and institutional changes.

[21] Such studies include those conducted by MISO in this proceeding and in other proceedings before FERC, as well as studies by various independent consultants (e.g., the study conducted by Charles River Associates, Inc. at the request of the Southeastern Association of Regulatory Utility Commissioners (SEARUC), "The Benefits and Costs of Regional Transmission Organizations and Standard Market Design (SMD) in the Southeast," November 6, 2002).

However, such a perspective masks many of the inherent real problems with creating RTOs, creating spot energy markets, and converting property rights associated with transmission use from physical to financial instruments. First, the regional studies seldom consider the full range of transaction costs that accompany these changes – the costs borne by the market participants to adjust to significant institutional changes that include interfacing with the RTO, legal representations, and endless numbers of committee meetings to hammer out operating protocols that are both workable and acceptable to all market participants.

Second, studies taking a regional perspective do not examine the nature of the distribution of the costs and benefits among various groups of market participants. Finally, such perspectives do not assess the impacts of changes in risks faced by individual market participants that arise with changes in the structure and operation of the wholesale and retail markets and the introduction of new institutions to facilitate wholesale market trading and satisfy regional reliability obligations, such as will be brought about by the introduction of the day-ahead and real-time energy and capacity markets under MISO's EMT and MISO's full assumption of responsibilities as the Regional Reliability Authority. The costs and the risks borne by individual market participants will vary depending upon how power system conditions affect the locational values of their resources and load obligations. Thus, the allocation among participants of benefits relative to costs will vary: some parties can expect to receive a larger share of the benefits while some parties can expect to see a larger share of the costs.

While the various studies conducted by MISO in the past suggest that the overall social welfare of the region will be increased by a move to this new structure and market arrangement, it is unlikely that all individuals or groups of market participants within the region are made uniformly better off. Those members of MISO who have average production costs that are lower than the MISO regional average, such as LG&E/KU, likely will not see significant reductions in net power procurement costs or net transmission costs. By the same token, such entities will definitely see increases in costs associated with administration charges and greater risk that the costs of congestion will be higher under MISO's implementation of an LMP-based congestion management system.

6. Principal Drivers of Benefit and Cost Differences Across RTO and Non-RTO Options

This section discusses the main categories of costs and benefits that could be quantified, including discussion of some categories for which there is not enough information to enable an assumption about differences across the cases considered.[22] This investigation attempts to quantify the main categories of benefits, typically characterized as revenues, and the main categories of costs that are likely to vary across RTOs and between RTOs and the operation of a vertically integrated utility as a TORC system. The list of principal drivers that would be included in an ideal quantitative analysis extends well beyond what can be realistically captured in a typical cost benefit study. So many factors simply cannot be quantified, in particular for the MISO RTO case because the Day 2 Market has not been implemented. Despite the increased clarity regarding the EMT, there remains tremendous uncertainty about the actual costs that will

[22] The fact that a category is included in this section but does not appear in the quantitative analysis should not be taken as a sign that we believe that it will not make a difference in the actual outcomes.

be incurred by MISO in administering the Day 2 Markets under the EMT, costs that will be borne by transmission owning members. If the experiences of other RTOs upon startup of their Day 2 Markets are any indication, various cost categories could be higher than have been assumed in this investigation.[23]

For example, MISO's RTO administration costs could increase beyond current projections, if the evidence from the experiences of other RTOs, such as PJM, is any indication. Since 2000, total U.S. RTO operating expenses have increased by 143%, and are growing at an annualized rate of 20% per year, largely due to increases in operational size and scope. Although some RTOs have grown faster than others, all RTOs display a significant upward trend in costs compared to the rate of inflation. MISO has experienced the most rapid growth in expenses, with a 500% increase over the past four years (from $34 million in 2001 to a budgeted $210 million in 2004).[24] PJM has experienced a similar increase, but over a longer period of time. PJM had $21.4 million in operating expenses in 1997, and expects to spend $215 million in 2004.

6.1 Changes in Net Power Procurement Costs

"Net power procurement costs" include the Companies' costs of producing power from their own generation fleet, plus the costs of purchasing power from other generating firms, minus the revenues that the Companies receive from wholesale (off-system) sales.

In principle, RTO membership should allow the Companies to reduce their net power procurement costs because RTOs have communications and software that may enable them to find some additional cost-reducing trades that might not be found through conventional bilateral procedures. From a social perspective, the cost reductions are generally in the fuel costs of producing electric energy, but they may also be in the fuel costs associated with generator start-up and shut-down as well as in labor and other operating costs.

From the Companies' perspective, the net cost reductions allowed by RTOs will appear as: a) incremental wholesale purchases that can substitute for some incrementally more expensive purchases that the Companies would otherwise find on their own; b) wholesale purchases that can substitute for the more expensive generation that the Companies' would otherwise dispatch; c) incremental wholesale sales that can substitute for the lower-priced sales that the Companies would otherwise find on their own; and d) wholesale sales that have higher prices than the cost of the generation that the Companies have available to serve those sales.

The Companies RTO membership within a Day 2 Market is not expected to provide large reductions in net power procurement costs. However, it may make it easier for the Companies to find cost-reducing trades than before the existence of a Day 2 Market.

6.2 Changes in the Costs of Transmission Losses

Under the TORC option, the Companies' costs of transmission losses have two components. First, they will pay the RTOs' loss charges for transmission service outside of the Companies'

[23] For example, administration costs could increase beyond current projections or uplift costs could be higher than projected.

[24] See Midwest Independent Transmission System Operator, Inc., *2001 MISO Annual Report* and *Updated 2004 Budget Presentation*, 3/18/2004.

service territories. Second, they will pay for losses for transmission service inside the Companies service territories, less any revenues for losses that they receive from other wholesale entities that use the Companies' transmission system.

Regardless of whether the Companies are members of any RTO, they will pay the RTO charges for losses for transmission service outside of the Companies' service territories. RTO membership will therefore only affect charges that the Companies pay for losses for transmission service inside the Companies' service territories.

Under the MISO EMT, LMPs will reflect marginal transmission losses, so that the cost of each transaction will reflect the marginal cost of losses between sink and source locations. Because marginal losses tend to be nearly double of average losses, MISO's charges based upon marginal losses will generally exceed the average cost of the losses. MISO intends to allocate the excess to "loss pools" for various geographic areas, and to rebate the excess of each loss pool to market participants according to their relative load shares in each pool. The average customer will receive a rebate approaching half of their payments for marginal transmission losses; but for some customers the rebate may be substantially more or less than this average. Therefore, the loss-related cost of MISO membership relative to the TORC option will depend upon whether transmission service inside the Companies' service territories has an average cost that is greater than or less than the marginal cost of losses net of the rebate. There is no basis upon which to make an assumption that the Companies would receive less or more in a rebate than half their marginal loss payments. Therefore, the assumption was made that the loss cost rebate was one half of the payments.

Transmission loss costs in PJM are computed on the basis of average losses, and are applied equally to all transactions. PJM intends to move toward marginal cost-based pricing of losses at some future date. Under the present pricing arrangement, however, the cost of PJM membership relative to the TORC option will depend upon whether transmission service inside the Companies' service territories has an average cost that is greater than or less than the average cost of losses throughout PJM. This fact is unknown. Therefore, loss costs were assumed to be equal to those in the TORC Change Case.

We assume that under the SPP Change Case the Companies cover the costs of their own average losses, as is the case under the TORC Change Case. The costs of transmission losses under the SPP Change Case are therefore identical with these costs under the TORC option.

While it is not likely that the net loss costs will be identical in all the cases, there was no basis upon which to assume they differed, and consequently loss costs were assumed not to vary across the four cases.

6.3 Changes in the Net Costs of Transmission Access

Under the TORC option, the Companies' net costs of transmission access have the following components:

a. capital and operating costs of the transmission facilities that the Companies own; plus
b. payments of the RTO transmission access charges and congestion charges for transmission service outside of the Companies' service territories; less

c. revenues received from other wholesale entities for use of the Companies' transmission system.

Under the MISO and PJM RTO options, the Companies net costs of transmission access have the following components:

d. capital and operating costs of the transmission facilities that the Companies own; plus
e. payments of the RTO transmission access charges and congestion charges for transmission service both inside and outside of the Companies' service territories; less
f. the value of FTRs;[25] less
g. revenues received from other wholesale entities for use of the Companies' transmission system.

Items a and d are not necessarily identical, as pooling of resources and differences in the use of facilities may allow lower costs in the RTO cases than in the TORC case. Items c and g are surely different, as the basis for determining these revenues will be very different in the RTO and TORC cases.

Because there is no direct electrical interconnection between the Companies and SPP, and because SPP is not planning on introducing a congestion management system based on LMPs during the study period, we assume that the Companies' transmission access costs (including congestion costs) will be kept separate from the rest of SPP. Therefore, there would be no difference in the net transmission access costs for the SPP and TORC option.

6.3.1 Capital and Operating Costs of the Companies' Transmission Facilities

One conceivable difference in the long-term between operating within the context of an RTO compared to operating a TORC system could be the amount of investment in transmission by the Companies to address transmission-related problems on the local system or to enable own generation to have greater access to native load or wholesale customers. The investment issue has several dimensions. First, the long-term expansion planning conducted by the RTOs might lead to situations in which the RTO finds regional solutions to local transmission problems. Consequently, the Companies may invest less as an RTO member than they would otherwise have to invest as a TORC utility to ensure a reliable and adequate delivery system. However, if the transmission investment made by others does truly solve a regional problem, the costs of that investment could be spread across all RTO members as discussed below.

Second, regional solutions identified by the RTO may require the Companies to invest in transmission as an RTO member to a greater degree than they would under the TORC option. MISO has the authority to mandate transmission investment by a transmission owning member, but it is not clear how the costs of that investment would be treated. The PJM Operating Agreement also requires transmission owners to construct, own, and finance transmission enhancements or expansions within their control areas subject to applicable law or regulation, right-of-way acquisition, and the right to recover reasonably incurred costs plus a reasonable return on investment. Consequently, PJM can, subject to these conditions, require transmission owners to construct transmission facilities that are needed for reliability or that provide cost-

[25] The annual value of FTRs is expected to be positive, but it is important to note that an FTR obligation can take on a negative value when the transmission flow is opposite the direction of the FTR held.

effective relief to transmission congestion. In either case, the Companies could be required to build transmission facilities the costs of which could be borne at least in part by the Companies' retail customers. The magnitude of those costs and the share borne by native load customers of those costs is unknown.

The Companies could bear a share of the costs of transmission investment made by others under two circumstances. First, if the RTO adopts postage stamp pricing for transmission access. Second, if there is some provision in the RTO's OATT for recovering a portion of those costs through an uplift charge justified on the grounds that the investment provides reliability benefits to all market participants. MISO currently has zonal (i.e., license plate) pricing for transmission access and a move to postage stamp pricing is very uncertain. PJM also has zonal pricing. But there are proposals to move by 2008 to a different rate design for pricing transmission access in the MISO-PJM region.[26]

6.3.2 Payments for RTO Access and Congestion Charges

As a member of MISO, the Companies will make payments associated with MISO providing additional congestion cost hedging protection to those entities that may not be fully protected under the proposed allocation of "virtual counterflow FTRs."

Under all options, transmission payments made by the Companies for Network Integration Transmission Service (NITS) will be offset by an equal amount in transmission revenues. Transmission payments by the Companies for firm and non-firm Point-to-Point (PTP) service in MISO would be recovered more or less through an allocation set by a *pro rata* share of the revenues MISO receives from transmission users. Payments will also be made under all cases considered for network integration transmission service (NITS) provided to native load customers based on the Companies' zonal rates. The payments for NITS are not expected to vary across any of the cases.

6.3.3 The Value of FTRs

The extent to which FTRs hedge against congestion risk depends upon two major factors. First and most important is the quantity of FTRs that a market participant receives relative to the quantity that they want. The second factor is the extent to which the RTO is able to honor the nominal value of the FTRs that it issues.

