LG&E ENERGY

**LG&E Energy Corp.**
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September 22, 2003



Thomas M. Dorman
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 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 Mr. Dorman:

Pursuant to the schedule established by the Kentucky Public Service Commission in its order dated July 31, 2003, in the above-referenced docket, enclosed please find an original and ten (10) copies of the direct testimony (and associated exhibits, as applicable) of (i) Mr. Paul W. Thompson, (ii) Mr. Michael S. Beer, and (iii) Mr. Mathew J. Morey, submitted on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company.

Please confirm your receipt of this filing by placing the stamp of your office with the date of September 22, 2003 on the first page of the extra copy enclosed, and return the extra copy to me in the enclosed self-addressed, stamped envelope.

Should you have any questions regarding the enclosed, please do not hesitate to contact me directly at 502/627-2557.

Very truly yours,

Linda S. Portasik

Linda S. Portasik
Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

cc (w/enclosures): All Parties on Service List

Testimony

RECEIVED

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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 |

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

Filed: September 22, 2003

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

A. My name is Paul W. Thompson. I am the Senior Vice President, Energy Services for LG&E Energy Corp. My business address is 220 West Main Street, Louisville, Kentucky 40202.

**Q. Please describe your work experience and education.**

A. Before joining LG&E Energy Corp. in 1991, I acquired eleven years of experience in the oil and gas and energy-related industries in positions of financial management, general management and sales. I received a Bachelor of Science degree in Mechanical Engineering from the Massachusetts Institute of Technology in 1979 and a Master of Business Administration from the University of Chicago in Financing and Accounting in 1981. A complete statement of my work experience and education is contained in the Appendix hereto.

**Q. Have you previously testified before this Commission?**

A. Yes. I testified in the merger proceedings of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively referred to at times as "Companies") before the Kentucky Public Service Commission ("KPSC") in Case No. 97-300, *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger under KRS 278.020.*

Q Please provide an overview of LG&E's and KU's response to the order initiating this proceeding on July 17, 2003 ("July 17 Order").

A. My testimony describes the expectations of LG&E and KU at the time they joined the Midwest Independent Transmission System Operator, Inc. ("MISO"), and explains the changes that have occurred since that time. I also present LG&E's and KU's position regarding their future participation in MISO. In addition to my testimony, Mr. Beer discusses the regulatory environment giving rise to and currently surrounding LG&E's and KU's membership in MISO; and, based on the results of the independent cost-benefit analysis performed by Christensen Associates in this proceeding, presents the federal regulatory obstacles and potential risks to the Companies and their customers associated with pursuing an exit from MISO, even at the direction of the KPSC. Mr. Beer also addresses two other discrete issues raised by the July 17 Order: (i) the applicability of KRS Section 278.020(4) to the transfer of operational control over the Companies' transmission assets to MISO; and (ii) the appropriateness of, and jurisdictional basis for, shifting decision-making regarding resource adequacy and demand response to regional organizations such as MISO.

The remaining issues identified in the July 17 Order (the costs and benefits of the Companies' membership in MISO and the feasibility of joining a southern Regional Transmission Organization) are addressed by Mr. Morey, who presents the results of an independent cost-benefit analysis performed by Christensen Associates of LG&E's and KU's membership in MISO.

**Q. In his testimony, Mr. Beer describes the regulatory environment leading up to the formation of MISO. Against this backdrop, what steps were taken to initiate the process of forming MISO?**

A. Beginning in late 1995 and early 1996, consistent with the regulatory initiatives then being undertaken by the Federal Energy Regulatory Commission ("FERC") as described in Mr. Beer's testimony, representatives of several transmission owners met to discuss the possibility of forming an Independent System Operator ("ISO") in the Midwest region. By February 12, 1996, six transmission owners, including American Electric Power Company and Cinergy, Inc., had agreed to initiate MISO's creation, prompting LG&E's and KU's involvement shortly thereafter. LG&E's and KU's involvement was driven largely by the desire to accommodate FERC's evolving policies regarding ISOs as announced in Order No. 888, as well as the desire to manage more efficiently regional transmission service under FERC Order No. 888. Although Order No. 888 encouraged long-distance energy transactions, it failed to provide an effective mechanism for managing these transactions. Mr. Beer discusses FERC Order No. 888 more fully in his testimony.

**Q. Who was involved in the development process?**

A. Participants in the development of MISO included both large and small investor-owned utilities, municipal utilities and power agencies, and rural electric generation and transmission cooperatives. During the course of almost two years, participants in the MISO development process met regularly, and, beginning in April of 1997, meetings were open to representatives of all stakeholder groups, including environmental advocates, independent power producers and power marketers, industrial customers, state utility regulatory commissions, state consumer advocate agencies, and transmission-dependent utilities. The KPSC staff was often in attendance at these meetings.

**Q: In negotiating the terms of MISO membership, was it the Companies' objective to avoid all MISO costs?**

A: No. The Companies have never sought to avoid paying their fair share of costs. What *was* critically important to LG&E and KU, however, was ensuring that MISO's costs were appropriately allocated among the membership and their customers so as to avoid cost subsidization by, and cost-shifting to, the Companies' customers. To this end, the Companies negotiated a compromise regarding the manner in which costs associated with MISO's administrative services (so-called Schedule 10 charges) should be allocated among the membership, and, in turn, the members' customers. This cost allocation compromise was an essential consideration in persuading LG&E and KU to join the MISO and accept the MISO agreement.

**Q: Please describe this cost allocation compromise.**

A: Specifically, the proposal ultimately filed with the FERC assigned cost responsibility as follows:

(i) Bundled load customers who were not served under MISO's open-access transmission tariff ("MISO Tariff") during the "transition period" (through December 2008) -- *i.e.*, customers served from generation internal to the transmission owner's system -- would not be subject to MISO's tariff charges, including Schedule 10 charges, during this period.

(ii) However, when a transmission owner purchased off-system power to serve its bundled load -- and was thereby required to use MISO's transmission service under the MISO Tariff to effectuate delivery -- the transmission owner would pay (and recover as appropriate) MISO tariff charges, including Schedule 10 charges.

In short, the agreed-upon cost allocation would assign MISO's costs only to those customers taking service under the MISO Tariff. To ensure that the latter group of customers was not unduly burdened as a result of this transitional rate treatment, however, Schedule 10 charges were capped during the transition period (at a level well below that of other ISOs), and to the extent the capped charge was insufficient to recover MISO's costs during the transition period, unrecovered costs would be deferred for recovery from all loads after the transition period, over a five-year amortization period.

**Q: How did the compromise regarding the allocation of Schedule 10 cost responsibility affect LG&E's and KU's customers?**

The Schedule 10 compromise clearly benefited LG&E's and KU's customers. First, by so limiting the cost responsibility of the Companies' customers during the transition period, these customers, who were expected to derive only limited benefit from MISO during the transition period, would be relieved from having to shoulder a disproportionate share of MISO's expenses. Second, although LG&E's and KU's customers would, in fact, be subject to MISO's administrative costs commencing January 2009, their Schedule 10 cost exposure (including that associated with unrecovered costs deferred through the transition period, per the compromise) was not expected to be as significant on a MWH basis, *vis-a-vis* pre-2009 exposure levels.

**Q: Why was the customers' Schedule 10 cost burden expected to moderate after the transition period?**

A: This expectation was based on the belief that power flows on the transmission grid would necessarily increase in the wake of deregulation initiatives across the region, creating an expanded customer base over which to spread these costs. Moreover, some participants anticipated that, by January 2009, at least some customers would be purchasing unbundled transmission service directly from MISO in a deregulated retail environment, thereby warranting imposition of the full Schedule 10 charge on these customers after the transition period.

**Q. When did the MISO seek approval from FERC?**

A. Following the lengthy collaborative process and upon reaching the compromise agreement, on January 15, 1998, a group of nine participating transmission owners, including LG&E and KU, filed for FERC approval of the MISO open-access transmission tariff, along with a lengthy agreement governing, among other things, the respective rights and obligations of the transmission owners and MISO ("MISO Agreement"). By the time supporting testimony was filed in February 1998, the number of participation transmission owners had increased to twelve.

**Q. Did the KPSC participate in the MISO proceeding at FERC?**

A. Yes. The KPSC intervened in the proceeding in March 1998, noting therein its appreciation of MISO's "extraordinary efforts" to involve stakeholders, including regulatory commissions and customer groups, and expressly commending the utilities who participated in its formation. While the KPSC asked FERC to consider the adoption of an alternative transmission pricing proposal, it noted that its alternative proposal did "not seriously deviate from what the MISO has proposed."

**Q. Did FERC approve the establishment of the MISO?**

A. Yes. On September 16, 1998, FERC conditionally approved the establishment of MISO. In such order, the FERC also approved the essential compromises underlying MISO's creation, including the provision that bundled retail load would not be served under the MISO tariff -- and thus not subject fully to MISO's administrative costs -- during the entire transition period. However, as expected, the FERC did set several rate issues for hearing before an administrative law judge ("Presiding Judge"), including the reasonableness of the Schedule 10 charge.

**Q. What resulted from the hearing process?**

A. During the course of that proceeding, the MISO transmission owners testified that the compromise reached among MISO stakeholders regarding the allocation of Schedule 10 charges during the transition period was essential to securing an agreement among the diverse stakeholders in MISO. However, in a decision issued November 26, 1999, the Presiding Judge disregarded this testimony, instead finding the Schedule 10 charge deficient for, among other things, "tak[ing] into account only load under the [MISO tariff] and [not] existing bundled retail load and grandfathered wholesale load not served under" such tariff. According to the Presiding Judge, recognizing bundled load in this manner was warranted given that "all users of the grid" benefit equally from MISO's operation (an assumption disputed by LG&E and KU). In so ruling, the Presiding Judge effectively required the imposition of Schedule 10 costs on bundled load customers by requiring all load serving entities, including LG&E and KU, to pay Schedule 10 charges on behalf of these customers.