For example, suppose that an entity wants 200 MW of FTRs but the RTO allocates only 100 MW of FTRs to that entity. This would occur if the RTO found that the physical capacity of the transmission system was capable of providing a physical hedge for only half of the requested FTRs. In other words, the aggregate FTR requests of all market participants may not be simultaneously feasible. The entity that wants 200 MW of FTRs would thus be issued what are nominally 100 MW of FTRs, which would cover only half of its expected congestion costs, thus exposing it to considerable congestion price risk. But the experience of PJM has been that actual FTR values (i.e., payouts) have averaged about 95% of their nominal values; in other words, PJM has experienced a revenue shortfall in its FTR payouts. In this situation, the market

[26] See "Unified Plan for Long-term Transmission Pricing," August 27, 2004, http://www.pjm.com/committees/stakeholders/long-term-pricing-meetings.html.

participant would expect to receive payment to cover its congestion costs equivalent to holding 95 MW of FTRs, thus losing the value of the last 5 MW of the FTR.[27]

This section explains how FTRs are or will be allocated in PJM and in MISO. The Companies may receive different quantities of FTRs under the MISO, and PJM scenarios, largely because MISO and PJM serve different geographic areas and therefore offer FTRs as hedges against congestion on different transmission facilities, but also because of the different allocation methods of the RTOs. However, for purposes of this investigation, we assume that the same number of FTRs will be allocated to the Companies in either RTO case, and the nominal value of those FTRs will be the same.

Furthermore, we assume that, consistent with PJM's past experience, both PJM and MISO will actually pay FTR holders for 95% of the nominal value of FTRs. For simplicity, we also assume that FTRs will be in the form of FTR obligations, not FTR options.[28] This latter assumption is consistent with MISO's present plans, and with the way that the overwhelming majority of FTRs in PJM have in fact been issued.

<u>FTRs Under MISO</u>

The Companies will nominate FTRs under the MISO's proposed EMT on the basis of their providing NITS, for any long-term firm PTP transmission service rights that they possess, and for NITS to native load for generation resources called "designated network resources" (DNRs). Their nomination would yield a direct allocation of FTRs to cover a six-month period. The allocation would take place through a four-tier procedure.[29] The Companies may nominate FTRs in each tier between any eligible points of receipt and delivery. In principle, the Companies should be able to receive a full allocation of nominated FTRs from resources they use to serve baseload.[30] Subject to a simultaneous feasibility test the Companies can request FTRs in order of their perceived expected financial value rather than in order of historical transmission usage.[31] It is assumed that the Companies will do this in PJM as well as in MISO.

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[27] For a discussion of the revenue shortfall problem in PJM, *see* PJM LLC, *State of the Market 2003*, Market Monitoring Unit, March 4, 2004, pp. 155-158.

[28] An FTR obligation provides the FTR holder with credits when the marginal congestion component of the day-ahead LMP at the point of delivery is greater than the LMP at the point of receipt. An FTR obligation imposes on the FTR holder charges (debits) when the marginal congestion component of the day-ahead LMP at the point of delivery is less than the LMP at the point of receipt.

[29] "FTRs can be nominated from Network Resources based on the Forecast Peak Load served under Network Integration Transmission Service and from the points of delivery and receipt in Point-to-Point Transmission Service of annual duration or longer. The maximum quantity eligible for nomination is the sum of these existing entitlements for network service and the total quantity in each point-to-point service. The FTR allocation process takes place over four successive and cumulative tiers. In each tier, a Market Participant is allowed to nominate up to a percentage of its maximum nomination eligibility less the FTRs awarded in the prior tier. The cumulative Tier Factors are: Tier I, 35 percent; Tier II, 50 percent; Tier III, 75 percent; and Tier IV, 100 percent." August 6 Order, at P 143.

[30] Criteria to determine what "baseload" means were not made clear in the EMT.

[31] In other words, the Companies can nominate FTRs that have positive value only and decline to nominate FTRs that have negative value. FTR obligations have negative value when the LMP at the point of delivery is less than the LMP at the point of receipt.

One aspect of FTRs under the EMT as refined by the August 4 Order is that there is greater risk for the Companies in the MISO RTO case. This arises from the fact that the EMT allows market participants to decide not to nominate Counterflow FTRs.[32] This potentially could restrict FTR allocations because the counterflows enable flows on lines; FTRs may have to be pro rationed. In the EMT, MISO proposes a method by which eligible FTRs could be restored. To restore the pro-rationed FTRs, MISO will define Counter Flow FTRs sufficient to make the eligible nominated FTRs simultaneously feasible. MISO will choose the minimal set of Counter Flow FTRs needed for restoration. The Counter Flow FTRs are allocated directly to the market participant that was eligible to nominate them. They will be settled like other FTRs. If the Counterflow FTRs are not allocated directly to the market participant, they may be created and the costs socialized. In either case, the Companies face greater risk of not receiving their full nomination of FTRs as a result. Or, if they do receive it, there is still the possibility that the FTR revenues will fall short of the nominal value and payouts from MISO will be on a *pro rata* basis.

While we have no way of knowing what will happen under the EMT's FTR allocation process, the history in PJM FTR revenue inadequacy leads us to believe that a reasonable assumption is that revenues will be short of target allocations by at least 5%.

FTRs Under PJM

PJM's transmission customers typically have FTRs or revenue rights for proceeds from auctions of FTRs and can utilize these revenue rights as a hedge against transmission congestion costs. Initially, the FTR allocations reflect an assignment of candidate FTRs based on the generation resources that were historically designated to serve the load. All LSEs in the Companies' zone are provided with a *pro rata* amount of MW capacity from each resource based on their proportion of load within the region. Each LSE may request a quantity of FTRs from any of the assigned resources up to its resources capability and to each zone up to their peak load in the zone.

The second stage of the FTR allocation is an iterative allocation process, which consists of four rounds with 25 percent of the system FTR capability allocated in each round. Each round is conducted sequentially with LSEs being given the opportunity to view results of each round prior to submission of FTR requests into the subsequent round. Valid FTR source points in Stage 2 include zones, generators, hubs, and external interface points. In each round, LSEs may request a MW quantity of FTRs for up to 25 percent of their peak load not covered by FTR MW from the initial allocation.

Firm point-to-point transmission customers may also request FTRs during Stage 2. In each round, the customer may request up to 25 percent of the MW of the service being provided between the specified source and sink points of the service. All FTRs must be simultaneously feasible. If all FTR requests made during the annual allocation process are not feasible, FTRs are pro-rationed and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraint.

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[32] "Counter Flow FTRs are defined as eligible base-load FTRs that were either not nominated by a Market Participant or not awarded in the first two tiers, but that if they were assigned would provide counterflow in the FTR model for restoration of other nominated FTRs." August 6 Order, at P 144

After a transition period, the assignment of FTRs within the Companies' zone will convert to an auction process where LSEs will initially receive auction revenue rights (ARRs) in a manner similar to the process described above for the initial assignment of FTRs. This assignment process differs slightly in that the initial allotment of ARRs to an LSE is based on a historical reference period and not on current network loads and resources. In addition, the value of that ARR allocation will be market based, determined by the supply and demand for ARRs.

LSEs can request the 25 percent of the remainder of their needed ARRs in the subsequent four rounds of ARR assignments similar to the process described earlier for the initial assignment of FTRs. The FTR auction process is currently being utilized throughout PJM's pre-expansion footprint.[33] The holders of ARRs can convert those ARRs to FTRs with the same resource and load characteristics; such FTRs are said to be self-scheduled. An LSE that elects to convert the ARRs self-scheduled FTRs becomes a price taker in the ARR auction; that is, self-scheduled FTRs are not able to influence the outcome of the ARR auction.

PJM conducts an annual auction of all FTRs, and conducts monthly auctions of any FTRs not taken in the annual auction and of FTRs offered for sale by their holders. The holders of ARRs receive the proceeds from the annual auction of FTRs.

There is a possibility that the Companies may not receive the full allocation of FTRs they request in each year of the transition period if the request is not simultaneously feasible. However, they can choose in this process to convert ARRs to self-scheduled FTRs. This strategy has proven to be the best approach to hedging congestion in PJM since the revenues generated by the ARR allocation and auction process have not been sufficient to cover congestion costs.

6.3.4 Transmission Revenues

Regardless of RTO membership, the Companies would receive transmission revenues associated with providing NITS and PTP (firm and non-firm) service under an Open Access Transmission Tariff (OATT) self-administered under the TORC option or administered by one of the three RTOs.

Revenues collected by an RTO for schedules 1 through 9 and 11 would be allocated to the Companies on a formula basis (typically allocated according to load ratio shares) including NITS, firm and non-firm PTP service within the RTO footprint, and firm and non-firm PTP service through and out of the RTO footprint (where such through and out rates are still applicable). Under the TORC option, the Companies would receive revenues directly from transmission customers for providing the services under Schedules 1 through 9.

The principal issue under this category centers on whether there is any difference in transmission revenues between and among the various RTO membership and non-RTO options. For NITS, there is not likely to be any difference since the RTO will in effect reimburse the Companies for any payments they make for NITS. Zonal rates for the Companies will be based on the Companies' revenue requirement, which is not expected to change under any RTO option or, for that matter, under the TORC case. With respect to transmission revenues associated with providing PTP service, there is not likely to be a significant difference among the several options since the major user of the Companies' grid will be its own generation division in making off-

[33] Pre-expansion is defined as the current period prior to AEP, ComEd, DP&L and Dominion joining PJM.

system sales into the MISO-PJM combined market or outside of that footprint, predominately to TVA.

Thus, for purposes of this investigation, we have assumed that for those portions of the transmission revenues that are likely to be at all affected by the Companies' RTO status, there is no difference between the transmission revenues in the MISO Base Case and the PJM Change Case. In the TORC Change Case and the SPP Change Case we have assumed that the only transmission revenues that will be received correspond to grandfathered transmission contracts

6.4 Changes in Reliability

It has been argued by some that RTOs can improve reliability for at least two reasons. First, because RTOs dispatch a wider array of resources than are available to any one market participant, they have a wider range of options for responding to potential reliability threats. Second, they have communications and software systems that allow them to see a much broader picture of the system than a local operator and therefore to identify threats to reliability more easily than would relatively more independent control area operators. Through rapid communications between the RTO and market participants, it is possible for many individual market participants who see only a part of the power system.

There are, however, at least four reasons to believe that reliability might be worse under RTOs than under conventional reliability arrangements. First, during a transition period, RTO operators need to learn to deal with a new aggregated power system. This is especially true for MISO, in which trading and dispatch arrangements will change radically with the implementation of the EMT. Second, again for a transition period, there may be a lack of the joint operating agreements that are needed to get various parties to cooperate with the RTO's system operators. Third, there is a question as to whether a very large power system can be dispatched as effectively as several smaller power systems: can system operators presiding over a large power system know the detailed workings of the power system as well as operators who preside over smaller pieces of that system? This question is especially pertinent to MISO, which will coordinate the actions of dozens of control areas over a huge geographic region and which, in August 2003, was involved in the largest power outage in U.S. history. Finally, an RTO's freedom of action will sometimes be limited by agreements that constrain the RTO's ability to dispatch resources under certain conditions.[34]

As a practical matter, only MISO membership can materially affect reliability in the Companies' service territories relative to the TORC case: PJM's interconnections with the Companies' service territories are too weak to make much difference; and SPP's interconnections are non-existent.

But the reality is that an RTO cannot fix what is not broken. The Companies have a long history of meeting and exceeding NERC reliability criteria, and of providing highly reliable service to their customers. An RTO will not improve upon this record. At best, an RTO will continue to provide the same level of reliability as the Companies have provided in the past. The hope is that the RTO can provide reliable service at lower cost due to economies of scope and scale because

[34] For example, the stipulation reached in the Kentucky Power case imposes this kind of limitation on PJM's coordination of the Kentucky Power generator units. A similar stipulation was reached between the Virginia State Corporation Commission and AEP regarding the generation units in its Virginia service territory.

the RTO controls a wider variety of resources than are available to the Companies. However, the reality may be that costs on a per unit basis increase since the Companies have not been in a position to eliminate any of the costs associated with the transmission system operations pertaining to reliability.

6.5 Changes in Investment Costs

Through their long-term regional planning and coordination procedures, RTO membership might allow market participants to reduce the aggregate cost of their transmission and generation investments. This could occur because the RTO would provide a forum in which market participants could exchange information about regional investment needs and about their investment plans. The RTO planning and coordination process might therefore allow the Companies to avoid making some investments in transmission or generation facilities to satisfy load growth or to solve local (i.e., control area) transmission problems whose real source lies outside the Companies' control zone.

The difficult-to-quantify long-term benefits of the regional planning and coordination process come at the cost of RTO membership dues. Thus, a question remains as to whether these benefits exceed that portion of the costs associated with membership that can be deemed attributable to the RTO performing these functions.

6.6 Differences in Administration and Implementation Costs

For all RTO options, the Companies will incur costs associated with RTO administration charges. For the MISO and SPP options, there are also implementation (i.e., startup costs or capital costs) that will recovered through schedule fees. Under the TORC option, the Companies would pay no market implementation and administration fees.