**Q. Did LG&E and KU object to the findings of the Presiding Judge?**

A. Absolutely. The MISO transmission owners, including LG&E and KU, filed exceptions to the Presiding Judge's decision. Despite their protests, however, the FERC, on October 11, 2001, issued Opinion No. 453, wherein it affirmed the Presiding Judge's conclusion that Schedule 10 charges must be paid on behalf of all existing bundled retail load (as well as any grandfathered wholesale load). In taking this position, the FERC relied primarily on the Presiding Judge's unsupported assumption that "all users of the grid" will benefit equally from MISO's operation. Concurrent with, and to support, this finding, the FERC unilaterally decreed that all loads, bundled and unbundled, must be placed "under" (served under) the MISO tariff.

**Q. Was rehearing of Opinion No. 453 requested?**

A. Yes. Setting in motion a lengthy legal battle, the MISO transmission owners requested rehearing of FERC Opinion No. 453. In addition, LG&E and KU separately requested that the FERC grant rehearing of its order, emphasizing the particular concerns of low-cost utilities serving areas in Kentucky. Despite these requests, on February 13, 2002, FERC (in Opinion No. 453-A) denied rehearing of the issue related to the Schedule 10 charges.

**Q. Did the parties appeal the FERC decisions?**

A. Yes. Several parties, including LG&E and KU, filed timely petitions for review with the United States Court of Appeals for the District of Columbia ("D.C. Circuit") on April 12, 2002. However, after briefs were filed but before oral argument was conducted in this judicial proceeding, the FERC took the unusual step of seeking a voluntary remand from the court to allow further consideration of the issues presented for review. On December 6, 2002, the D.C. Circuit remanded the entire record back to FERC to allow such reconsideration. Although the Companies were encouraged by the FERC's apparent decision to rethink its findings in Order Nos. 453 and 453-A, their optimism was short-lived, as the FERC, on February 24, 2003, once *again* affirmed its earlier decisions. Although the parties *again* requested rehearing of this decision on March 26, 2003, the FERC *again* denied rehearing on July 2, 2003, even while noting that "LGE/KU relied on the proposed deferral of bundled retail loads' responsibility for the [Schedule 10 charges] when making their decision to join MISO." LG&E and KU *again* petitioned the

D.C. Circuit for review of the FERC decisions in an effort to eliminate this cost burden for their customers through the appellate process. That case is currently pending.

**Q: Has the KPSC been actively involved in these MISO matters?**

A. Yes. The KPSC has been involved in the development of the MISO since at least 1997 and has actively participated in the legal proceedings before FERC. Although it has not agreed entirely with all of its terms, the KPSC has encouraged LG&E's and KU's continued participation in MISO. In fact, the KPSC included in its orders approving the Companies' acquisition by Powergen plc and E.ON AG, respectively, a "commitment" that the Companies' continue their MISO membership. Mr. Beer discusses these commitments more fully in his testimony.

**Q: In addition to the FERC's unilateral decision to impose Schedule 10 costs on bundled load, have LG&E and KU experienced other changes since joining MISO that have affected the "bargain" the Companies struck with MISO in 1998?**

A: Yes. Last fall, consistent with the FERC's standard market design ("SMD") rulemaking initiative (discussed in Mr. Beer's testimony), MISO took the first major step towards fundamentally redefining its function to include energy market development and operation. Specifically, on September 24, 2002, MISO filed two new rate schedules (Schedules 16 and 17) with the FERC to allow the recovery of costs associated with the establishment and implementation of both day-ahead and real-time energy markets within the MISO footprint ("MISO Day 2 Market"). In this filing, MISO recognized that the new role for which it was seeking cost recovery through Schedules 16 and 17 was not envisioned by the MISO membership upon MISO's inception in 1998:

> As originally organized, [MISO's] functions were limited to providing non-discriminatory open access transmission service over the

> transmission assets entrusted to its operational control and receiving and distributing funds for use of those assets as agent for the [MISO] Transmission Owners. [footnote omitted.] The authorities and responsibilities vested in [MISO] created a transmission organization compliant with the requirements of Order No. 888. [footnote omitted.] It was not, however, contemplated that [MISO] would establish or operate an energy market. Instead, to the extent that transmission service required energy-related ancillary services, [MISO] would either acquire such services on behalf of Transmission Customers or facilitate the direct acquisition of such services by the Transmission Customer from the energy provider.

*MISO Proposed Revisions to Open Access Transmission Tariff*, FERC Docket No. ER02-2925-000, September 24, 2002, Transmittal Letter at 2. After the FERC provided assurances that MISO would be permitted to recover "prudently incurred" costs under Schedules 16 and 17 (on November 22, 2002), and affirmed the "general direction" of MISO's proposed energy market rules (on February 24, 2003), MISO moved forward with the development of the MISO Day 2 Market. To that end, MISO filed with the FERC, on July 25, 2003, an Open Access Transmission and Energy Markets Tariff ("Energy Markets Tariff"), to replace the MISO Tariff, through which MISO proposes to assume the role of monitor and operator of the energy market within the MISO footprint. Although MISO represented in its filing that MISO's stakeholders supported the filing, this representation was not accurate. To the contrary, as MISO's transmission owners (including LG&E and KU) made clear in their protest to such filing (submitted to FERC on September 15, 2003), transmission owner stakeholders voiced strong concerns regarding both the scope and cost of MISO's market implementation efforts well prior and up to the July 25, 2003 filing.

In fact, with regard to LG&E and KU specifically, these concerns were heightened after issuance, on April 28, 2003, of the FERC's "White Paper" on market restructuring. This paper indicated that the FERC's final SMD rule would not require certain terms and conditions that MISO had already included in its proposed Energy Markets Tariff, and that were of particular concern to the Companies (*i.e.*, the paper suggested that the final rule, unlike MISO's proposed tariff, would afford load serving entities the option of retaining existing "physical" transmission service for native load, in lieu of obtaining FTRs). LG&E and KU were understandably concerned that MISO's regulatory "over-compliance" would bind LG&E and KU to these problematic terms and conditions (and related costs) despite the White Paper concessions -- particularly in light of FERC's announcement only weeks earlier that it did "not intend, in the final SMD rule, to revisit prior approvals because of possible inconsistencies with the . . . final SMD rule." Given these and related concerns, the Companies objected to the entirety of MISO's proposed tariff. *See* Exhibit PWT-1, Letters to MISO dated May 23, 2003 and July 11, 2003.

In addition, at LG&E's and KU's initiation, MISO's transmission owners urged the MISO Advisory Committee to recommend to the MISO Board a delay in MISO's Energy Markets Tariff filing sufficient to "allow the stakeholders time to review the minimum requirements that FERC is going to impose on RTOs and evaluate the benefits of exceeding FERC's minimum requirements." Unfortunately, this language failed to garner sufficient support from other stakeholder groups, and ultimately was not presented to the Board.

**Q: How will MISO's implementation of a regional energy market affect the Companies and their customers specifically?**

A: This wholly new function not only threatens to increase the Companies' operational and business risk (*e.g.*, associated with congestion management), but also brings with it significant additional capital and operating costs, none of which, as MISO itself acknowledges, were envisioned by the charter MISO membership in 1998.

As alluded to above, the Companies have repeatedly expressed their concerns regarding the business and operational risk attendant to MISO's implementation and administration of the MISO Day 2 Market, both formally at FERC and informally through written correspondence and face-to-face meetings with MISO. *See* Exh. PWT-1. So, too, LG&E and KU have strongly objected both to the level of projected expenditures associated with MISO's new role and MISO's failure to properly align cost responsibility with cost causation. *See* Exh. PWT-2.

**Q: Have the Companies ever before sought to exit MISO?**

A: Yes. LG&E and KU did, in fact, file a notice of withdrawal with FERC on January 4, 2001. However, that notice was premised not the increasing costs and risks attendant to membership (which had not yet fully surfaced), but rather on federal regulatory compliance issues raised by the proposed withdrawal of other members; specifically, the Companies' concerns centered on MISO's ability, in light of such withdrawals, to comply with the "scope and configuration" requirements of FERC Order No. 2000 (discussed in Mr. Beer's testimony). LG&E's and KU's concerns were ultimately addressed (and the notice was not expressly acted on by FERC) in the context of a settlement reached with the withdrawing members.

**Q. Why have LG&E and KU elected to continue their membership in MISO despite the changed circumstances discussed above?**

A. Despite the new membership terms imposed on them by MISO, as described above, LG&E and KU, until in the spring of this year, did not undertake a detailed assessment of alternatives to ongoing MISO participation. First, given (i) the exit fee imposed on withdrawing members and their customers (which the Companies' consultant estimates at approximately $23 million), (ii) the likelihood of bearing similar costs as members of another RTO, and (iii) the exhaustive efforts taken by the Companies (as well as the KPSC) over the last several years to work within the RTO construct, LG&E and KU believed it was in their customers' interest to pursue relief, at least initially, through the adjudicative process and informal discussions with MISO leadership. Second, and importantly, there was (and remains) a significant concern about LG&E's and KU's ability, as public utilities subject to FERC's jurisdiction, to withdraw from MISO in the near-term under reasonable terms (*e.g.*, without having to join another RTO, which, as noted, could well result in similar cost exposure). Mr. Beer discusses these federal regulatory issues in his testimony.

**Q. You mentioned that the Companies did not closely examine alternatives to MISO membership "until the spring of this year." Did LG&E and KU begin to consider changing their course of action with regard to the MISO prior to issuance of the KPSC's order initiating this proceeding?**

A: Yes. In fact, with the assistance of external counsel experienced in federal regulatory matters, the Companies began to assess alternatives to continued MISO membership in May of this year, prompted both by the significant unforeseen increases in the cost of MISO membership (*e.g.*, Schedules 16 and 17) as well as the FERC's latest policy pronouncement, as reflected in its "White Paper" on market restructuring, referenced above. In the latter regard, although the FERC in its White Paper still appeared committed to the RTO/ISO construct as initially proposed in its SMD initiative -- proposing to "require" RTO or ISO participation -- it did indicate a willingness to allow different RTO configurations (by imposing more flexible scope and configuration criteria on Independent System Operators), and likewise indicated greater tolerance for market implementation more "tailored to each region." This more flexible regulatory approach, which in large part (*i.e.*, regarding energy market development) MISO remains unwilling to embrace, prompted the Companies to initiate a detailed assessment of MISO alternatives.