Administration and implementation charges under the MISO RTO option have been discussed at length in the First CB Study.[35] The values of these charges for the Companies have been updated by the most recent MISO projections of these charges.[36]

For the PJM, SPP, and TORC options, the Companies must pay an exit fee that amounts to an "upfront" payment of the Companies' pro rata share of the unamortized capital costs associated with startup and implementation of the MISO RTO.

When the estimated exit fee payment is included in the net cost estimates of the alternative options, it reduces the Net Cost of the MISO RTO option by about $25 million (PV to 2003). However, the study period, defined by the Commission's order in 2003, is shorter than would typically be used in a study of this kind or in a long-range business planning process. Thus, the impression that may be conveyed from the quantitative analysis is that the savings from the alternative options are not overwhelmingly large. However, it must be kept in mind that if the Companies were to exit MISO and pursue an alternative, the savings from that move would continue beyond the end of the study period for many years. For example, if the study period had been extended to 2019, under an assumption that the net cost of the MISO RTO option relative to the TORC Baseline option in 2010 was assumed to prevail for the period 2011 to 2019 (a fifteen

[35] See First CB Study, Section 3.10, at 41-44.

[36] Based on Midwest Independent Transmission System Operator, Inc., "Responses of Midwest Independent Transmission System Operator, Inc. to the LG&E/KU 8/1/804 Data Requests," Item No. 8, September 8, 2004.

year study period), the Net Cost of the MISO RTO option would grow to over $63 million (PV to 2003), which includes payment of the exit fee.

6.7 Differences in Legal, Regulatory and Transaction Costs

Legal, regulatory, and transaction costs arise from paying the Companies' staffs to participate in numerous RTO meetings, prepare information and proposals in relation to RTO committee work, participate in hearings before state and federal regulatory commissions regarding RTO policy or legal issues, and prepare pleadings regarding changes in RTO policies. Additional costs arise from hiring outside legal counsel for representation before state and federal regulatory agencies regarding RTO policies and practices, and contracting consultants and others to provide technical expertise.

The legal, regulatory, and transaction costs associated with the Companies' membership in an RTO may not vary significantly with the particular RTO. Such costs are estimated by the Companies to average approximately $0.8 million per year. Corresponding costs for the TORC option are estimated to average $0.4 million per year. These estimates have not been changed from the First CB Study.

7. Principal Differences Between the First CB Study and the Supplemental Investigation

A desire to provide the best quantitative and qualitative analysis that could be achieved in a study as far-reaching as this compelled the Companies and Christensen Associates to seek to ensure that the Supplemental Investigation improved upon the previous study. The improvements clarify the differences among the various RTO and non-RTO options and the costs and revenues associated with quantifiable factors Values of many factors are simply unknown, in particular the fine details associated with the MISO's implementation of the Day 2 Market and administration of the EMT. Thus, the Companies and Christensen Associates worked to improve upon the First CB Study through a refinement of the data supporting some of the principal cost and revenue categories. However, the methods used to quantify the costs and benefits of the various options in the Supplemental Investigation in no way depart from the First CB Study in terms of what is the general methodological approach to conducting a cost-benefit study.

7.1 Use of Production Cost and Market Simulations

One means to significantly refine the First CB Study was through the use of production cost modeling and simulation of market-clearing prices in the MISO-PJM region.[37] This part of the Supplemental Investigation was conducted by the Companies' staff and is discussed in detail in testimony filed by the Companies' witness Martyn Gallus. The production cost modeling improved on the estimates of the costs of energy to serve native load, including market purchases, costs and revenues associated with off-system sales, and transmission wheeling costs that were used as inputs to the financial evaluation model.

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[37] But for the short time span the Companies and Christensen Associates were given in the initial proceeding to conduct the study and prepare direct testimony (20 days to do the study), the same production simulation methods would have been applied.

7.2 Use of Scenario Analysis to Reflect Uncertainty in Key Variables

Another improvement over the First CB Study is the use of three scenarios to characterize the uncertainties associated with production costs, off-system sales and transmission costs. The focus on these elements through scenario analysis reflects the belief that the real drivers of any short-term benefits from either the MISO RTO option or the PJM RTO option will come in the areas of production costs, power purchase costs and off-system sales.

7.3 More Refined Data for Some Revenue and Cost Categories

Additional improvements over the First CB Study arise from a more refined set of estimates of various cost categories, such as transmission system operation costs, uplift and administration charges in the MISO Base Case, and, in the TORC Scenarios, changes in the assumption about the size of transmission revenues affected by RTO status.[38] This Supplemental Investigation also includes an estimate of the cost of Reliability Coordination and OASIS services provided by an independent third party.

8. Analytical Approach: Quantification of Principal Drivers

There are two components to the quantitative assessment of the benefits and costs of the RTO membership options and the TORC option. First, a physical model quantifies the costs of energy to serve native load (own generation and market purchases) and the revenues from off-system sales. Second, using the outputs from the physical production modeling as well as information from other sources, a financial evaluation model aggregates all quantifiable costs and revenues for all four options, including the three scenarios examined for the TORC option.

8.1 Model of Physical System Operations

A physical model estimated the economic impacts of a centrally dispatched system on the Companies' generation production costs and on off-system sales. A description of the model and assumptions is contained in an appendix to the direct testimony of Martyn Gallus submitted on behalf of the Companies.[39]

8.2 Model of Financial Effects

The financial evaluation model is composed of an Excel spreadsheet that consolidates quantitative information from the physical model and other sources with assumptions that have bearing on the quantitative assessment. The model converts this information and assumptions into revenues and costs for the Companies under each RTO option and for the TORC option. The treatment of costs and revenues is made consistent with their regulatory treatment under current

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[38] For example, in the TORC Scenarios and the SPP RTO Case, the only transmission revenue assumed for the Companies was from grandfathered transmission service agreements, about which the Companies were reasonably certain. When faced with considerable uncertainty about the size of a revenue or cost in the TORC scenarios and in the SPP RTO Case, assumptions were made that generally favored the MISO Base Case.

[39] See *Supplemental Testimony of Martyn Gallus*, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc., Case No. 2003-00266, filed September 29, 2004.

state and federal regulations. All of the work papers associated with the financial evaluation model are included in this report in Appendix B.

8.2.1 Inputs to the Financial Evaluation

The financial evaluation model used two sets of inputs. One set of inputs includes production costs, off-system sales revenues and transmission revenues from the production cost modeling conducted by the Companies' staff. Another set of inputs involve costs that depend on RTO membership status or on the RTO's version of the Day 2 Market. This latter set of inputs includes variables that can vary significantly across the RTO and non-RTO options and can therefore affect the relative net costs or benefits of the various options. These additional factors include estimates of the following items on the cost side:

- The MISO exit fee (paid to MISO under the all non-MISO Cases),
- RTO administration and implementation costs,
- Administrative and general (A&G) costs that vary with the status of the Companies' RTO membership,[40]
- Transmission usage costs, including payments for transmission wheeling and for congestion costs,
- Uplift charge costs (incurred under RTO options when particular costs incurred by the RTO are not directly assigned and are spread to all market participants or to transmission owners on a some *pro rata* basis), and
- Legal, regulatory and transaction costs (which vary with the Companies' RTO membership status).

Estimates of additional factors included on the revenue side include:

- Transmission revenues, and
- FTR-related revenues (under the MISO and PJM RTO cases only) including payments received to cover the congestion costs incurred while hedged with FTR allocations and additional revenues obtained from annual and monthly FTR auctions allocated to FTR holders on a *pro rata* basis.

8.2.2 Assumptions Made in the Financial Evaluation

Several assumptions were made to implement the financial evaluation based on the outputs from the production cost modeling. Some assumptions were common to all of the cases examined for all years of the study period, while others were specific to a case or the program used to conduct

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[40] The relevant A&G costs are those that the Companies' generation and transmission divisions would incur to ensure that the Companies' system will be smoothly integrated into the MISO Day 2 Market and that the Companies are prepared to participate fully in the Day 2 Market. For example, the Companies have contracted to install over $1 million in new hardware for the Companies' traders to enable the traders to participate in the Day 2 Market.

the analysis. Common assumptions include an inflation rate of 2.5% and a discount rate of 7.0%.[41]

Output from the production cost modeling for the TORC Baseline scenario was used to represent the "physical model" results for the SPP RTO Case: it was assumed that there would be no difference between the Companies' production, power purchases, and off-system sales in those two cases because the Companies are not expected to be electrically integrated with SPP during the study period. The output from the production cost modeling for the RTO scenario was used for both the MISO Base Case and the PJM RTO Case.

8.3 Drivers Not Fully Quantified

The list of factors that could affect the costs and benefits of any one of the options considered in this study is, quite frankly, a very long list. It is much longer than the list of factors that have been quantified. Of course, the First CB Study and the Supplemental Investigation have succeeded in quantifying the main drivers of the costs and benefits so that the general size of the relative gains from choosing one option over another are captured. Nevertheless, many small details that will ultimately matter when the Companies participate in a Day 2 Market go unmeasured.

Among the factors that we have not quantified are:

- Reliability, as represented in the probability of a loss of load in association with a problem on the high-voltage transmission system and then converted to a financial impact.
- Tremendous uncertainties associated MISO's administration of the Day 2 Market.
- The numerous costs hidden in the details of the EMT and how MISO will administer it once the energy markets open in March 2005.
- Uncertainty regarding the growth in RTO operating and administration costs for MISO, PJM or SPP over the study period.[42]
- A shift from the current SPP RTO Day 1 configuration to a Day 2 Market.
- Long-term effects of the Day 2 Market.

The issue of reliability, as defined above, was addressed at great length in the initial proceeding. In the First CB Study, the Companies assumed that there was no difference in the level of reliability of the transmission system between the MISO Base Case and the TORC (i.e., Standalone) Case, and therefore, no change in the financial impact on the Companies or Kentucky retail customers. No evidence presented by MISO in the initial proceeding refuted that assumption. I have maintained that assumption in the Supplemental Investigation for all RTO and non-RTO options.

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[41] The same discount rate of 7.0% was used in the First CB Study, and was based on an estimate of the Companies' weighted average cost of capital.

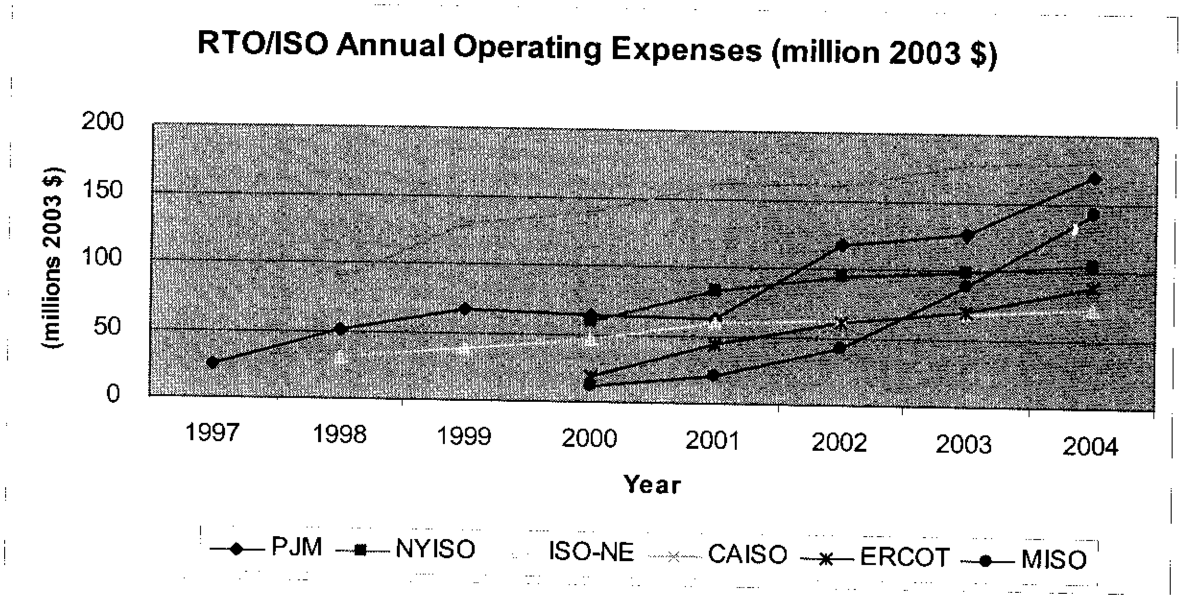
[42] Higher growth rates in administration charges over the study period could have been assumed or explored as a sensitivity case in light of the overwhelming evidence from historical trends.

The assumption that there is no change in the level of reliability achieved under any of the RTO or non-RTO cases considered in the Supplemental Investigation should not be conflated with the issue of what it costs to achieve a given standard of reliability across various RTO and non-RTO options. The Supplemental Investigation assumes that that standard can be met under all options and does quantify the cost of achieving that given standard under each option. The fact that the cost of achieving the standard under the RTO options is bundled within the administration charges the Companies will pay makes it difficult to isolate that cost and make a direct comparison. Nevertheless, a comparison is made indirectly in terms of the Difference in Net Recurring Cost numbers presented in row 19 of Table 2.

Higher growth rates in administration charges over the study period could have been assumed or explored as a sensitivity case in light of the overwhelming evidence from the historical trends. Figure 1 illustrates this trend in terms of the annual operating costs of the ISOs and RTOs.

Figure 1. ISO/RTO Annual Operating Costs

(including Amortization, Depreciation and Interest Expenses in 2003 dollars)[43]



9. Results of the Supplemental Investigation

This section summarizes the results of the physical and financial modeling of quantifiable benefits and costs for the MISO Base Case, the two alternative RTO options (i.e., the PJM RTO Case, the SPP RTO Case), and the TORC Baseline case. This section compares the three alternatives to the MISO Base Case, provides a comparison of the three pairs of RTO options (i.e., MISO vs. PJM, MISO vs. SPP, and PJM vs. SPP), concluding with a summary of results of additional analyses that examine how sensitive the results are to two key assumptions.

Section 9.1 summarizes the results of the quantification of the revenues and the costs associated with each case according to the best available information and the assumptions as discussed in

[43] From Margot Lutzenhiser, "Comparative Analysis of RTO/ISO Operating Costs," Public Power Council, August 17, 2004.

Sections 6 and 7. Section 9.2 summarizes the differences among the net present values of the MISO Base Case and the two RTO cases and the TORC option. Finally, Section 9.3 summarizes the results of the scenario analysis that examines the TORC Low-Transfer Scenario and the TORC High-Transfer cenario, exploring incremental impacts of changing particular key factor assumptions in the physical modeling regarding transmission transfer limits to represent less efficient transmission system utilization under the TORC option and wheeling rates.[44]

9.1 Net Present Value of Costs and Revenues Under the MISO Base Case, the Alternative RTO Options, and the TORC Option

Table 3 summarizes the results of the quantitative analysis of the Base Case and the Alternative RTO and Non-RTO Cases. Results are expressed in terms of the present value to 2003 in millions of dollars.[45] A more detailed summary is presented in Table A.1 in the Appendix A.

Table 3
Present Value of Major Cost and Revenue Categories: All Cases
(millions of dollars; Present Value to 2003, 2005-2010)
(Positive numbers are costs; Negative numbers are revenues)

Category	MISO RTO Base Case	PJM RTO Case	SPP RTO Case	TORC Baseline Case
RTO Administrative Costs	65.56	75.59	30.47	-
Operations Costs				
Generation Costs	12.40	12.40	8.02	8.02
A&G Costs Associated with RTO Membership Status				
Native Load	3,692.30	3,692.30	3,691.21	3,691.21
Off-system Sales	491.30	491.30	488.19	488.19
Transmission System Operation Costs	-	-	-	2.48
Transmission Usage Costs	103.16	103.16	9.45	9.45
Uplift Charges	6.09	-	-	-
Legal, Regulatory & Transaction Costs	3.78	3.78	2.83	1.89
Total Costs	4,374.59	4,403.33	4,254.98	4,226.05
Revenues				
Transmission Revenues	(46.82)	(46.82)	(18.78)	(18.78)
Off-system Sales Revenue	(728.60)	(728.60)	(717.69)	(717.69)
FTRs	(83.54)	(85.13)	-	-
Total Revenues	(858.96)	(860.54)	(736.47)	(736.47)
Net Recurring Cost	3,515.63	3,517.98	3,493.71	3,464.78
Non-recurring Cost (Exit Fee)	-	24.81	24.81	24.81
Years to Break Even Point	NA	NA	4-5	1-2

44 The results physical and financial analysis for each of the individual scenarios are presented on an annualized basis in the Appendix.

45 Revenues, benefits, and net benefits are represented as negative numbers.

The principal differences in the costs among the four cases arise in several categories including: the Exit Fee, RTO administration costs, generation costs of serving native load, including power purchases, generation costs for off-system sales, and transmission usage costs. Revenue differences across three of the four cases arise in every revenue category.

The Net Recurring Cost figures in the line 19 of Table 3 equal the difference between the Total Cost (in row 13) and Total Revenue (in row 18) categories. These figures do not reflect the Exit Fee, which appears in row 20 as Non-recurring Cost (Exit Fee). Row 21 in Table 3 provides an estimate of the number of years it would take to recover the Exit Fee through the savings achieved under the alternative RTO or non-RTO option.

Because the Revenue and Cost categories in Table 3 include only those that depend upon the Companies' RTO decision that we could reasonably quantify, they do not reflect all of the costs and revenues of the Companies, or all of the risks that the Companies will be exposed to as a member of an RTO or as a TORC, or all of the potential benefits that could arise from RTO and non-RTO status. Thus, the Net Recurring Cost values do not constitute an income statement for the Companies or any kind of balance sheet, but are instead useful for the purpose of this analysis, which is making comparisons among the MISO Base Case and the alternative options and any scenarios within a particular option, such as those constructed for the TORC option.

9.2 Differences in the Present Values of the MISO Base Case and the RTO and Non-RTO Alternative Cases

The differences in the present values (PV) across major cost and revenue categories for the MISO Base Case and the three alternatives are presented in Table 4. The same Exit Fee, estimated to be $24.81 million (PV to 2003, 2005-2010) must be paid in all three change cases.

PJM RTO Case

The present value of Administration Costs in the MISO Base Case is about $10 million (PV to 2003) lower than that in PJM RTO Case, primarily because of the rate difference between MISO and PJM; MISO's average rate is about $0.26/MWh and PJM's overall rate is about $0.42/MWh. For the MISO Base Case and the PJM RTO Case, A&G costs have been assumed equal, meaning that the expenditures that the Companies will have to make in the MISO Base Case to participate in the Day 2 Market will be virtually the same for the PJM RTO option.

Generation costs to serve native load, which includes power purchases, are assumed to be the same in the MISO Base Case and the PJM Change Case because the Companies are assumed to be generating the same number of MWh from their generation fleet to serve native load customers regardless of whether they are members of MISO or PJM. This equivalence follows from the assumption made in the production modeling that the Companies would be selling into or buying from the same joint MISO-PJM market regardless of which RTO they joined, in part because of the elimination of regional through and out rates between MISO and PJM at the close of 2004. Therefore, the market prices for power purchases from that joint market are the same in the MISO Base Case and the PJM RTO Case. This also explains why the difference between off-system sales costs and off-system sales revenues in the MISO Base Case and PJM RTO case are both zero: the number of MWh sold off-system into the joint market is the same under each case.

The only difference between the MISO Base Case and PJM RTO Case in the categories of transmission costs and revenues appears under the category of Uplift Charges which in the MISO Base Case were carried forward from the assumption about the uplift charges that the Companies would bear on a *pro rata* basis as members of MISO that was made in the First CB Study and the addition of the estimate of the uplift charges associated with Schedule 21. No similar assumption has been made for the PJM RTO Case since no information was available to determine such a number.

FTR revenues in the PJM RTO Case are slightly higher than in the MISO Base Case for two reasons. First, the assumption made in the First CB Study was that the Companies would receive a *pro rata* share of any MISO FTR auction revenues. This value was assumed to be $2 million per year; the value was carried forward to this investigation in the absence of any other data to change the value. The evidence from the PJM FTR auctions in the 2003/2004 period was used as the basis for a conservative estimate of a *pro rata* share of the revenues for the Companies as a member of PJM.

The net result is that MISO RTO membership is expected to cost the Companies and Kentucky retail customers $27.2 million (PV to 2003, 2005-2010) less over the study period than PJM RTO membership, which makes MISO membership preferable to PJM membership.

SPP RTO Case

The Administration Costs of SPP RTO membership are based on an average rate of about $0.15/MWh, so that the savings to Kentucky retail customers under the SPP RTO option would $35.1 million (PV to 2003) in lower RTO administrative costs over the study period. Legal and regulatory costs are assumed to be slightly lower in the SPP RTO Case than in the MISO Base Case and the PJM RTO Case because of SPP is assumed only involved in a Day 1 market over the entire study period. Other differences between the MISO Base Case and SPP RTO Case are reflective of differences arising in the TORC Baseline Scenario and are captured through the discussion of that case below. It should be noted that for the SPP RTO Case as presented in Table 4, the basis for the production costs is the TORC Baseline Case. Thus, under that production modeling scenario, SPP membership is estimated to cost the Companies and Kentucky retail customers $21.9 million (PV to 2003, 2005-2010) less than the MISO RTO option over the study period, excluding the exit fee payment. If the exit fee payment is included, the SPP RTO would more costly than the MISO RTO option by $2.9 million (PV to 2003, 2005-2010).

It should also be noted that if the study period were extended to fifteen years, rather than the six years as ordered by the Commission, the SPP RTO option would save the Companies and Kentucky retail customers an estimated $35 million (PV to 2003, 2005-2019), including payment of the exit fee.

Table 4
Differences Among the Present Values of the MISO Base Case and the Alternative Cases (millions of dollars; PV to 2003, 2005-2010)
(Positive numbers are relative costs of the MISO Base Case;
Negative numbers are relative benefits of the MISO Base Case)

Category	MISO Base Case minus PJM Case	MISO Base Case minus SPP Case	MISO Base Case minus TORC Baseline Case
RTO Administration Costs	(10.03)	35.09	65.56
Operations Costs			0.00
A&G Costs Associated with RTO Membership Status	-	4.38	4.38
Generation Costs			
Native Load	-	1.09	1.09
Off-system Sales	-	3.11	3.11
Transmission System Operation Costs	-	-	(2.48)
Transmission Usage Costs	-	93.71	93.71
Uplift Charges	6.09	6.09	6.09
Legal, Regulatory & Transaction Costs	-	0.94	1.89
Total Costs	(28.75)	119.61	148.53
Revenues			
Transmission Revenues	-	(28.04)	(28.04)
Off-system Sales Revenue	-	(10.91)	(10.91)
FTRs	1.58	(83.54)	(83.54)
Total Revenues	1.58	(122.49)	(122.49)
Difference in Net Recurring Cost	(2.35)	21.92	50.85
Difference in Non-recurring Cost (Exit Fee)	(24.81)	(24.81)	(24.81)
Years to Break Even Point	NA	4-5	1-2

TORC Baseline Scenario

For the TORC Baseline Scenario, and all scenarios, there would be no RTO Administration Costs, although the Exit Fee is in effect a payment of those unamortized capital costs incurred by MISO in setting up the Day 1 and Day 2 Markets.

Administrative and general (A&G) costs listed in Table 4 above include costs for both generation and transmission. These costs are projected to be lower in all TORC scenarios. These costs were examined in the First CB Study. For the A&G costs on the generation side, the savings of $0.4 million per year under the TORC case was carried forward to this investigation in the absence of any better information about changes in those costs under the TORC option (for all scenarios). For the Transmission A&G costs, a separate category was established for costs of Reliability Authority-Coordinator services, which are expected to average about $0.5 million per year.

There will be additional costs assumed to average $0.4 million per year. Since the First CB Study was conducted, the Companies have found that the $1 million that was assumed would have to be spent for system upgrades and other expenditures under the TORC option is also required spending under the current MISO membership in the Day 1 Markets and in preparing for the Day 2 Market, and would not appear to be a savings achieved under the MISO Base Case. Therefore, the TORC option, for all scenarios, is assumed to have higher combined generation and transmission A&G costs of $0.4 million per year.

Generation costs to serve native load customers and for off-system sales are higher under the MISO Base Case option because the volumes of market purchases and off-system sales are higher when the Companies are members of the MISO RTO under the Day 2 Market than when they are operating under the TORC Baseline Scenario.

Transmission costs are higher in the MISO Base Case than in the TORC Baseline Scenario primarily due to congestion cost payments and wheeling charges for off-system sales by the Companies to TVA.

Off-system sales revenues are higher in the MISO Base Case relative to the TORC Baseline Scenario for two reasons. First, in the MISO Base Case, trade hurdle rates are set to zero for the off-system sales made within the MISO-PJM region but are non-zero for off-system trades in the TORC Baseline Scenario.[46] Higher hurdle rates in the TORC Baseline Scenario make some off-system sales uneconomic at the margin, thus reducing revenues in the TORC Baseline Scenario. Second, to capture the effect of TLRs to address congestion on the utilization of the transmission interties and thereby model the effect on off-system trading, the transmission transfer limits were restricted by about 4.6% in the TORC Baseline Scenario. This also results in reduced trades (off-system sales in particular) at the margin.