Q. **Have LG&E and KU now determined what course of action best serves their interests and their customers?**

Yes. Although LG&E and KU clearly were prudent in their decision to join MISO in 1998, the Companies now believe that, if the KPSC is willing to support fully their efforts, as discussed below, the Companies should pursue an exit from MISO, with the aim of operating their transmission system on a stand-alone basis. As Mr. Morey discusses in his testimony, Christensen Associates has completed a detailed, independent cost-benefit analysis of various RTO options, including LG&E's and KU's continued participation in MISO, as well as stand-alone transmission operation. This analysis concludes that, from strictly an economic perspective (without taking into account any legal or regulatory constraints), LG&E, KU and their customers will derive the greatest net benefits over the next several years by operating the LG&E and KU transmission system on a stand-alone basis (outside any RTO). A stand-alone operation would allow LG&E and KU to reduce and control current operational costs and risks, while at the same time maintaining historic reliability levels and largely preserving the regional trading opportunities attendant to membership in the MISO.

In addition, a stand-alone operation would afford the KPSC the opportunity for greater ongoing regulatory oversight and direct regulation of costs. Currently, there are no effective checks on the expenditures of MISO management: because MISO is a non-profit organization with no equity at risk, there is currently no practical means to minimize MISO's expenditures consistent with good business practice.

**Q: You mentioned that the KPSC would need to fully support the Companies' efforts to withdraw from MISO. Please explain.**

A. The Companies believe that the KPSC's willingness to recognize both the efforts undertaken by the Companies to date, and the hurdles they face going forward, is essential to the success of any exit effort. First, the Companies must be allowed to recover from customers the exit fee imposed on withdrawing members, as set forth in the MISO Agreement, as well as all costs incurred in connection with LG&E's and KU's ongoing membership obligations prior to the exit. The Companies' actions to date, both in joining MISO and in aggressively working to minimize costs, have been reasonable and responsible, fully justifying the Companies' recovery of MISO costs. Second, the Companies must be allowed a reasonable opportunity to obtain the requisite pre-approvals from FERC to permit LG&E and KU to withdraw from MISO under conditions acceptable to the Companies. As discussed above and in Mr. Beer's testimony, LG&E and KU's ability to obtain requisite FERC authorization to withdraw from MISO under terms reasonable to the Companies and their customers remains uncertain, particularly in light of the FERC's recent efforts to "require" RTO participation. Sound regulation should not place the Companies in the untenable position of having to comply with conflicting federal and state regulatory directives: the KPSC should assist the Companies in extracting themselves from this federal/state conflict by awaiting a FERC ruling, and, in the interim, affording the Companies reasonable ratemaking treatment of their MISO costs, as discussed above.

**Q. What if LG&E and KU are not permitted to withdraw from MISO under reasonable terms?**

A: If LG&E and KU are not permitted to exit MISO under reasonable terms, *e.g.*, if the FERC conditions the Companies' exit on their willingness to join another RTO, the analysis necessarily changes to whether the Companies are members of the RTO which is the least-cost among the options available. Absent other alternatives that would make economic sense for the Companies and their customers, the Companies propose to remain in MISO. As Mr. Morey's analysis confirms, as among the RTO options available to the Companies, MISO is the least-cost option.

**Q. Does this conclude your testimony?**

A. Yes.

## 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, Energy Services, for LG&E Energy Corp., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

PAUL W. THOMPSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of September 2003.

(SEAL)
Notary Public

My Commission Expires:

Notary Public, State at Large, KY
My commission expires June 3, 2006

## APPENDIX

# Paul W. Thompson

Senior Vice President, Energy Services
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202
(502) 627-3861

### Civic Activities

Friends of the Waterfront Board
Library Foundation Board
Chair, Annual Appeal 2002
Co-Chair Annual Children's Reading Appeal 1999, 2000, & 2001
March of Dimes 1997 & 1998 - Honorary Chair
Habitat for Humanity - Representing LG&E as co-sponsor

### Education

University of Chicago, MBA in Finance and Accounting -- 1981
Massachusetts Institute of Technology (MIT), BS in Mechanical Engineering -- 1979
Leadership Louisville -- 1997-98

### Previous Positions

LG&E Energy Marketing, Louisville, KY
1998 - 1999 – Group Vice President
Louisville Gas and Electric Company, Louisville, KY
1996 - 1999 – Vice President, Retail Electric Business
LG&E Energy Corp., Louisville, KY
1994 - 1996 (Sept.) – Vice President, Business Development
1994 - 1994 (July) – Louisville Gas & Electric Company, Louisville, KY
General Manager, Gas Operations

LG&E Energy Corp., Louisville, KY
1991 - 1993 – Director, Business Development
Koch Industries Inc.
1990 - 1991 – Koch Membrane Systems, Boston, MA
National Sales Manager, Americas
1989 - 1990 – John Zink Company, Tulsa, OK
Vice President, International
Lone Star Technologies (a former Northwest Industries subsidiary)
1988 - 1989 – John Zink Company, Tulsa, OK
Vice Chairman
1986 - 1988 – Hydro-Sonic Systems, Dallas, TX
General Manager
1986 – 1986 (July) — Ft. Collins Pipe, Dallas, TX, General Manager
1985 - 1986 – Lone Star Technologies, Dallas, TX
Assistant to Chairman
1980 - 1985 – Northwest Industries, Chicago, IL
Manager, Financial Planning

**Exhibit PWT-1**

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER03-1118-000** |

**MOTION TO INTERVENE
AND JOINT PROTEST OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY**

Pursuant to Rules 214 and 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.214, § 385.211 (2002), and the Commission's Notices issued July 30, 2003 and August 7, 2003, Louisville Gas and Electric Company and Kentucky Utilities Company (collectively referred to as "LG&E/KU" or "Companies") hereby move to intervene in the above-captioned proceeding, and protest the filing submitted therein on July 25, 2003, by the Midwest Independent Transmission System Operator, Inc. ("MISO"). In support, LG&E/KU state as follows:

**MOTION TO INTERVENE**

1. Communications and correspondence related to this filing should be directed to the following representatives of LG&E/KU:

Michael S. Beer
Vice President, Rates and Regulatory
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202
(502) 627-3547

Paul W. Thompson
Senior Vice President, Energy Services
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202
(502) 627-3861

Linda S. Portasik
Senior Corporate Attorney
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202
(502) 627-2557

2. LG&E/KU are vertically integrated utilities located principally in Kentucky that together serve approximately 850,000 customers throughout the state. The Companies, whose combined transmission and generating capacity exceeds 26,000 MVa and 8,800 MW, respectively, are among the original transmission-owning members of the MISO. LG&E/KU, along with all other transmission-owning members of MISO, transferred control of their transmission facilities to MISO effective February 1, 2002.

3. On July 25, 2003, the MISO filed Volume No. 1 of its Open Access Transmission and Energy Markets Tariff ("TEMT"), which will govern the implementation and operation of MISO's Day-Ahead and Real-Time Energy Markets. As transmission-owning members of MISO that currently enjoy retail electric rates among the lowest in the country, LG&E/KU will be directly affected by and have a significant interest in this proceeding -- particularly to the extent certain provisions of MISO's proposed TEMT threaten to deprive LG&E/KU of much needed operational flexibility otherwise afforded under existing federal legislative and regulatory initiatives. This interest cannot be adequately represented by any other party.

4. For the foregoing reasons, LG&E/KU respectfully request that they be granted intervention in this proceeding, with full rights attendant to party status.

## PROTEST

### I. MISO's Filing Should Be Rejected as Premature In Light of Impending Legislation and the FERC's Latest Pronouncements.

In addition to the concerns expressed below with regard to specific provisions of MISO's proposed TEMT (*see* Part II), LG&E/KU strongly object to MISO's apparent attempt to exempt itself and its members from the dictates of current legislative and regulatory initiatives, to the detriment of Load Serving Entities' ("LSEs") native load customers. MISO's proposed TEMT is fundamentally flawed in this regard in that -- contrary to these initiatives (*see* below) -- it deprives LG&E/KU of the operational flexibility they currently enjoy and must retain to avoid potentially significant harmful effects on native load. Specifically, the TEMT incorporates a mandatory Firm Transmission Right ("FTR") allocation methodology that requires LSEs to replace their existing "physical" rights to firm transmission service with financial rights (and obligations) based on a previously determined snapshot of optimal generation dispatch.

Contrary to MISO's earlier assertions (made prior to the instant filing in an effort to gain stakeholder consensus on the filing), LG&E/KU dispute any notion that the Companies can achieve the same degree of operational flexibility and coverage under MISO's proposed TEMT that the Companies currently enjoy as recipients of network transmission service under MISO's existing Network Service Tariff. Currently, not only do LG&E/KU have the flexibility to change generation up to 12:00 noon the day prior to "real time" without penalty (as MISO acknowledges), the Companies may also serve their network load on a firm basis from any of their "Designated Resources" in real time, again with no financial penalty. These Designated Resources include LG&E/KU's entire fleet of generation within the combined Companies' control area. By contrast, under MISO's proposed TEMT -- even under the most favorable FTR allocation scenario -- LG&E/KU's FTR rights are tied to specific LG&E/KU generators, based on a snapshot of optimal generation dispatch taken as much as one year in advance. Whenever, and for whatever reason, real time dispatch differs from the prior year's optimal snapshot, LG&E/KU and their native load customers face exposure to as yet unknown congestion costs that could well accumulate on an annual basis into the millions of dollars. LG&E/KU believe that MISO's TEMT can offer the same flexibility currently enjoyed by LG&E/KU only if FTR *options* are allocated from *all* current designated network resources, or, alternatively, if LSEs are permitted to retain their existing firm physical service rights.[1]

Federal legislative initiatives strongly support LG&E/KU's position in this regard. As the Commission is aware, bills introduced in both the United States House of Representatives (which bill has passed) and the United States Senate expressly recognize the importance of preserving the operational flexibility historically afforded to LSEs for the purpose of maintaining historical native load priorities.[2] Importantly, however, one of these initiatives -- the bill passed by the House -- includes a "safe harbor" provision that would permit MISO to implement its proposed allocation methodology upon receipt of FERC approval. Accordingly, unless such "safe harbor" language is removed from the legislation ultimately enacted by both Houses of Congress (during conference committee review), MISO's proposed TEMT would, if adopted herein, deprive LG&E/KU of the significant benefits otherwise afforded by this legislation, contrary to all notions of equity and logic.

The FERC's White Paper issued April 28, 2003, likewise supports LG&E/KU's position as regards firm transmission rights. Therein, the FERC recognized that LSEs should have the option of retaining existing native load transmission service, in lieu of obtaining FTRs. White Paper, *Wholesale Power Market Platform*, issued April 28, 2003, at 10. Clearly, the FERC's

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[1] The risks associated with MISO's TEMT are not limited to those described above. In particular, most of the allocated FTRs within MISO will likely be in the form of obligations. These obligations carry with them financial risk that does not exist today, and will likely result in LSEs opting for less than 100% of peak load FTR coverage as a means of reducing such financial exposure. In this regard, LG&E/KU are particularly troubled by MISO's proposal to impose a high minimum FTR take requirement based on a system capacity factor that, in LG&E/KU's case, would impose obligations even for the 10% of LG&E/KU-generated power destined for other LSEs' loads.

[2] *See* 108th Congress, H.R. 4 (as passed by the House), Electricity Title, Section 16023; 108th Congress, S. 14 (as reported by the Senate Energy & Natural Resources Committee), Electricity Title, Section 1131.

latest pronouncement is significant to LSEs like LG&E/KU that do not equate FTRs with physical transmission rights.

At bottom, at a time when Congress and the FERC may well be redefining what federal law requires, it is premature and entirely inappropriate to accept MISO's TEMT filing. Because the tariff, by its terms, exposes LG&E/KU to conditions contrary to those envisioned by current legislative and regulatory initiatives, it is patently deficient, and should be rejected pending final resolution of these issues in Congress and the federal rulemaking arena.[3]

**Conclusion**

For the above-stated reasons, LGE/KU protest MISO's filing herein and request that it be summarily rejected.

Respectfully submitted,

/s/LSP

Linda S. Portasik
Attorney for
Louisville Gas and Electric Company and
Kentucky Utilities Company

Michael S. Beer
Vice President, Rates and Regulatory
Louisville Gas and Electric Company and
Kentucky Utilities Company

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[3] LG&E/KU were aware of the aforementioned risks when participating in the Transmission Rights Task Force and other relevant stakeholder fora. However, it is one thing to accept these risks in the good faith belief that federal law, as set forth in the FERC's Standard Market Design rules, will require such acceptance. It is quite another to be required to accept such risks after FERC has made clear, in its recent White Paper, that significant portions of the FERC's proposed Standard Market Design should no longer apply. Although some members of the FERC staff did indeed indicate in April 2003, that the FERC's White Paper is not intended to apply to MISO, there is no legal basis for such an unduly discriminatory distinction; it is axiomatic that FERC's final market rules will apply -- intended or not -- to every FERC-jurisdictional region that has not already sought and received FERC approval of an ISO tariff.

LG&E ENERGY

**Paul W. Thompson**
*Senior Vice President*
*Energy Services*

**LG&E Energy Corp.**
*220 West Main Street*
*P.O. Box 32030 (40232)*
*Louisville, Kentucky 40202*
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*Fax: 502-627-2995*

May 23, 2003

Mr. James P. Torgerson
President and CEO
Midwest Independent Transmission System Operator
701 City Center Drive
Carmel, Indiana 46032

Re: *MISO's "Day 2" Open Access Transmission Tariff*

Dear Jim:

As you know, the Midwest Independent Transmission System Operator ("MISO") is planning to file its "Day 2" Open Access Transmission Tariff ("OATT") with the Federal Energy Regulatory Commission ("FERC") in mid-June, and, to this end, released for comment earlier this month a draft version of such tariff. Please be advised that Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") take strong exception to MISO's proposed June 20, 2003 OATT filing. LG&E/KU's objection to the draft OATT centers primarily on the conflict between the draft OATT and the FERC's latest (and, we believe, more equitable) stance regarding the allocation of native load transmission rights.

More specifically, the draft OATT largely incorporates the mandatory Firm Transmission Rights ("FTRs") allocation methodology proposed in the FERC's Standard Market Design ("SMD") Notice of Proposed Rulemaking, which methodology requires Load Serving Entities ("LSEs") to replace their "physical" rights to firm transmission service with FTRs. However, as you know, the FERC, in its wholesale market platform white paper issued April 28, 2003, recognized that LSEs should have the option of retaining existing native load transmission service, in lieu of obtaining FTRs. The FERC's latest pronouncement is significant to LSEs (like LG&E/KU) that do not equate FTRs with physical transmission rights.

You may recall also that a bill recently passed in the United States House of Representatives (H.R. 6, Section 217) expressly "carves out" transmission capacity for native load service, recognizing the importance of native load scheduling priorities. However, this same legislative initiative includes a "safe harbor" provision that would permit MISO to implement its proposed methodology if approved by FERC. Coupled with MISO's proposed Day 2 OATT filing, such a safe harbor provision would unfairly deprive LG&E/KU of the operational flexibility otherwise afforded by this legislation, to the detriment of their native load.

At a time when FERC is, and Congress may well be, redefining what federal law requires, LG&E/KU believe it is nothing short of reckless for MISO to file a Day 2 OATT that would impose on LG&E/KU costs and obligations that, while previously thought necessary to comply with federal law, now appear avoidable, particularly in light of genuine concerns already voiced by MISO members (as expressed in the motion filed recently with the MISO Advisory Committee seeking delay of the filing). In this regard, although MISO's press release concerning this week's Day 2 OATT technical conference described a "spirited debate" over the details of the draft OATT, the press release fails to mention that a significant portion of that debate centered on the appropriateness of making any such filing at this juncture in light of current regulatory and legislative uncertainty.

Because MISO's Day 2 OATT filing threatens to harm needlessly LG&E/KU, LG&E/KU will have no choice but to object strongly to any tariff filing submitted by MISO that fails to take into account FERC's latest wholesale power market platform requirements.

Very truly yours,

Paul W. Thompson
Senior Vice President Energy Services
LG&E Energy Corp.

PWT/lp

cc: Thomas M. Dorman, Executive Director
Kentucky Public Service Commission

Michael Small
Wendy Reed
Wright & Talisman, P.C.

James Keller, MISO Chairman Advisory Committee

LG&E ENERGY

Paul W. Thompson
Senior Vice President
Energy Services

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*(Letter sent electronically and by standard mail)*

July 11, 2003

Mr. James P. Torgerson
President and CEO
Midwest Independent Transmission System Operator
701 City Center Drive
Carmel, Indiana 46032

Re: *MISO's "Day 2" Open Access Transmission Tariff*

Dear Jim:

Thank you for your letter dated June 2, 2003. Although, for the reasons set forth in our May 23, 2003 correspondence, Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") continue to object to the Midwest Independent Transmission System Operator's ("MISO") proposed "Day 2" Open Access Transmission Tariff ("OATT") filing, we do appreciate MISO's decision to delay its filing until July 25, 2003. LG&E/KU's objections arise primarily as a result of FERC's apparent relaxation of the mandatory requirements for standard market design set forth in the "White Paper," and continuing concerns with the workability of the current market design.[1] With that said, I would like to respond briefly to certain points raised in your June 2, 2003 letter.

First, I must dispute the notion that LG&E/KU can achieve "the same degree of operational flexibility and coverage" in MISO's proposed Day 2 market that the Companies currently enjoy as recipients of network transmission service. Under the existing MISO Network Service Tariff, not only do LG&E/KU currently have the flexibility to change generation up to 12:00 noon the day prior to "real time" without penalty (as you note), LG&E/KU may also serve their network load on a firm basis from any of their "Designated Resources" in real time, again with no financial penalty. These Designated Resources include LG&E/KU's entire fleet of generation within the combined Companies' control area. By contrast, in MISO's proposed Day 2 market -- and under the most favorable Firm Transmission Rights ("FTR") allocation scenario

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[1] These concerns include the hourly optimized objective function of the MISO proposed day ahead Security Constrained Economic Dispatch and post day ahead Reliability Assessment Commitment process, and the lack of clear delineation between Control Area/MISO/Market Participant functions - concerns most recently brought to light in the July 10, 2003 letter from the Market Protocols Task Force to Ron McNamara.

-- LG&E/KU's FTR rights are tied to specific LG&E/KU generators, based on a snapshot of optimal generation dispatch taken as much as one year in advance. Whenever, and for whatever reason, real time dispatch differs from the prior year's optimal snapshot, LG&E/KU face exposure to as yet unknown congestion costs that could well accumulate on an annual basis into the several millions of dollars. LG&E/KU believe that MISO's Day 2 market can offer the same flexibility currently enjoyed by LG&E/KU only if FTR *options* are allocated from *all* current designated network resources, or, alternatively, if LSEs are permitted to retain their existing firm physical service rights. Contrary to MISO, LG&E/KU firmly believe the White Paper provides for the latter option.

The risks associated with MISO's Day 2 Market Design are not limited to those described above. In particular, most of the allocated FTRs within MISO will likely be in the form of obligations. These obligations carry with them financial risk that does not exist today, and will likely result in LSEs opting for less than 100% of peak load FTR coverage as a means of reducing such financial exposure. In this regard, LG&E/KU are particularly troubled by MISO's proposal to impose a high minimum FTR take requirement based on a system capacity factor that, in LG&E/KU's case, would impose obligations even for the 10% of LG&E/KU-generated power destined for other LSEs' loads.