Thus, under the TORC Baseline Scenario, the net cost of the MISO RTO option relative to the TORC option is found to be $26.0 million in (PV to 2003, 2005-2010), including the exit fee payment. If the exit fee is excluded from the comparison, the TORC option saves the Companies and Kentucky retail customers $50.9 million (PV to 2003, 2005-2010).

9.3 Alternative Scenarios for the TORC Option

Because of the uncertainty surrounding the actual outcomes of any RTO or non-RTO choice the Companies could make, and the many factors that cannot be quantified by a study of this kind, the most appropriate approach is to estimate a range of the net costs and net benefits through the application of scenario analysis.

Scenario analysis is a process of analysing possible future events by considering alternative possible outcomes (scenarios). The analysis is designed to allow improved decisionmaking by allowing more complete consideration of outcomes and their implications. For example, in economics and finance, a financial institution might attempt to forecast several possible scenarios for the economy (e.g., rapid growth, moderate growth, slow growth) and it might also attempt to forecast financial market returns (for bonds, stocks and cash) in each of those scenarios.[47] The application of scenario analysis is a regular practice in business decision making and in developing business strategies in a competitive environment.

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[46] Refer to the appendix to the Martyn Gallus testimony for the Companies for a discussion of hurdle rate assumptions.

[47] In the more complicated situations, it might also consider subsets of each of the possibilities. It might further seek to assign probabilities to the scenarios (and subsets if any), which we cannot do in this study. Then it will be in a position to consider how to distribute assets between asset types; the institution can also calculate the scenario-weighted expected return (which would indicate the overall attractiveness of the financial environment); an expected

For the investigation at hand, scenario analysis can be accomplished for the TORC option by making assumptions that push key variables in the analysis to reasonable limits and, by so doing, examine a range of possible worlds that plausibly could unfold. This is what has been done to produce two additional scenarios for the TORC option: the TORC Low-Transfer Scenario and the TORC High-Transfer Scenario.

While it would be helpful to be able to assign probabilities to particular scenarios within the range, it is not possible to go that far in a study of this kind. Nevertheless, the range provides a means to assess extremes relative to outcomes more centrally located. The best that may be said qualitatively is that the upper and lower values of the range are less likely than outcomes in the middle of the range, but it would be difficult to speculate as to how much.

These transmission transfer limits set bounds on the production simulation model's volume of trade among and within regions, which in turn can affect off-system sales, sales costs and revenues, power purchase costs, and costs of own generation to serve native load. In addition, a reduction in the transmission transfer limits under the TORC option is intended to capture quantitatively the effect of a reduction in the utilization of the transmission system

To create the TORC Low-Transfer and TORC High-Transfer Scenarios, changes in two factors were examined: transmission transfer limits and wheeling rates. These two factors were believed to be the most significant to determining reasonable bounds on the net costs and net benefits of the Companies' RTO options relative to the TORC option because, in the production cost modeling, they are the two variables that are most likely to affect trades at the margin and, in turn, affect energy costs to serve native load and off-system sales net margins.[48]

From all that has been written about the benefits of a Day 2 Market, the largest benefits in the short term are believed to arise from savings in production costs, purchase power costs and from higher off-system sales volumes and net margins. The principal barriers to achieving an equivalent level of benefits under the TORC option are believed to be related to transmission: transmission transfer limits that may be lower under the TORC option than under the RTO options (i.e., MISO and PJM options), and wheeling rates, which may be higher under the TORC option than under the RTO options.

Thus, three scenarios are defined for the TORC option: the TORC Baseline Scenario, already discussed above; a TORC Low-Transfer Scenario, and a TORC High-Transfer Scenario. The TORC Baseline Scenario, the results of which are discussed above, assumes that the transmission transfer limits are 4.6% lower than the limits in the MISO Base Case and the wheeling rates are \$3/MWh higher than in the MISO Base Case and the PJM RTO Case. The TORC Low-Transfer Scenario assumes that transmission transfer limits are 9.3% lower than the MISO Base and PJM RTO Cases and the wheeling rates are \$3/MWh higher than the MISO Base and PJM RTO Cases.[49] The TORC High-Transfer Scenario assumes that the transmission

cost of the MISO RTO option relative to the TORC option cannot be produced from the scenario analysis conducted in this Supplemental Investigation.

[48] Results obtained in other benefit-cost studies have been shown to be sensitive to assumptions about transmission intertie transfer limits.

[49] The production cost modeling for the TORC Case has been used in the SPP Change Case, so that the SPP Change Case could be characterized in terms of Low-Transfer, High-Transfer, and Baseline Scenarios.

transfer limits and the wheeling rates are the same as those asumed for the MISO Base and PJM RTO Cases.

The point of this scenario analysis is to demonstrate how the net costs of the MISO RTO option relative to the TORC option increase when the wedge between the two options, represented by transmission limits and hurdle (i.e., wheeling) rates, is reduced. And because there is no way of knowing for certain how big a wedge will exist between the two options, particularly if the MISO option is pursued regardless of the quantitative evidence presented in this Supplemental Investigation, it is worth examining what the possibilities are if the conditions the Companies operate under as a TORC entity do not differ much from the MISO RTO or PJM RTO options.

The results of the TORC Baseline, TORC Low-Transfer and the TORC High-Transfer Scenarios are presented in Table 5. The results of the comparison to the MISO Base Case are presented in Table 6 in terms of the differences in the present values.

Columns 2 through 4 of Table 6 reflect the difference between the present values of the costs and revenue categories for the MISO Base Case and each of the three TORC Scenarios. The Net Recurring Cost, the values in row 19 of Table 6, for all three Scenarios imply that the cost of the MISO RTO option relative to the TORC option lies between \$29 and \$60 million (PV to 2003, 2005-2010) if only the recurring (i.e., on-going) operational, administrative, and other costs of each option are considered. With the exit fee included, the TORC option remains the preferred course, as the MISO RTO option is estimated to cost the Companies and Kentucky retail customers between \$4 and \$35 million (PV to 2003, 2005-2010).

The results of this scenario analysis imply that the short-term benefits of the Day 2 Market for the Companies and their customers may not be significant if the barriers to trade are reduced or removed entirely for Companies operating in a TORC configuration. Without those benefits in the MISO Base Case, the benefits from other features of the RTO membership are not likely, in the short run, to offset the costs of membership, which are roughly \$66 million (PV to 2003, 2005-2010).

Table 5 Present Values of the MISO Base Case and Three TORC Scenarios

(millions of dollars; PV to 2003, 2005-2010)
(Positive numbers are costs; Negative numbers are revenues)

Category	MISO Base Case	TORC Baseline Scenario	TORC Low-Transfer Scenario	TORC High-Transfer Scenario
RTO Administrative Costs	65.56	-	-	-
Operations Costs				
A&G Costs Associated with RTO Status	12.40	8.02	8.02	8.02
Generation Costs				
Native Load	3,692.30	3,691.21	3,688.75	3,691.90
Off-system Sales	491.30	488.19	449.86	490.46
Transmission System Operation Costs	-	2.48	2.48	2.48
Transmission Usage Costs	103.16	9.45	9.45	10.23
Uplift Charges	6.09	-	-	-
Legal, Regulatory & Transaction Costs	3.78	1.89	1.89	1.89
Total Costs	4,374.59	4,226.05	4,185.25	4,229.78
Revenues				
Transmission Revenues	(46.82)	(18.78)	(18.78)	(18.78)
Off-system Sales Revenue	(728.60)	(717.69)	(654.76)	(18.78)
FTRs	(83.54)	-	-	-
Total Revenues	(858.96)	(736.47)	(673.54)	(749.24)
Net Recurring Cost	3,515.63	3,464.78	3,486.90	3,455.73
Non-recurring Cost (Exit Fee)	-	24.81	24.81	24.81
Years to Break Even Point	NA	1-2	3-4	1-2

Table 6 Differences Among the Present Values of the Base Case and Three TORC Scenarios (millions of dollars; PV to 2003, 2005-2010) (Positive numbers are costs; Negative numbers are benefits)

Category	MISO Base Case minus TORC Baseline Scenario	MISO Base Case minus TORC Low-Transfer Scenario	MISO Base Case minus TORC High-Transfer Scenario
RTO Administrative Costs	65.56	65.56	65.56
Operations Costs			
A&G Costs Associated with RTO Status	4.38	4.38	4.38
Generation Costs			
Native Load	1.09	3.55	0.40
Off-system Sales	3.11	41.45	0.84
Transmission System Operation Costs	(2.48)	(2.48)	(2.48)
Transmission Usage Costs	93.71	93.71	92.93
Uplift Charges	6.09	6.09	6.09
Legal, Regulatory & Transaction Costs	1.89	1.89	1.89
Total Costs	148.53	189.34	144.80
Revenues			
Transmission Revenues	(28.04)	(28.04)	(28.04)
Off-system Sales Revenue	(10.91)	(73.84)	(709.82)
FTRs	(83.54)	(83.54)	(83.54)
Total Revenues	(122.49)	(185.42)	(109.72)
Difference in Net Recurring Cost	50.85	28.73	59.90
Difference in Non-recurring Cost (Exit Fee)	(24.81)	(24.81)	(24.81)
Years to Break Even Point	1-2	3-4	1-2

10. Conclusions

This Supplemental Investigation has examined the net costs and benefits, to the Companies and to Kentucky retail customers, of two RTO participation options and a TORC option relative to the option of the Companies continuing their MISO membership in the context of a Day 2 Market. The results are based on physical modeling of production costs and regional market-clearing prices, and financial evaluation modeling of production and other costs and revenues that are likely also to vary with the option considered. The analysis leads to the following conclusions:

- The TORC option remains the economically superior option when compared with any RTO option.[50]
- If the Companies must be a member of an RTO, the SPP RTO option is economically superior.[51]

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[50] See column 5 of Table 1 and column 4 of Table 2.

[51] See column 3 of Table 2.

- Under the TORC Baseline Scenario, for the MISO membership option to be beneficial to Kentucky retail customers, the non-quantifiable benefits of the MISO RTO option would have to exceed $50 million, excluding the exit fee. In other words, the net cost of the MISO RTO option is roughly $50 million.[52]
- Under the TORC Low-Transfer Scenario, for the MISO RTO option to be beneficial to Kentucky retail customers, over the study period, the sum of the benefits for the MISO Base Case associated with non-quantifiable factors, at a minimum would have to exceed $29 million, excluding the exit fee. In other words, the net cost of the MISO RTO option is roughly $29 million at a minimum.[53]
- Under the TORC High-Transfer Scenario, for the MISO membership option to be beneficial to Kentucky retail customers, the non-quantifiable benefits of the MISO option would have to exceed $60 million, excluding the exit fee. In other words, the net cost of the MISO RTO option is roughly $60 million, excluding the exit fee.[54]

Thus, the results of the Supplemental Investigation imply that the MISO RTO option could cost the Companies and Kentucky retail customers between $29 million and $60 million (PV to 2003, 2005-2010), excluding the exit fee, over the study period. If the exit fee is considered, the MISO RTO option is estimated to cost between $4 million and $35 million (PV to 2003, 2005-2010) over the study period. This range encompasses the cost of the MISO RTO option estimated in the First CB Study. The best estimate is a value in the middle of this range, in the neighborhood of $30 million (PV to 2003, 2005-2010) in savings for the Company and Kentucky retail customers.

Since the study period considered in this investigation is short, the present value of the savings would be much larger if the study period were extended to a ten- to fifteen-year period. The estimated value of those savings is $63 million (PV to 2003, 2005-2010) including payment of an exit fee, and $88 million (PV to 2003, 2005-2010) excluding the exit fee.

[52] See column 5 of Table 1 and column 4 of Table 2.

[53] See column 5 of Table 2.

[54] See column 6 of Table 2.