As participants in the Transmission Rights Task Force and other relevant stakeholder forums, LG&E/KU have not been unaware of the aforementioned risks. However, it is one thing to accept these risks in the good faith belief that federal law, as set forth in the FERC's Standard Market Design rules, will require such acceptance. It is quite another to be required to accept such risks after FERC has made clear, in its recent White Paper, that significant portions of the FERC's proposed Standard Market Design should no longer apply. Although some members of the FERC staff did indeed indicate last month that the FERC's White Paper is not intended for MISO, which we find puzzling, it is clear that FERC's final market rules will apply -- intended or not -- to every FERC-jurisdictional region that has not already sought and received FERC approval of an ISO tariff.

In light of the above-noted risks, as well as the ongoing uncertainties created by recent legislative action, as described in my letter of May 23, 2003, LG&E/KU cannot support MISO's proposed Day 2 Tariff, and instead we strongly support the motion currently pending before the MISO Advisory Committee to delay the filing of such tariff. MISO's stakeholders have every right to know what constitutes minimal compliance under federal law before deciding whether to obligate themselves and their customers to more than be necessary, as MISO proposes. MISO would be far better served and would far better serve its members by taking the time necessary to fully weigh the costs and benefits associated with a market design that promises to impose uncertain and likely enormous financial costs upon MISO stakeholders -- a design that FERC obviously no longer intends to mandate.

Thank you again for your timely response. LG&E/KU will, of course, continue to contribute to the development of a cost effective Midwest market that fully complies with federal requirements. To that end, LG&E/KU, as stakeholders, intend to continue their efforts to ensure that the Midwest markets incorporate that level of federal compliance that optimizes the balance between regional costs and benefits.

Very truly yours,

Paul W. Thompson

PWT/lp

cc: Thomas M. Dorman, Executive Director, Kentucky Public Service Commission
James Keller, MISO Chairman Advisory Committee
Wendy Reed, Wright & Talisman, P.C.
Michael Small, Wright & Talisman, P.C.

**Exhibit PWT-2**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER02-2595-000** |

**MOTION TO INTERVENE**
**AND JOINT PROTEST OF**
**LOUISVILLE GAS AND ELECTRIC COMPANY**
**AND KENTUCKY UTILITIES COMPANY**

Pursuant to Rules 214 and 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.214, § 385.211 (2002), and the Commission's "Notice of Filing" issued September 27, 2002, Louisville Gas and Electric Company and Kentucky Utilities Company (collectively referred to as "LG&E/KU" or "Companies") hereby move to intervene in the above-captioned proceeding, and protest the filing submitted therein by the Midwest Independent Transmission System Operator, Inc. ("MISO"). In support, LG&E/KU state as follows:

## MOTION TO INTERVENE

I.

Communications and correspondence related to this filing should be directed to the following representatives of LG&E/KU:

Linda S. Portasik
Senior Corporate Attorney
LG&E Energy Corporation
220 W. Main Street
Louisville, KY 40202
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linda.portasik@lgeenergy.com

Michael S. Beer
Vice President, Rates and Regulatory
LG&E Energy Corporation
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II.

LG&E/KU are vertically integrated utilities located principally in Kentucky that together serve approximately 850,000 customers throughout the state. The Companies, whose combined transmission and generating capacity exceeds 26,000 MVa and 8,800 MW, respectively, are among the original transmission-owning members of the Midwest Independent Transmission System Operator, Inc. ("MISO"). LG&E/KU, along with all other transmission-owning members of MISO, transferred control of their transmission facilities to MISO effective February 1, 2002.

III.

By its filing, MISO proposes to implement a new Schedule 16 to recover costs associated with the implementation and administration of Financial Transmission Rights ("FTRs"), and a new Schedule 17 to recover costs associated with the development, implementation and operation of various energy markets. According to MISO, "[t]he acquisition of necessary systems and the terms and conditions of required financing will be dependent upon securing firm regulatory approval of cost recovery." Transmittal Letter at 1.

IV.

As transmission-owning members of MISO that currently enjoy retail electric rates among the lowest in the country, LG&E/KU will be directly affected by and have a significant interest in this proceeding -- particularly given the enormity of MISO's projected expenditures and the lack of any meaningful review or oversight of planned/actual cost expenditures. This interest cannot be adequately represented by any other party. For these reasons, LG&E/KU respectfully request that they be granted intervention in this proceeding, with full rights attendant to party status.

## PROTEST

### I. The Commission Must Ensure That MISO's Charges Under Schedules 16 and 17 Properly Match Cost Responsibility With Cost Causation.

LG&E/KU join and fully support the "Protest and Motion to Intervene of the Midwest ISO Transmission Owners" filed separately in this docket on October 15, 2002 ("TO Protest"). However, given the Companies' unique position as the lowest–cost utilities in the nation -- and the enormous cost responsibility already foisted on the Companies for amorphous "benefits" grounded more in rhetoric than fact[1] -- LG&E/KU believe it is imperative to point out, once again, the importance of matching cost responsibility with cost causation and benefit. Quite simply, LG&E/KU cannot be placed (once again) in the untenable position of shouldering costs properly borne by others. Unfortunately, however, MISO's latest proposal does precisely that, in at least two respects.

1. The proposed charges under MISO's proposed Schedules 16 and 17 simply do not reflect a proper alignment of cost responsibility and cost causation/benefit. Instead, with respect to proposed Schedule 17, MISO proposes to impose a significant share of "energy market" costs on vertically integrated utilities that serve load largely from generation within their control area – *e.g.*, LG&E/KU. Clearly, these utilities'

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[1] *See, e.g.*, Joint Brief of Petitioners and Intervenors in Support of Petitioners, Case Nos. 02-1121 and 02-1122, United States Court of Appeals for the District of Columbia Circuit), filed September 19, 2002, at pp. 52-60.

reliance on real-time and/or next-day energy markets will not begin to approach the reliance of other, more "market-dependant" entities. To better reflect principles of cost causation -- and ensure that vertically integrated utilities are not being targeted for cost recovery simply because they are the easiest target[2] -- MISO must be required to recover at least a portion of its Schedule 17 costs via a "transaction" fee, as explained in the TO Protest. Similarly flawed is MISO's Schedule 16 cost recovery proposal, as MISO makes no distinction, for purposes of determining/allocating cost responsibility, between entries that hold FTRs but do not participate in the energy market, and those that do so participate. Again, the Commission should direct MISO to implement transaction-based charges to recover Schedule 16 costs.

In addition to the charges underlying Schedules 16 and 17, MISO's proposed new "exit" fee, to be imposed on all "withdrawing" transmission owners, grossly distorts -- and, in fact, disregards entirely -- principles of cost causation. MISO proposes to impose an exit fee on all withdrawing transmission owners based on each owner's load ratio share of costs not previously recovered, including deferred costs, undepreciated capital expenditures and financing costs. MISO rationalizes the exit fee as a means of "assur[ing] financing" for the development of the services provided under Schedules 16 and 17 and "offset[ting] lost revenues and additional costs associated with a changing RTO configuration" resulting from a member's withdrawal. Transmittal Letter at 13-14. As pointed out in the TO Protest, MISO acknowledges that these reasons have nothing to

[2] MISO should not be permitted to impose such significant costs on vertically integrated utilities simply because MISO's potential bond holders insist on revenue certainty and integrated utilities are MISO's easiest target.

do with cost causation. Indeed, MISO has made no attempt to show that the costs it seeks to recover through the exit fee bear any relation whatsoever to costs incurred to serve the exiting member. Instead, the exit fee is nothing more than a draconian penalty charged to withdrawing members – serving as a "hook" to keep current members "on board" even if subsequent events (initiated by FERC, MISO, other RTOs or other members) dictate that a member transition to another RTO. At bottom, the exit fee not only runs far afoul of cost causation principles, it may prevent the FERC from achieving its ultimate goal of a well-coordinated, seamless regional market.

## II. The Commission Must Implement Safeguards To Ensure That MISO's Costs Are Prudently Incurred.

Just as the Commission must ensure that MISO's costs are properly allocated among transmission users, it likewise – and just as importantly – must ensure that these costs are prudently incurred. It is ludicrous to suggest that the Commission would afford any regulated entity *carte blanche* spending authority. However, unless appropriate measures are put in place to ensure that MISO has adopted the most cost-effective means of providing its proposed services, and is incurring costs prudently on an ongoing basis, the Commission may well be affording just that authority to MISO. In addition to the investigation proposed in the TO Protest, LG&E/KU urge the Commission to undertake a regular review of MISO's expenditures and spending practices.

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## CONCLUSION

For the above-stated reasons, LGE/KU protest the filing submitted by MISO in the above-referenced docket..

Respectfully submitted,

/s/LSP

Linda S. Portasik
Attorney for
Louisville Gas and Electric
Company and
Kentucky Utilities Company

Michael S. Beer
Vice President, Rates and Regulatory
Louisville Gas and Electric
Company and
Kentucky Utilities Company

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER02-2595-001** |

**COMMENTS OF**
**LOUISVILLE GAS AND ELECTRIC COMPANY**
**AND KENTUCKY UTILITIES COMPANY**
**ON INFORMATIONAL FILING**

Pursuant to Rule 213 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385.213, Louisville Gas and Electric Company and Kentucky Utilities Company (collectively referred to as "LG&E/KU" or "Companies") respectfully submit these comments on the informational filing submitted herein by the Midwest Independent Transmission System Operator, Inc. ("MISO") on December 23, 2002, in response to the Commission's order in this proceeding issued November 22, 2002 ("November 22 Order").[1] *See* Midwest Independent Transmission System Operator, Inc., 101 FERC ¶ 61,221 (2002). LG&E/KU have intervened in and protested the filing initiating this proceeding, by which MISO has now implemented, subject to refund and "paper hearing" procedures, (i) a new Schedule 16 to recover costs associated with the implementation and administration of Financial Transmission Rights ("FTRs"), and (ii) a new Schedule 17 to recover costs associated with the development, implementation and operation of various energy markets. *See Motion to Intervene and Joint Protest of Louisville Gas and Electric Company and Kentucky Utilities Company*, Docket No. ER02-2595-000, October 15, 2002.

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[1] LG&E/KU join in and fully support the comments filed concurrently herein by the MISO Transmission Owners.

**COMMENTS**

Cognizant of its obligation to allow recovery of only "prudently incurred costs" (November Order at 11), the Commission in its November 22 Order required MISO, among other things, to (i) explain the alternative means that MISO considered to accomplish the implementation tasks in connection with Schedules 16 and 17; and (ii) "provide a detailed breakdown of the total start-up costs." November 22 Order at 12. In the former regard, MISO has failed to justify its unilateral decision to develop the infrastructure and applications underlying the "Midwest Market Initiative" internally and entirely from scratch.[2] Noting only that outsourcing the development of such infrastructure and applications to existing entities "would be inappropriate" because "there is not an effective market of outsourcing suppliers" (MISO Report at 2), MISO not only fails to provide any support for such an assertion, but also refuses to address the obvious question of why systems from established markets (*e.g.*, Automated Power Exchange) cannot be used, at least in part, in furtherance of the Midwest Market Initiative.

Equally deficient is MISO's "breakdown" of total start-up costs. For example, MISO "breaks down" estimated capital outlays totaling nearly $58 million into three broad categories, one of which bears the obscure label "development/consulting" (totaling nearly $34 million). No where does MISO explain what $34 million of "development/consulting" entails, or why this amount is justified (*e.g.*, how many consultants is MISO using, how were they selected, what are the deliverables?) Simply providing cost estimates for, *e.g.*, "development/consulting," cannot allow for a proper determination of whether, in fact, such expenditures are least-cost, prudent

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[2] *See also* the comments filed concurrently herewith by the MISO Transmission Owners.

expenditures. Moreover, MISO fails to explain why an additional $14 million in "hardware" costs is necessary, particularly in light of existing platforms and systems (for which minor changes in functionality might have been an option).

## CONCLUSION

LG&E/KU urge the Commission to direct MISO to respond fully and in detail to the Commission's directives as set forth in its November 22 Order, to allow a thorough and meaningful review of MISO's estimated expenditures and the prudence thereof. It is imperative, given the enormity of these costs and the unforeseen financial burden already foisted on existing transmission owners, that the Commission be able to scrutinize fully MISO's spending in accordance with historical prudence standards.

Respectfully submitted,

/s/LSP

Linda S. Portasik
Attorney for
Louisville Gas and Electric
Company and
Kentucky Utilities Company

Michael S. Beer
Vice President, Rates and Regulatory
Louisville Gas and Electric
Company and
Kentucky Utilities Company

Testimony

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

SEP 22 2003

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
MICHAEL S. BEER
VICE PRESIDENT, RATES AND REGULATORY
LG&E ENERGY CORP.

Filed: September 22, 2003

**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 Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively referred at times as "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my qualifications is attached as an Appendix hereto.

**Q. Have you previously testified before this Commission?**

A. Yes. I testified before the Kentucky Public Service Commission ("KPSC") on 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.

A: My testimony addresses the following issues raised by the KPSC's order initiating this proceeding on July 17, 2003 ("July 17 Order"). First, I will discuss the regulatory environment giving rise to and currently surrounding LG&E's and KU's membership in the Midwest Independent Transmission System Operator, Inc. ("MISO"). Second, based on the results of the independent cost-benefit analysis performed by Christensen Associates at the Companies' direction and filed with the testimony of Mr. Mathew J. Morey in this proceeding, I will discuss the federal regulatory obstacles, and potential risks to the Companies and their customers, associated with pursuing an exit from MISO, even at the direction of the KPSC. Third, as directed by the July 17 Order, I will discuss the applicability of KRS Section 278.020(4) to the transfer of operational control over the Companies' transmission assets to MISO effective February 1, 2002. Finally, again pursuant to the July 17 Order, I will discuss the appropriateness of, and jurisdictional basis for, shifting decision-making regarding resource adequacy and demand response to regional organizations such as MISO. The remaining issues identified in the July 17 Order (the costs and benefits of the Companies' membership in MISO and the feasibility of joining a southern Regional Transmission Organization) are addressed in Mr. Morey's testimony.

## I. <u>MISO REGULATORY ENVIRONMENT</u>

**Q: Please describe the federal regulatory environment leading up to and currently surrounding LG&E's and KU's membership in MISO.**

A: In an effort to "remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to competitive bulk power markets," the Federal Energy Regulatory Commission ("FERC") in 1996 issued Order No. 888, wherein it required all public utilities owning, controlling or operating transmission facilities, including LG&E and KU, to offer unbundled, non-discriminatory transmission service to all third-parties under a single "open-access" transmission tariff. In that same rule, the FERC introduced the concept of Independent Transmission System Operators ("ISO") -- independent, third-party operators of regional transmission systems. The FERC encouraged transmission-owning electric utilities such as LG&E and KU to "explore the ISO model" as a means of ensuring that their provision of transmission service would meet the non-discriminatory, open-access requirements of Order No. 888.

The FERC later built on these initiatives in Order No. 2000, issued in early 2000. Believing that Regional Transmission Organizations ("RTOs") -- including both ISOs and other independent regional entities with more flexible governance and business structures -- "could successfully address the existing impediments to efficient grid operation and competition," the FERC in Order No. 2000 again urged (but did not require) transmission owning public utilities to transfer control of their transmission assets to RTOs. Most recently, in its Standard Market Design initiative begun in the fall of 2002, the FERC has proposed to strengthen and build even further on its regional competitive market policies by establishing RTOs and ISOs throughout the country as the foundation for standardized wholesale electricity markets: RTOs and ISOs would not only operate the transmission grid, but would monitor and operate regional energy markets, to ensure "transparent prices and market structures that will reliably produce just and reasonable prices."

**Q: Was MISO a product of the FERC's Order No. 888 regulatory initiative?**

A: Yes. In fact, the formation of MISO began in late 1995, and was evolving rapidly at the time LG&E and KU were finalizing their merger in late 1997. As Mr. Thompson explains in his testimony, LG&E and KU, along with several other Midwestern utilities, actively participated in MISO's creation, *albeit* for different reasons. LG&E's and KU's interests, for example, were driven largely by the desire to accommodate FERC's evolving policies regarding ISOs as announced in Order No. 888, as well as the desire to manage more efficiently regional transmission service under FERC Order No. 888.

After several years of negotiation and debate among affected stakeholders, including LG&E and KU, MISO ultimately became the first FERC-approved, functional ISO in 2001, commencing operations on February 1, 2002. As negotiated and agreed to by all participants, the terms and conditions of MISO membership were initially acceptable to the Companies and, at least in part, to the KPSC. Unfortunately, however, the FERC has since changed the rules of the game, to the detriment of LG&E, KU and their customers. Mr. Thompson discusses these changed circumstances at length in his testimony.

**Q: Did the FERC address MISO membership in its order approving LG&E's and KU's merger application in 1998?**

A: Yes. In finding that the merger would have no material impact on competition in the wholesale power market, the FERC relied heavily on the Companies' "continued participation" in MISO. The FERC stated:

> In this case, LG&E and KU have joined the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and filed for approval to transfer operational control over their transmission facilities to the Midwest ISO. We find that the proposed mitigation measures and ratepayer protection mechanisms, in conjunction with LG&E's and KU's participation in the Midwest ISO, will ensure that the merger will not adversely affect competition, rates or regulation. On this basis, we will approve the merger without further investigation.

82 FERC ¶61,308 (1998), Docket No. EC98-2-000, Order issued March 27, 1998, slip op. at 1-2. That same order, although acknowledging the Companies' right to seek an exit from MISO, made clear the FERC's authority to revisit the competitive ramifications of that decision:

> We regard LG&E and KU's participation as parties in the Midwest ISO filings as evidence of their commitment to membership in the Midwest ISO. Our approval of the merger is based on LG&E and KU's continued participation in the Midwest ISO. If LG&E and KU seek permission to withdraw from the Midwest ISO proceeding or the ISO once it is operating, we will evaluate that request in light of its impact on competition in the KU destination markets, use our authority under section 203(b) of the FPA to address any concerns, and order further procedures as appropriate.

*Id.*, slip op. at 37.

**Q: Did the FERC make similar findings in approving the Companies' merger with Powergen plc and E.ON AG in 2000 and 2001, respectively?**

A: The FERC did not explicitly address this issue in its order approving the Companies' merger with Powergen plc. However, in its order approving LG&E's and KU's merger with E.ON AG (through Powergen plc), the FERC relied at least in part on the Companies' commitment to remain members of MISO at least until the end of 2002, and to be members of a FERC-approved RTO thereafter. Specifically, the FERC stated:

> As Applicants note, LG&E and KU have committed to transfer operational control of their transmission systems to the MISO and will remain members of the Midwest ISO at least until the end of 2002. Furthermore, they have committed to members of a Commission-approved RTO thereafter. Therefore, they lack the ability to exploit their transmission assets to harm competition in wholesale electricity markets.

97 FERC ¶61,149 (2001), Docket No, EC01-115-000, Order issued October 15, 2001, slip op. at 12.

**Q: Did the KPSC also support LG&E's and KU's membership in MISO?**

A: Yes. In approving the PowerGen acquisition in May 2000, the KPSC encouraged LG&E and KU to continue to actively participate in MISO:

> Transmission capacity and reliability are also concerns to be addressed herein. Historically, LG&E and KU have actively participated in organizations such as the East Central Area Reliability Council and the Midwest Independent System Operator ("Midwest ISO") which help to ensure the reliability of the bulk power system and which, in turn, have a significant impact on retail electric service. The Commission encourages LG&E and KU to continue active participation in these organizations, particularly with respect to maintaining the reliability of the electricity supplied to their customers.

Case No. 2000-095, *Joint Application of Powergen plc. LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger,* Order at 22-23. In addition to this encouragement, the KPSC required LG&E and KU to accept the following commitment as an express condition to the KPSC's approval of Powergen's acquisition: "PowerGen commits that its present expectation is for LG&E and KU to remain members of the Midwest ISO." Appendix A, *Other Commitments and Assurances*, No. 15. A virtually identical commitment was made in the context of the E.ON acquisition: "E.ON and PowerGen commit that their present expectation is for LG&E and KU to remain members of the Midwest Independent System Operator." Case No. 2001-104, *Joint Application for the Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of Powergen plc*, Appendix A, *Other Commitments and Assurances, No. 49.* Both PowerGen and E.ON accepted these commitments and consummated their acquisitions based on their expectations that the KPSC's request for these commitments supported LG&E's and KU's continued membership in MISO.