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Appendix A

Summary Results for Quantitative Analysis of the MISO Base Case and the Change Cases

Table A.1
Present Value of Revenues and Costs: All Cases
(millions of dollars; present value to 2003, 2005-2010)
(Positive numbers are costs; Negative numbers are revenues)

Category	MISO Base Case	PJM RTO Case	SPP RTO Case	TORC Baseline	TORC Low-Transfer	TORC High-Transfer
Administrative Costs						
Implementation & Administration Charges	64.79	75.59	30.44	-	-	-
Ancillary Services Market Administration Charges	0.89	-	-	-	-	-
Other Administrative Costs	-	-	0.03	-	-	-
Subtotal	65.56	75.59	30.47	-	-	-
Operations Costs						
Generation Costs						
A&G Costs Associated with RTO Status	6.20	6.20	4.21	4.21	4.21	4.21
Native Load						
Fuel Costs	2,752.05	2,752.05	2,759.89	2,759.89	2,760.66	2,752.07
Fixed O&M Costs	293.56	293.56	293.56	293.56	293.56	293.56
Variable O&M Costs	101.19	101.19	101.28	101.28	101.41	101.20
Emission Credit Costs	415.16	415.16	416.30	416.30	412.85	415.19
Market Purchases	130.34	130.34	120.17	120.17	120.28	129.87
Subtotal	3,692.30	3,692.30	3,691.21	3,691.21	3,688.75	3,691.90
Off-system Sales						
Fuel Costs	423.63	423.63	420.88	420.88	388.29	422.85
Variable O&M Costs	12.85	12.85	12.77	12.77	11.80	12.84
Emission Credit Costs	54.83	54.83	54.54	54.54	49.77	54.77
Market Purchases	-	-	-	-	-	-
Subtotal	491.30	491.30	488.19	488.19	449.86	490.46
Transmission System Operation Costs						
A&G Costs Associated with RTO Status	6.20	6.20	3.80	3.80	3.80	3.80
Reliability Coordinator and OASIS Services	-	-	-	2.48	2.48	2.48
Subtotal	6.20	6.20	3.80	6.28	6.28	6.28
Transmission Usage Costs						
Transmission Payments	24.60	24.60	9.45	9.45	9.45	10.23
Transmission Congestion Payments	78.56	78.56	-	-	-	-
Subtotal	103.16	103.16	9.45	9.45	9.45	10.23
Uplift Charges						
Schedule 21 Uplift Charges	3.86	-	-	-	-	-

Miscellaneous Uplift Costs	2.23	-	-	-	-	-
Subtotal	6.09	-	-	-	-	-
Legal, Regulatory & Transaction Costs	3.78	3.78	2.83	1.89	1.89	1.89
Total Costs	4,374.59	4,403.33	4,254.98	4,226.05	4,185.25	4,229.78
Revenues						
Transmission Revenues						
Transmission Revenues	(46.82)	(46.82)	(18.78)	(18.78)	(18.78)	(18.78)
Subtotal	(46.82)	(46.82)	(18.78)	(18.78)	(18.78)	(18.78)
Off-system Sales Revenue	(728.60)	(728.60)	(717.69)	(717.69)	(654.76)	(730.46)
FTRs						
FTR Revenues (as offset to congestion payments)	(74.64)	(74.64)	-	-	-	-
Share of Net Revenue from FTR Auction	(8.91)	(10.49)	-	-	-	-
Subtotal	(83.54)	(85.13)	-	-	-	-
Total Revenues	(858.96)	(860.54)	(736.47)	(736.47)	(673.54)	(749.24)
Net Recurring Cost	3,515.63	3,542.79	3,518.52	3,489.59	3,511.71	3,480.54
Non-recurring Cost (Exit Fee)	-	24.81	24.81	24.81	24.81	24.81

Table A.2
Differences of Present Value of Revenues and Costs: Selected Cases
(millions of dollars; present value to 2003, 2005-2010)
(Positive numbers are costs; Negative numbers are revenues)

Category	MISO Base Case minus PJM Case	MISO Base Case minus SPP Case	MISO Base Case minus TORC Baseline Scenario	MISO Base Case minus TORC Low-Transfer Scenario	MISO Base Case minus TORC High-Transfer Scenario
Administrative Costs					
Implementation & Administration Charges	(10.80)	34.34	64.79	64.79	64.79
Ancillary Services Market Administration	0.89	0.89	0.89	0.89	0.89
Other Administrative Costs	-	(0.03)	-	-	-
Subtotal	(10.03)	35.09	65.56	65.56	65.56
Operations Costs					
Generation Costs					
A&G Costs Associated with RTO Status	-	1.98	1.98	1.98	1.98
Native Load					
Fuel Costs	-	(7.84)	(7.84)	(8.61)	(0.02)
Fixed O&M Costs	-	-	0.00	-	-
Variable O&M Costs	-	(0.09)	(0.09)	(0.27)	(0.01)
Emission Credit Costs	-	(1.15)	(1.15)	2.31	(0.04)
Market Purchases	-	10.17	10.17	10.13	0.47
Subtotal	-	1.09	1.09	3.55	0.40
Off-system Sales					
Fuel Costs	-	2.74	2.74	35.34	0.78
Variable O&M Costs	-	0.08	0.08	1.04	0.01
Emission Credit Costs	-	0.29	0.29	5.06	0.06
Market Purchases	-	-	-	-	-
Subtotal	-	3.11	3.11	41.45	0.84
Transmission System Operation Costs					
A&G Costs Associated with RTO Status	-	2.40	2.40	2.40	2.40
Reliability Coordinator and OASIS Services	-	-	(2.48)	(2.48)	(2.48)
Subtotal	-	2.40	(0.08)	(0.08)	(0.08)
Transmission Usage Costs					
Transmission Payments	-	15.15	15.14	15.15	14.37
Transmission Congestion Payments	-	78.56	78.56	78.56	78.56
Subtotal	-	93.71	93.71	93.71	92.93
Uplift Charges					
Schedule 21 Uplift Charges	3.86	3.86	3.86	3.86	3.86
Miscellaneous Uplift Costs	2.23	2.23	2.23	2.23	2.23
Subtotal	6.09	6.09	6.09	6.09	6.09
Legal, Regulatory & Transaction Costs	-	0.94	1.89	1.89	1.89
Total Costs	(28.75)	119.61	148.53	189.34	144.80

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP	)	
OF LOUISVILLE GAS AND ELECTRIC	)	
COMPANY AND KENTUCKY UTILITIES	)	CASE NO. 2003-00266
COMPANY IN THE MIDWEST INDEPENDENT	)	
TRANSMISSION SYSTEM OPERATOR, INC.	)	

SUPPLEMENTAL TESTIMONY OF
MICHAEL S. BEER
VICE PRESIDENT, RATES AND REGULATORY
LG&E ENERGY LLC

Filed: September 29, 2004

Q. Please state your name, position and business address.

A. My name is Michael S. Beer. I am Vice President of Rates and Regulatory for LG&E Energy, LLC, the parent company of Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU" or "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A statement of my qualifications was attached to my previously filed testimony in this case.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before the Commission in this proceeding and filed both direct and rebuttal testimony. I testified most recently before this Commission in the Companies' retail rate cases, Case Nos. 2003-00433 and 2003-00434. I have also testified before this Commission concerning regulatory policies in Case No. 2001-104, *In the Matter of: Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance With E.ON AG's Planned Acquisition of Powergen plc.* I have also testified in environmental surcharge proceedings on behalf of the Companies.

Q. What is the purpose of your testimony?

A. My testimony gives an overview of the rate and regulatory issues and concerns that the Companies have with respect to continued membership in the Midwest Independent Transmission System Operator ("MISO"), particularly concerning MISO's recently filed Energy Markets Tariff ("EMT"), which creates the so-called MISO "Day 2 markets." I will also address the possibility of the Companies' joining another Regional Transmission Organization ("RTO"), such as PJM Interconnection, LLC ("PJM") or Southwest Power Pool ("SPP"). I will conclude that, from the Commission's perspective, Kentucky's public interest will be best served if the Commission orders the

Companies to seek exit from MISO and obtain reliability coordination services from a third party-provider, conditioned upon receiving approval from the Federal Energy Regulatory Commission ("FERC").

<u>MISO's EMT and the Effect of MISO Day 2 on the Companies</u>

Q. What are the Companies' overall concerns with respect to MISO's EMT and the Day 2 markets it creates?

A. The Companies are primarily concerned that MISO's EMT will impose significant costs and risks on the Companies and their customers by fundamentally altering the manner in which the Companies meet their obligation to serve retail consumers in the Commonwealth of Kentucky. Today, the Companies dispatch their lowest-cost generation to benefit their native load customers. If the Companies can purchase power less expensively than they can produce it, they buy that power for their customers' benefit. The Companies purchase a relatively small amount of energy because the Companies have some of the lowest-cost generation in the nation. The Companies also make a relatively small amount of off-system sales ("OSS") with their excess generating capacity. In this way, the Companies have ensured that their customers enjoy some of the lowest rates in the nation while optimizing the use of their generation assets by making all the economic trades they can find in the wholesale market. This approach has also resulted in the Companies historically running their generating units at high capacity factors, as Table 2 in the testimony filed today by Mr. Gallus demonstrates.

The fundamental -- and detrimental -- change that the EMT imposes is that under Day 2, the Companies' resources will be operated to optimize the economics of the MISO footprint, rather than solely for the benefit of the Companies' Kentucky customers. This loss of control over dispatch of the Companies' generation will deprive the

Companies of the operational authority they need to ensure that their Kentucky native load customers are served and, consequently, will deprive the Commission of its traditional oversight of those operations. Day 2 will also subject the Companies to significant costs and risks, some of which are difficult to quantify. Finally, Day 2 implementation will effect critical changes to the longstanding operating and regulatory principles that have guided the Companies' supply-side and demand-side operations for many decades.

Q. What are the Companies' particular concerns with respect to Day 2?

A. These are the Companies' particular concerns with respect to MISO Day 2:

(1) As more fully explained in Martyn Gallus' testimony, the Companies will incur significant new costs and risks to serve their native load. The Companies currently dispatch their generating fleet to provide their native load customers with the lowest-cost generation at the Companies' disposal, affording the Companies' customers some of the lowest rates in the nation. In Day 2, MISO will coordinate generation and transmission supply and demand to optimize the economic outcome across the entire MISO footprint, rather than solely for the benefit of the Companies' customers. This MISO-wide economic optimization will result in more risk and uncertainty and may result in higher costs for the Companies to serve their native load. Contrary to MISO's assertions, the Companies' ability to "self-schedule" their generation assets will not alleviate this problem, as is also more fully described herein. Furthermore, as Mr. Morey shows in his testimony and cost-benefit analysis, MISO's optimization across its

footprint will not work to the advantage of the Companies' customers on any reasonable set of assumptions.

In summary, in today's market, the Companies manage their own generation on an economic basis, but in Day 2 the Companies' customers will risk having generation dispatched in a fashion that is not in their economic best interests.

(2) MISO Day 2 will socialize various costs across MISO's market participants, often in ways that do not follow common principles of cost causation. For example, utilities that have relatively limited transmission links with the rest of MISO, meaning that they have relatively limited ability to import and export power due to congestion on their transmission lines, will receive an extra allotment of Day 2 Financial Transmission Rights ("FTRs") to help hedge against the transmission congestion costs that the Day 2 market effectively imposes. Not everyone can transmit or receive power across a given constrained transmission line at the same time, so whoever does use it must pay for it -- this is a "congestion cost" -- either in FTRs, which are dollar-denominated, or in cash. Because MISO issues only a limited number of FTRs it can "honor" across its footprint at any one time, allotting a greater number of FTRs to certain utilities acts as a subsidy of those utilities' congestion costs by other transmission consumers. This subsidy and other costs that MISO socializes across its market participants are inconsistent with principles of cost causation and will be detrimental to the Companies' customers.

(3) The degree of control that MISO will exercise over the Companies in Day 2 will erode the Commission's traditional jurisdiction over the Companies. For example, in Day 2 MISO will be able to instruct the Companies which interruptible retail customers to interrupt so MISO can manage regional loading; today, the Companies use their interruptible customers to manage their own system loading. FERC is MISO's sole regulator. As a result, this additional MISO control over the Companies risks shifting de facto jurisdiction over the Companies from this Commission to FERC. This shift will also deprive the Companies of the authority they require over their own resources to assure their customers of reliable, low-cost service.

(4) The likely overall impact of the Day 2 markets will be to increase the costs of the Companies' customers in order to benefit ratepayers in other states by using the Companies' low-cost generation for other states' ratepayers, not Kentucky's, and to require the Companies to purchase power at prices that are likely to be higher than the cost of the Companies' generation. This likely result is consistent with MISO's goal of optimizing the economic outcome in the wholesale energy marketplace across its entire footprint, but contradicts what the Companies believe to be the Commission's and the Governor's expressed views and policies concerning RTOs.

Q. Are you suggesting that MISO's Day 2 markets create no net benefits at all?

A. No. The Companies did not analyze whether MISO provides any benefits across its entire footprint, because the Companies' Kentucky customers are their primary concern. Although it is possible that MISO will create net benefits across its regional footprint on the whole, the Companies' analyses provided by Messrs. Gallus and Morey show that they and their customers will likely be net losers in MISO's Day 2 markets. The Day 2 market benefits the Companies can reasonably expect will not offset the overall costs and risks anticipated with the Companies' continued MISO membership. Thus, there may be benefits associated with Day 2, but it is unlikely that Kentucky will enjoy any such net benefits.