## II POTENTIAL FEDERAL REGULATORY OBSTACLES TO MISO EXIT

**Q. Are LG&E and KU currently obligated by FERC to be members of MISO or another RTO?**

A. No, not by specific regulation. As noted, by its terms, the FERC's currently-effective RTO rule (Order No. 2000) makes RTO membership only "voluntary." However, the "voluntary" nature of RTO participation is questionable at best, as the FERC demonstrated only 10 days ago when it required certain utilities to "specify the impediments to their voluntary commitments to join RTOs; and propose solutions to these impediments, including [FERC] actions necessary to . . . establish a joint and common market in the Midwest and PJM region." *Order Announcing Commission Inquiry Into Midwest ISO-PJM RTO Issues*, Docket Nos. ER03-262-001, *et al.*, slip op.

at 4. Applying similar pressure to "volunteer" in other contexts, the FERC has suggested that a jurisdictional entity's failure to join an RTO could lead to certain indirect sanctions such as revocation of market-based rate authority and, in the Companies' case specifically, increased and/or renewed scrutiny of corporate restructuring transactions. Although I believe there is a small risk that the FERC would go so far as to strip the Companies of their market-based rate authority, I cannot rule out this potentiality, particularly given the FERC's current fervor for RTOs. Moreover, it is not at all clear what other new or different conditions the FERC could impose in reassessing the Companies' corporate restructurings.

**Q. If the FERC revoked LG&E's and KU's market-based rate authority, could the Companies' customers be harmed?**

A: Yes. Revocation of the Companies' market-based rate authority could hamper the Companies' ability to make off-system sales, from which customers currently derive a substantial benefit through base rate credits. The annual credit associated with off-system sales currently embedded in LG&E's and KU's base rates totals approximately $43 million. Although revocation of LG&E's and KU's market-based rate authority would not affect the Companies' ability to sell power into the wholesale market at cost-based rates, it is possible that, in this circumstance, base rates would need to be adjusted to remove at least some portion of this base rate credit. Similarly, the current level of off-system sales margins used in the calculation of the Earnings Sharing Mechanism could decline commensurate with any decline in bulk power sales due to the loss of market-based rate authority.

**Q. You also mentioned "increased scrutiny of corporate transactions." What do you mean by that?**

A. LG&E's and KU's withdrawal from MISO could prompt the FERC to revisit its orders approving LG&E's and KU's merger, as well as the Companies' merger with E.ON AG. As noted above, in finding that the LG&E/KU merger had no material impact on competition in the wholesale power market, the FERC relied on the Companies' "continued participation" in MISO, and clarified that "if LG&E and KU seek permission to withdraw" from MISO, the FERC would re-evaluate such impact and use its ongoing authority under FPA Section 203 (under which FERC examines and conditions mergers) "to address any concerns, and order further procedures as appropriate." Similarly, in its order approving LG&E's and KU's merger with E.ON AG, the FERC relied at least in part on the Companies' commitment to remain members of a FERC-approved RTO after 2002. Thus, any attempt to exit MISO at this juncture could trigger a reassessment of competitive impact in that context as well. Although unlikely, the FERC could also attempt to impose harsher sanctions, including the divesture of certain generation or transmission assets, as market power mitigation measures. Because the limits of the FERC's ongoing FPA Section 203 authority are relatively untested, it is unclear what new conditions the FERC might seek to impose should it elect to revisit one or both of these merger orders and ultimately find that new conditions are necessary in light of, and to make up for, the RTO "void."

**Q. Apart from the potential regulatory risks described above, do LG&E and KU have any contractual obligations that create additional risks?**

A. Yes. LG&E and KU are signatories to the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("MISO Agreement"). Under Article Seven of the MISO Agreement, should the KPSC order the withdrawal, LG&E and KU may, within 30 days of such action, withdraw from MISO, but must obtain FERC approval to do so under FPA Section 205.

**Q: What factors would the FERC consider in evaluating an application for withdrawal under FPA Section 205?**

A: Section 205 of the FPA requires only that the withdrawal be "just and reasonable." As I discussed above with respect to the FERC's "conditioning" authority under FPA Section 203, however, the limits of the FERC's authority under FPA Section 205 to condition its approval of a withdrawal application is untested. As a consequence, it is unclear what, if any, conditions, the FERC could attempt to impose as a condition to finding the Companies' withdrawal application "just and reasonable" under FPA Section 205.

**Q. Given the D.C. Circuit's recent decision in *Atlantic City Electric Co. v. FERC,* 295 F. 3d 1 (D.C. Cir. 2002), does the FERC still have the authority to require that entities obtain FERC approval prior to withdrawing from RTOs?**

A. Yes. That transmission owners must obtain FERC approval under FPA Section 205 does not conflict with *Atlantic City*. In that case, the United States Court of Appeals for the District of Columbia Circuit determined that FERC could not require jurisdictional public utilities to obtain FERC approval under FPA Section *203* prior to withdrawing their RTO membership. Relying on the plain language of Section 203, the Court reasoned that joining or exiting RTOs, because its involves only the transfer of *operational* control over transmission facilities and not the transfer of *ownership or* *physical control* of such assets, does not constitute a "disposition" of facilities within the meaning of, and sufficient to trigger FERC's jurisdiction under, Section 203. *Atlantic City* did not find that FERC lacked authority to determine whether a utility's withdrawal from an RTO is "just and reasonable" under Section 205. The FERC recently clarified this point in a "guidance" statement issued September 10, 2003, in Docket No. PL03-5-000.

Q. **Would the Companies' withdrawal from MISO require LG&E and KU to incur any costs under the terms of the MISO Agreement?**

A: Yes, withdrawal would trigger the imposition of an exit fee under the MISO Agreement. Pursuant to the Transmission Owners Agreement, "[a]ll financial obligations and payments applicable to time periods prior to the effective date of [the withdrawing member's] withdrawal shall be honored by" MISO and the withdrawing member. MISO Agreement, Article Five, Section II(B). As of the current date, MISO has approximately $233 million in undepreciated capital expense (although it is seeking to borrow another $125 million). LG&E and KU are currently responsible for approximately 8% of the transmission load. Although it is difficult to determine precisely the amount of such fee, Mr. Morey has estimated the Companies' exit fee obligations at approximately $23 million.

Q: **Would the Companies request recovery of the exit fee from customers?**

A: Yes. The Companies would seek recovery of both the exit fee and, pending receipt of all necessary regulatory approvals, all costs incurred in connection with the Companies' ongoing membership obligations. Recovery would be properly timed to protect against over- or under- recovery at any one point in time (*i.e.*, concurrent recovery of ongoing costs and exit fee costs). Specifically, if the KPSC accepts the Companies' exit proposal as described by Mr. Thompson, LG&E and KU would request the KPSC to permit the Companies to establish in this proceeding a regulatory asset for the MISO exit fee. The Companies would seek authorization in their next base rate case to include in base rates all MISO-related expenses (as reflected in the test period), as well as all *pro forma* adjustments, pending receipt of final FERC approval to exit MISO. Upon receipt of all necessary approvals for exit, the Companies would take the requisite ratemaking steps (through a filing with the KPSC) to remove the MISO-related expenses from base rates, and begin amortization and base rate recovery of the regulatory asset over a specific (*e.g.*, 5-year) term.

## III APPLICABILITY OF KRS 278.020(4) TO THE TRANSFER OFFUNCTIONAL CONTROL OVER TRANSMISSION FACILITIES

**Q: The July 17 Order directs the Companies to address the "applicability of the transfer-of-control statute, KRS 278.020(4), to LG&E's and KU's transfer of their respective transmission assets" to MISO upon commencement of their membership in 1998. Would you explain why LG&E and KU did not seek KPSC approval prior to transferring the necessary functional control to MISO?**

A: Yes. LG&E did not seek prior KPSC approval for such transfer for two reasons, both of which rely on a fair reading of Section 278.020(4), the only "transfer of control" statute in effect when the Companies' made the transfer. Section 278.020(4) reads as follows:

> No person shall acquire or transfer ownership of, *or control, or the right to control, <u>any utility</u>* under the jurisdiction of the commission by sale of assets, transfer of stock, or otherwise, or abandon the same, without prior approval by the commission. The commission shall grant its approval if the person *<u>acquiring the utility</u>* has the financial, technical, and managerial abilities to provide reasonable service.

Kentucky Revised Statutes § 278.020(4) (emphasis added). *First,* by its terms, the focus of this section is the transfer of control of any "utility" as opposed to the transfer of control over certain physical assets of the utility. The word "utility" is defined as any person [including any corporation] who "owns, controls, operates, or manages any facility" used in connection with the transmission of electricity. *See* Kentucky Revised Statutes § 278.010(2). Because the Companies' transfer to MISO involved only the limited right to operate certain utility *assets* -- and not a transfer of ownership or control of the corporate entity -- the Companies reasonably believed that Section 278.020(4) did not apply to the transfer at issue.

Indeed, that Section 278.020(4) does not, on its face, govern the transfer of utility *assets* -- or as is the case here, the right to share in the operation of those assets -- is evidenced by the fact that the Kentucky General Assembly found it necessary to enact an entirely separate statutory provision (effective April 2002, after completion of the Companies' transfer) that expressly so governs. *See* KRS § 278.218(1). The relevant portion of the recently enacted legislation reads as follows:

> No person shall acquire or transfer ownership of or control, or the right to control, *any assets that are owned by a utility* as defined under KRS 278.010(3)(a) without prior approval of the commission, if the assets have an original book value of one million dollars ($1,000,000) or more . . . .

Kentucky Revised Statutes § 278.218(1) (emphasis added). The General Assembly would not have enacted this new section of the law had Section 278.020(4) governed the identical subject matter.