Q. What costs and risks of Day 2 are of particular concern to the Companies?

A There are two important negative cost and risk impacts that MISO's EMT will have on the Companies and their customers. First, as Mr. Gallus describes more fully in his testimony, the Companies will pay "uplift" costs, such as start-up and no-load costs,[1] that MISO "socializes," i.e., MISO makes each market participant pay a portion of the cumulative costs. However, MISO does not socialize the start-up and no-load costs of self-scheduled units; the self-scheduler must pay such costs on its own. The consequence of socializing non-self-scheduled start-up and no-load costs is that integrated utilities, such as the Companies, that presently self-schedule generation in order to meet forecasted native load obligations, will incur in Day 2 not only their own start-up and no-load costs, but also a share of other generators' socialized start-up and no-load costs across the MISO footprint.

The Companies believe that this approach is inequitable and contrary to cost causation principles, as it effectively assesses additional charges on integrated utilities that self-schedule generation and subsidizes all MISO generation that does not self-schedule. Because the Companies' self-scheduled units' start-up and no-load costs will

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[1] Start-up costs are the costs incurred in bringing a generator from stand-still to full operation. No-load costs are the costs incurred when a generator's turbines are spinning but it is not producing power.

not be socialized, revenue from these charges will effectively subsidize loads that elect to obtain all of their capacity and energy requirements from the MISO wholesale markets. The Companies believe that such an approach will almost certainly create additional costs for customers.

The Companies' other particular cost concern derives from FERC's August 6, 2004 order, in which FERC adopted additional protections for entities residing in Narrow Constrained Areas ("NCAs"). NCAs are areas with limited transmission capacity and, as a result, the market participants therein will face higher congestion costs in Day 2 than most other market participants in the MISO footprint. During a five-year "transitional period," FERC will essentially allow entities located in NCAs to obtain a special, enhanced congestion cost hedge by receiving additional FTRs. These extra FTRs effectively function to socialize the NCA entities' congestion costs across all MISO market participants. The Companies believe that the adoption of this transitional hedging mechanism moots the purpose of LMPs and violates standard cost causation principles. If LMPs are "good public policy" and "just and reasonable," it is because LMPs are supposed to identify areas where generation or transmission investments are needed and provide market participants and regulators incentives to make those investments. By extending a special congestion cost hedge to NCA utilities and socializing the NCA congestion costs, FERC and MISO essentially mute the volume of the LMP price signal by shifting the costs to utilities like the Companies that did not cause them and cannot control them.

Because of these concerns and others concerning Day 2, the Companies have petitioned FERC for rehearing of its August 6, 2004 order conditionally approving MISO's EMT. FERC has yet to rule on the Companies' petition.

The full impact of the above costs and risks are impossible to predict because they will change, quite literally, from hour to hour. This creates further significant uncertainty about the cost to serve the Companies' customers in Day 2.

Finally, it is important for the Commission to note that Kentucky's ratepayers will ultimately bear the increased risks and costs of Day 2 through increased rates.

Q. How will Day 2 affect the Companies' ability to meet its obligation to serve native load?

A. The Companies -- not MISO -- are obligated on a daily basis to provide available generation capacity sufficient to ensure that customer energy demand is met regardless of cost. This is the Companies' obligation to serve, which can be satisfied only if the Companies retain the operational authority necessary to carry out this responsibility. And to the extent that the Companies must cede operational authority to MISO in Day 2, the Commission will lose corresponding jurisdiction over the Companies' operational authority, as MISO is regulated only by FERC.

The Companies built their generating facilities to serve their native load customers, and obtained authority to build them pursuant to the Commission's Integrated Resource Planning regulation and Certificate of Convenience and Necessity process. Today, the Companies' native load has, in effect, a first "call" on the Companies' generation assets -- assets the customers paid for through retail rates. In Day 2, however, MISO will have the first "call" on the Companies' customer-financed generation resources.

MISO will have this first "call" on the Companies' generation in Day 2 because MISO will be able to: (1) schedule the commitment of the Companies' generation capacity to satisfy forecasted demand outside the Companies' service territory; (2) control the dispatch of the Companies' generation resources; (3) in emergency conditions, recall the Companies' self-scheduled generation to supply energy-deficient areas outside the Companies' control area; and (4) control and schedule the Companies' interruptible retail customer load. MISO will, therefore, have the ultimate authority over the use of the Companies' integrated supply resources, but will not assume any obligation to serve the Companies' customers. Further, to the extent that MISO will have the authority to determine where new generation is built, the Commission will lose its oversight and authority presently vested in its Integrated Resource Planning regulation and Certificate of Convenience and Necessity process. Despite this shift to MISO of the Companies' obligation to serve native load in Day 2, MISO maintains that it will not assume any of these obligations. Therefore, it is still unclear to the Companies how, in Day 2, they will fulfill their obligation to serve native load after relinquishing much of their authority to do so, while MISO will assume the authority without assuming the obligation.

In sum, Day 2 presents new risks to the Companies' native load customers because the Companies will no longer be in a position to guaranty the availability of all their generation capacity, the cost of which is in base rates, to ensure energy delivery to native load.

Q. How will Day 2 affect the Companies' net revenues from off-system sales ("OSS")?

A. As Mr. Gallus shows in his testimony, it is likely that the Companies will experience no material change in net revenues from OSS regardless of whether they are MISO members. It is important to note that increased net revenues from OSS are supposed to justify the costs of MISO's Day 2 markets, but they do not, as Mr. Morey shows. Furthermore, should the Companies actually experience lower OSS net revenues in Day 2, it will result in higher rates for the Companies' customers after the Companies' next rate cases.

But more fundamentally, the Companies' customers have financed the Companies' generation assets to serve native load, not to speculate in the wholesale markets. Kentucky's regulatory framework and the Companies' vertically integrated structures have served the Companies' customers and the Commonwealth well for many years. Day 2 threatens to undermine the Commission's ability to regulate the Companies as effectively as it has in the past, and threatens the Companies' authority to ensure their native load customers are served reliably at the lowest possible prices. The Companies believe that the prospect of realizing a small amount of additional OSS -- if any -- does not reasonably justify taking on such costs and risks.

<u>MISO's Administrative Costs and Governance Concerns</u>

Q. In their previous testimony in this case, the Companies' witnesses expressed concern that MISO's administrative costs were growing and that the Companies, due to MISO's governance structure, had no effective means to restrain them. Do the Companies still have such concerns?

A. Yes. As a chart in Mr. Morey's testimony shows, RTOs have displayed a consistent trend with respect to their administrative costs: they go up, often quite sharply, over the course of a few years. Many of these costs might be expected in the initial start-up stages, but it is worrisome to see the trend continue as RTOs "mature," leading to the suspicion that the RTO structure might effectively protect decision-makers from the negative impacts of inappropriate and inefficient decisions. Indeed, because of the nature of MISO's administrative costs -- very little "bricks and mortar," with a vast predominance of high-tech hardware and software with necessarily short life-cycles, plus a growing number of professional employees -- the Companies and the Commission can expect to see MISO's administrative costs continue to rise. Although the Companies hope that MISO's costs will plateau at some point, if PJM is a fair indicator of how more mature RTO markets behave, the Companies are concerned that MISO's administrative costs will continue along the upward trend shown in the chart in Mr. Morey's testimony.

In addition to MISO's administrative costs, on September 20, 2004, FERC approved MISO's request to recover through Schedule 10 the $8.7 million in costs Illinois Power incurred in connection with its failed attempt, with others, to create the now-defunct Alliance RTO. In other words, the Companies -- and their customers -- will now have to pay a portion of the costs Illinois Power incurred in attempting to create a failed RTO. This violates cost causation principles and raises concerns with the Companies that MISO may make similar bargains in the future that will prove costly to the Companies and their customers.

As the South Dakota Public Utilities Commission ("SDPUC") recently demonstrated in its Motion for Leave to Intervene Out of Time in the FERC MISO EMT docket, the Companies are not alone in their belief that MISO's Day 2 may not work for all MISO members.[2] The SDPUC stated that Otter Tail Power ("OTP") and Montana-Dakota Utilities ("MDU") believe that "the MISO TEMT [EMT] simply cannot be rationally applied, both operationally and economically" to the OTP and MDU systems, which are situated on the edge of the MISO footprint and rank low in annual average customer income.[3] The SDPUC then suggested that MISO hold the utilities harmless until all material issues have been resolved, rather than subject their citizens to unnecessary risks.

The Companies respectfully request that the Commission consider the same concerns voiced by the SDPUC in determining whether the Companies should seek exit from MISO.

MISO's EMT and its Effect on Jurisdictional & Policy Issues

Q. Will MISO's EMT encroach upon the Commission's traditional jurisdiction over the Companies?

A. Yes. The Federal Power Act ("FPA") §201(b) reserves to the states exclusive jurisdiction over regulated utilities' generating facilities and retail sales. MISO's EMT, however, requires MISO's load serving entities, like the Companies, to pay to use ratepayer-financed generation to serve their customers, as described above, and to purchase energy from the MISO market. In other words, the EMT encroaches on matters traditionally reserved to the Commission. It would appear that this crossover may be in violation of the FPA. Without judicial precedent for guidance, however, and unless and until the Commission orders the Companies to do otherwise, the Companies believe they will be compelled by virtue of operating under the MISO EMT to submit to FERC's jurisdiction

[2] Midwest Independent Transmission System Operator, Inc. (FERC Docket No. ER04-691-000), Motion for Leave to Intervene Out of Time by the South Dakota Public Utilities Commission (9/15/2004).
[3] Id. at 2-3.

over their generation and retail sales to native load. This jurisdictional encroachment occurs because, under the EMT, public utilities must become "Market Participants" by making their generation facilities available to the MISO "pool," even if such utilities wish to use their generation resources solely to self-serve their native load. In addition, by mandating that the Companies schedule through or purchase energy from the pool (rather than permitting the Companies fully to self-serve their native load from their own generating facilities), the EMT essentially expands FERC's jurisdiction to encompass what are today retail sales of electric energy to native load. In this regard, at least some state-jurisdictional bundled retail sales service must be "converted" under the EMT into wholesale service by virtue of the mandatory terms of the tariff.

In sum, the EMT mandates a level of MISO control over an integrated utility's supply chain, thereby changing the traditional dividing line between state and federal jurisdiction due to MISO being an exclusively FERC-regulated entity.

Q. What impact would MISO's EMT have on the Commission's jurisdiction over Integrated Resource Planning ("IRP") and resource adequacy?

A. MISO's EMT will have a significant impact on integrated resource planning and resource adequacy. All of these processes and determinations will be regionalized in the sense that the Companies will no longer be able to make critical decisions for themselves, subject to Commission oversight, but will be part of a much larger MISO operation that is subject to MISO and FERC authority. With respect to IRP, for example, MISO EMT §70.1.1 provides that the Companies' interruptible retail customers can be interrupted at the direction of MISO to manage regional loading, not exclusively by the Companies to manage their own system loading in compliance with Commission directives.

The MISO EMT will also impact the Commission's jurisdiction over resource adequacy. MISO can require the Companies to have a greater reserve margin than that currently proposed by the Companies and reviewed by the Commission. On the other hand, both MISO and the Commission might choose to lower reserve margins due to the availability of other resources through MISO's capacity markets. Regardless, the possibility remains for MISO to prescribe resource adequacy standards different from those the Commission prescribes.

Therefore, MISO's EMT will encroach upon the Commission's traditional jurisdiction over the Companies' resource adequacy requirements and service to interruptible retail customers, and will significantly change the context in which the Commission will exercise its jurisdiction over the Companies generally.

Q. Given all of the issues you have cited with MISO's EMT, would the Companies' continued participation in MISO be consistent either with this Commission's policy concerning RTOs or with the public interest?

A. No, the Companies' continued MISO participation would be neither consistent with the Commission's stated policy with respect to RTO participation, nor would it be in the public interest for Kentucky ratepayers.

Q. What is the Companies' understanding of Commission's policy concerning RTOs, and why is MISO's EMT inconsistent with it?

A. Although the Commission has encouraged the Companies' participation in MISO over the years and recently approved AEP's application to join the PJM RTO ("PJM"), the Commission has stated that its primary interest in RTOs is to support the greater reliability of the regional transmission system. As the Commission noted in its order initially rejecting AEP's request to enter PJM, "RTOs were intended to be independent bodies with functional control over utility *transmission* systems" (emphasis added). If MISO sought only to continue to supply reliability-enhancing services, then MISO's objectives and the Commission's RTO policy would align, although the Companies would still object to MISO's high cost for those services, as the Companies' witnesses noted in their previous testimony.

The purpose of MISO's EMT, however, is to go beyond merely providing reliability services. MISO now seeks to create energy markets that will not, on the whole, benefit the Companies or their customers, but will impose market rules compromising the Commission's jurisdiction over the Companies' generation assets. In apparent contravention of Commission policy, MISO's EMT will jeopardize the Companies' ability to fulfill their obligation to serve their customers' load.

I would also like to note that MISO's Day 2 markets are inconsistent with not only the Commission's policies but also the Governor's. In a February 3, 2004 letter to President Bush, Governor Fletcher and eight other southern governors stated that they remained "adamantly opposed" to imposing FERC's Standard Market Design in the south, which is essentially what MISO's EMT puts in place in the Companies' service territory. The governors noted that rate-regulated, vertically integrated utilities have provided and will continue to provide the south with "low rates, appropriate infrastructure investment, and reliable electric delivery service." Although it is true that the Companies voluntarily joined MISO, they simply did not anticipate at that time how costly and risky MISO's markets ultimately would become (as fully described in LG&E's witnesses' previous testimony). The Companies agree with Governor Fletcher that rate-regulated, vertically integrated utilities, such as the Companies, are the best model for Kentucky for the reasonably foreseeable future.

Q. What effect will the EMT have on the Power Supply System Agreement ("PSSA") between LG&E and KU?

A. The precise effect that the EMT will have on the PSSA is uncertain. Since October 1997, the Companies have operated under the PSSA, the purpose of which is "to provide the contractual basis for the coordinated planning, construction, operation and maintenance of the System to achieve optimal economies, consistent with reliable electric service and environmental requirements." It has indeed provided the basis for the Companies' joint operation, including the Companies' joint dispatch. As I have discussed above, under the EMT MISO will assert authority to exercise control over several, if not most, of the factors the PSSA currently addresses between the Companies.

The Companies have two primary concerns with respect to the PSSA under Day 2. First, because the EMT and PSSA are both FERC-approved agreements, it is unclear which of the two agreements' apparently conflicting provisions will ultimately be found to be controlling. Second, as I have discussed at length above, the Companies are greatly concerned that the Companies' customers will be harmed when the Companies' PSSA-created joint dispatch ceases to function to optimize the economic outcome for Kentucky's customers and will instead be directed by MISO to help optimize the economic outcome for the region.

<u>Possible Participation in Other RTOs and the Companies' Desired Result In This Case</u>

Q. What result do the Companies believe is most consistent with Kentucky's public interest?

A. After a careful survey of plausible alternative RTOs and further studying MISO's EMT, the Companies have concluded that the best result for the Companies and their customers would be for the Commission to allow the Companies to seek exit from MISO and acquire reliability coordination services from a third-party provider, conditioned, of course, on FERC approval. As Mr. Johnson testifies, the Companies could, outside of MISO, continue to operate in a manner that avoids significant rate impact for the Companies' customers, prevents impairment of this Commission's jurisdiction over their generation assets, and ensures the Companies' continued ability to fulfill their obligations both as state-franchised natural monopolies and as FERC-jurisdictional entities. Although the Companies cannot be certain that FERC will grant such an approval, given the evidence presented, the Companies are left with no choice but to seek the changes outlined herein.

Q. What is the appropriate standard governing any transfer of functional control of the Companies' transmission assets from MISO?

A. As MISO and the Companies have argued, and as the Commission stated in its orders concerning AEP's application to join PJM, KRS 278.218 governs transfers of functional control of utility assets. Just as it did not apply to the Companies' initial transfer of functional control to MISO, KRS 278.020(5) (formerly KRS 278.020(4)) would not apply to a transfer of functional control of the Companies' transmission assets away from MISO so that the Companies could acquire reliability coordination services from a third-party provider.

Q. Would allowing the Companies to seek exit from MISO and obtain reliability coordination services from a third party comport with the KRS 278.218 standard governing a transfer of control of a utility's assets?

A. Yes. For a transfer to meet the requirements of KRS 278.218(2), it must be "for a proper purpose and . . . consistent with the public interest." The Commission has further stated: "This standard establishes a two-step process: first, there must be a showing of no adverse effect on service or rates; and, second, there must be a determination that there will be some benefits." With respect to the first step of the Commission's two-part analysis, the record already shows, and Mr. Johnson's testimony filed today states, that the Companies can achieve excellent reliability by using a third-party provider such as TVA as its reliability coordinator, and at significantly lower cost than MISO charges for the same service. Moreover, the Companies' long history of superb reliability is a matter of public record and institutional knowledge by many on the Commission staff.

With respect to the second prong of the Commission's two-part analysis, the Companies' independent cost-benefit analysis shows that exiting MISO and acquiring reliability coordination services from a third-party provider will produce net economic benefits as compared to joining SPP or PJM, or continuing the Companies' MISO membership. Therefore, allowing the Companies to exit MISO and acquire reliability coordination services from a third-party provider would satisfy the second prong of the KRS 278.218 test.

If the Commission finds the Companies' evidence concerning reliability and their analysis of quantifiable and unquantifiable costs and risks to be persuasive, ordering the

Companies to seek exit from MISO to acquire reliability coordination services from a third-party provider would indeed comport with KRS 278.218.

Q. If the Commission ordered the Companies to exit MISO, would the Companies seek rate recovery of the MISO exit fee?

A. In the Companies' recent rate cases (Case Nos. 2003-00433 and 2003-00434), the Attorney General's witness, Mr. Robert J. Henkes, appeared to endorse the Companies' position that the Commission allow the Companies to establish a regulatory asset in the amount of the MISO exit fee. However, Mr. Henkes proposed that, rather than having a separate rate-making proceeding to include the MISO exit fee costs and terminate rate recovery of the Companies' Schedule 10 costs in base rates, the Companies should instead continue to collect Schedule 10 costs through the new base rates after exiting MISO. Mr. Henkes further suggested that the Commission should order the Companies to establish a regulatory liability account for the amounts the Companies continue to recover in base rates for the Schedule 10 costs they no longer incur. The balance in the regulatory liability account would be used to offset the regulatory asset the Companies establish for the amount of the MISO exit fee in their next base rate cases. If the regulatory liability account exceeded the amount of the regulatory asset, the excess would be returned to customers in an appropriate manner.

In my rebuttal testimony, I stated that the Companies endorse Mr. Henkes' proposal, provided that four conditions are met: (1) FERC issues an order authorizing the Companies' exit from MISO; (2) FERC lawfully establishes the appropriate amount of the MISO exit fee; (3) MISO Schedule 10 charges concurrently cease at the time of the Companies exit from MISO and incurrence of the exit fee; and (4) revenues associated with the MISO Schedule 10 charges (i.e. $3,168,131 for LG&E and $3,485,404 for KU) be recorded in a regulatory liability account to offset the FERC-approved MISO exit fee until the Companies' next base rate proceedings. At the hearing, Mr. Henkes testified that he agreed with the Companies' rebuttal position. To my knowledge, there is no testimony in the rate case record opposing this proposal. Moreover, the Attorney General's earlier brief in this proceeding supports this plan.[4]

The Companies continue to believe that this proposal is an appropriate method for recovering the MISO exit fee and respectfully request that the Commission allow the Companies to recover the exit fee in this way should the Commission order the Companies to exit MISO.

Q. In their recent mergers, the Companies made commitments to FERC concerning MISO and RTO participation generally. What were those commitments, and do they pose a potential obstacle to the Companies' successful withdrawal from MISO?

A. In my previous testimony in this case, I addressed at length issues concerning the Companies' merger commitments, how they might pose an obstacle to obtaining FERC approval for the Companies' exit from MISO, and what sorts of conditions FERC might impose on an approval of the Companies' exit from MISO. In short, the Companies committed to remain MISO members through the end of 2002, and members of a FERC-approved RTO thereafter. However, the Companies made that commitment, and earlier ones like it, only as a means of mitigating their supposed market power. FERC acknowledged as much in its order approving the E.ON acquisition of Powergen and the

[4] <u>In the Matter of: Investigation Into The Membership of Louisville Gas and Electric Co. and Kentucky Utilities Co. In the Midwest Independent Transmission System Operator, Inc.</u>, Case No. 2003-00266, Post-Hearing Brief of the Attorney General at 4-5 (4/26/2004).

Companies, stating in the sentence immediately following the Companies' RTO commitment, "Therefore, they [LG&E and KU] lack the ability to exploit their transmission assets to harm competition in wholesale electricity markets." The context in which the Companies committed to remain in an RTO allows them now in good faith to recommend that the Commission order the Companies to seek to exit MISO and acquire reliability coordination services from a third-party provider, subject to FERC approval.

Thus, although the merger commitments remain an issue with respect to MISO withdrawal and it is not clear whether FERC will ultimately approve such a withdrawal, the Companies believe there are reasonable grounds upon which to seek FERC approval based on changing circumstances.

Q. Given that the KPSC recently approved AEP's entry into PJM, wouldn't a similar stipulation between MISO and the Companies also align with the Commission's expressed views on RTOs?

A. No, such a stipulation would not align with the Commission's expressed views on RTOs, nor would it align with the public interest, simply because this case is unlike the AEP-PJM case in several important ways. First, PJM's power pool is well-established and has functioned for a number of years as a single control area. MISO's Day 2 markets, on the other hand, are being built from the ground up, and are, as such, untested and already enormously expensive. Indeed, even FERC has stated that "LMP can be costly and difficult to implement, particularly by entities that have not previously operated as tight power pools." In the wake of the blackouts of August 14, 2003, this Commission should be wary of untested and costly ventures.

Second, AEP is seemingly a good fit for PJM, as AEP is a regional company that already plans and manages its generation and transmission regionally through exclusively FERC-regulated AEP generation pooling arrangements among the AEP subsidiaries. The Companies, on the other hand, are not regional entities with FERC-regulated pooling arrangements. Throughout their histories, the Companies have planned their resources to serve their native load in Kentucky. Today, the Companies provide their customers with award-winning service at some of the lowest rates in the nation. The Companies' customers deserve to have that low-cost service continue, rather than having their rates increase for the benefit of customers in other states.

Third, in the AEP-PJM case, no party disputed the assertion that AEP's membership in PJM would redound to the benefit of AEP's customers in Kentucky. In this case, however, there is cost-benefit evidence that would support an exit from MISO. MISO has claimed that it has conveyed and will convey upon the Companies net benefits in the hundreds of millions of dollars. The Companies, on the other hand, have more conservatively shown that exiting MISO is the superior course for the Companies and their customers between 2005-2010, conveying net benefits from $4 million to $35 million[5] as compared to continued MISO membership.

Q. The Companies also expressed concern earlier in this proceeding that MISO membership jeopardized their ability to comply with the requirements of Kentucky's curtailment statute, KRS 278.214. Given that the Commission accepted the stipulation in the AEP-PJM case concerning the same issue, would the Companies continue to see KRS 278.214 as an impediment to their continued MISO membership if MISO agreed to a similar stipulation?

[5] See Mr. Morey's testimony and cost-benefit analysis.

A. Were MISO to agree to a stipulation similar to that in the AEP-PJM case concerning curtailment procedures, it would go a great way toward alleviating my concern with respect to KRS 278.214. However, I would still harbor some degree of concern until the courts have finally passed on this issue. I also acknowledge that this concern applies to any membership the Companies might have in PJM or any other regional transmission organization that erodes both the Companies' control area authority and ability to assign LG&E/KU-owned capacity to LG&E/KU native load.

Conclusion and Recommendation

Q. What is the ultimate question the Commission should ask itself in considering Day 2 and MISO overall?

A. The true issue for decision is, quite simply, whether Kentucky residents and businesses should be asked to have a higher exposure to risk and ultimately, pay more for electricity, and forfeit the benefit of Commission oversight over these matters, so that residents and businesses in other states can pay less. The Companies submit that the Commission's answer should be no. Because MISO's Day 2 markets will compromise the Commission's jurisdiction and result in net costs and risks for the Companies and their Kentucky customers, the Companies' continued MISO participation is not in the public interest.

Q. What do you recommend the Commission order in this case?

A. The Commission should determine that the Companies' continued membership in the MISO is no longer in Kentucky's public interest. It should further determine that the proposed transfer of the functional control over the Companies' transmission assets from MISO to the Companies on the condition that they acquire reliability services from a third-party reliability coordinator, pending FERC approval, is for a proper purpose and consistent with Kentucky's public interest.

Q. Does this conclude your testimony?

A. Yes, it does.