*Second,* even if Section 278.020(4) could be interpreted broadly enough to encompass the transfer of control of utility assets, the Companies have never relinquished ownership, physical control, or even complete and absolute operational control over their transmission assets to MISO. LG&E and KU still own their respective transmission assets: indeed, Article II.1.E of the MISO Agreement expressly states that legal and equitable title remains with LG&E and KU:

> Legal and equitable title to the respective properties comprising the Transmission System . . . shall remain with each respective Owner (unless the Owner transfers title to another entity), and is not changed by this Agreement. The respective owners shall retain all rights incident to such legal and equitable title, including, but not limited to, the right, subject to applicable federal or state regulatory approvals, to build, acquire, sell, dispose of, use as security, convey any part of their property, or use such property for purposes other than providing transmission services . . . .

LG&E and KU have transferred only that level of operational control necessary to allow MISO to perform its functions as transmission coordination and reliability/security coordinator. Under the coordination function, MISO coordinates and evaluates the transmission capacity; LG&E and KU continue to have primary control capability to open and close transmission circuits, perform maintenance on their combined transmission systems and re-dispatch generation. In fact, it is precisely this lack of full control that MISO is now challenging in the wake of the Northeast blackout on August 14, 2003.

Importantly, prior to the formation of MISO, LG&E and KU conveyed to the regional coordinator for the North American Reliability Council ("NERC") in this region of the country (American Electric Power Company) a comparable level of operational control over their respective transmission systems. The former regional NERC coordinator has the right under FERC filed tariffs to curtail transactions, including native load. No KPSC authorization was requested or required in that instance to transfer such control.

Just as the D.C. Circuit in *Atlantic City* (discussed above) determined that the transfer of operational control of FERC-jurisdictional assets does not constitute a "disposition" of facilities sufficient to require FERC approval of such transfer under FPA Section 203, the same limited transfer of control likewise should not trigger the KPSC's jurisdiction: because neither physical control nor the complete and unqualified right of operational control of any assets was transferred, the requirements of Section 278.020(4) were not triggered.

## IV. RESOURCE ADEQUACY AND DEMAND SIDE MANAGEMENT

**Q: The July 17 Order asked LG&E and KU to address the appropriateness of, and jurisdictional basis for, shifting these matters from Kentucky to multi-state, regional organizations. Please describe LG&E's and KU's views on resource adequacy and demand side management.**

A: LG&E and KU believe that any proposal to transfer control of resource adequacy and demand side management functions from the state to a regional advisory group or an RTO must be critically reviewed. As the Companies stated in their January 10, 2003 comments on the FERC's SMD Notice of Proposed Rulemaking ("NOPR"), through existing resource planning processes, load serving entities are committed to establishing the optimal (least cost) mix of generation, transmission and demand-side measures required to meet native load demands: "these plans, including any facility siting and construction, are reviewed and scrutinized by governing state regulatory authorities. The proposed rules could well undermine this planning process to the detriment of native load." The Companies believe that state authority in these areas is not preempted by the FPA.

**Q: What is the legal basis for LG&E's and KU's position that resource adequacy and demand side management decisions are not preempted by federal law?**

A: FPA Section 201(a) limits the FERC's role in the regulation of electricity to "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce," and FPA Section 201(b) (1) specifically enumerates the areas where no federal jurisdiction lies, including "facilities used for the generation of electric energy . . . ." Both FERC and the states have traditionally read these provisions to leave issues related to resource adequacy and demand side management to the states.

**Q: Has FERC said or done anything recently that calls into question state authority over resource adequacy and demand side management programs?**

A: It can be reasonably argued that FERC muddied the waters on these issues in its SMD NOPR. Therein, FERC proposed that the "now-defunct" Independent Transmission Provider (ITP) be required to forecast future demand for its area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee, and assign each load-serving entity in its area a share of the needed future resources based on a ratio of its load to the regional load. Although the FERC stated in the SMD NOPR that its resource adequacy program was designed to complement, not replace, existing state resource adequacy programs, it is easy to see why states might conclude otherwise. Several parties who submitted comments on the SMD NOPR expressed concern that the FERC was overreaching on the issues of resource adequacy and demand side management.

**Q: How has FERC responded to state concerns about jurisdictional issues associated with resource adequacy and demand side management?**

A: In response to the concerns that it was infringing on state jurisdiction in the SMD NOPR, FERC addressed the issue again in its SMD "White Paper" (which was FERC's attempt to clarify certain provisions in the SMD NOPR). In the White Paper, FERC changed the tone, if not the substance, of its pronouncements on resource adequacy, clarifying that nothing in the SMD Final Rule will change state authority over resource adequacy. FERC stated that it will not require a minimum level of resource adequacy, and clarified that an RTO or ISO may implement a resource adequacy program only where a state (or states) asks it to do so, or where a state does not act.

Under FERC's new resource adequacy model, as articulated in the White Paper, the approach to and level of resource adequacy will be decided by the states in the region drawing from a mix of generation, transmission, energy efficiency, and demand response. State regional committees will ensure a consistent approach throughout the region. States may choose to ensure resource adequacy through state-imposed requirements on utilities serving load within the region, or may choose to have RTOs or ISOs operate capacity markets. The choice of which approach to take is left to the states in the region.

**Q: How has MISO addressed resource adequacy and demand side management?**

A: On July 25, 2003, MISO filed its Open Access Transmission and Energy Markets Tariff ("Energy Markets Tariff"). The tariff is divided into "modules" that divide the tariff into separate sections based on subject matter and applicability. Module E in the tariff is reserved as a placeholder for Resource Adequacy.

Module E is being developed by MISO in response to an earlier FERC directive requiring MISO to file information on how resource adequacy will be achieved and a date by which a program will be adopted. To meet this requirement, MISO has been holding stakeholder meetings in the Supply Adequacy Work Group ("SAWG") to discuss the issue. According to MISO, the SAWG has just begun to address key policy issues that need to be resolved in order to develop a resource adequacy plan. In addition, a group of Midwestern state public utility regulatory commissions, including, I believe, the KPSC, has formed the Organization of MISO States, Inc. ("OMS"). One of the OMS committees will deal specifically with resource adequacy. As a result of the combined work of SAWG and OMS, MISO expects to move forward on its resource adequacy program in the first quarter of 2004, develop tariff provisions for Module E during the second quarter of 2004, and file Module E in May 2004 with a requested effective date of October 1, 2004.

Q: **How do LG&E and KU anticipate the MISO resource adequacy process will unfold?**

A: In the areas of resource adequacy and demand side programs the MISO must recognize the authority of the states on these issues. The deliberative process for developing Module E of the MISO tariff will allow all interested parties to participate. The KPSC may present its position through participation in the OMS. However, the Companies are concerned that a resource adequacy and demand side programs proposed by a state advisory panel made up of representatives with potentially diverse position may establish policies that are detrimental to native load. Only through existing state controlled processes can the native load customers be guaranteed that policies are directed for their interest and not a result of a compromise of a group of multi-state representatives where the KPSC constitutes one vote. A dissenting voter under the MISO regime has no other recourse. That is not acceptable to LG&E and KU.

LG&E and KU believe that the MISO resource adequacy process must be viewed with caution before it is allowed to go forward. If evidence emerges that Kentucky's resource adequacy and demand side program requirements are not being fairly considered in the process, the KPSC and the Companies must take all necessary steps to ensure that its ratepayers are not put at risk in the name of regional needs.

**Q: Does this conclude your testimony?**

A: Yes.

## VERIFICATION

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

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

**MICHAEL S. BEER**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of September 2003.

(SEAL)
Notary Public

My Commission Expires:

**Notary Public, State at Large, KY**
**My commission expires June 3, 2006**

# APPENDIX

## MICHAEL S. BEER

**LEGAL EXPERIENCE:**

**LG&E ENERGY CORP.**, Louisville, Kentucky
Vice President, Rates and Regulatory Affairs, February 2001 – Present.
Senior Counsel Specialist-Regulatory, February 2000 – February 2001.
Senior Corporate Attorney, February 1998 – February 2000.

**ILLINOIS POWER COMPANY**, Decatur, Illinois
Director, Federal Regulatory Affairs, February 1997 - January 1998.
Senior Attorney, August 1995 - February 1997.
Attorney, January 1992 - August 1995.

**SOYLAND POWER COOPERATIVE, INC.**, Decatur, Illinois
Attorney, July 1988 - December 1991.
Contract Buyer, March 1982 - July 1984.

**SAMUELS, MILLER, SCHROEDER, JACKSON & SLY**, Decatur, Illinois
Associate, August 1987 - July 1988.

**BEERMAN, SWERDLOVE, WOLOSHIN, BAREZKY & BERKSON**, Chicago, Illinois
Law Clerk/Summer Associate, June 1985 - June 1987.
Offer of permanent employment extended.

**FACULTY POSITIONS:**

**MILLIKIN UNIVERSITY**, Decatur, Illinois
Adjunct Associate Professor of Business Law, January 1996 - December 1998.
Adjunct Assistant Professor of Business Law, August 1988 - December 1995

**EDUCATION:**

**THE JOHN MARSHALL LAW SCHOOL**, Chicago, Illinois
Juris Doctor, with Distinction - June 1987
Admitted to Illinois Bar, 1987

**ILLINOIS WESLEYAN UNIVERSITY**, Bloomington, Illinois
B.A., Business Administration - May 1980

**CARLETON COLLEGE**, Northfield, Minnesota
Attended 1976-77 academic year

**Mathew J. Morey**
**Testimony**

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

**In the matter of:**

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|---|---|---|
| **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** |

**DIRECT TESTIMONY OF**
**MATHEW J. MOREY**
**ON BEHALF OF LOUISVILLE GAS AND ELECTRIC COMPANY**
**AND KENTUCKY UTILITIES COMPANY**

**Filed: September 22, 2003**

***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, VA. Laurits R. Christensen Associates, Inc.'s principal business address is 4610 University Avenue, Madison, WI.

**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 from 1996 to 2000. 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 this year, I was a Principal of Envision Consulting, which I founded in 2000, providing clients in the electricity and natural gas industries with practical research and analysis of and expert witness testimony on economic, financial and statistical issues. Much of the work I performed for clients of Envision Consulting focused on wholesale market design and institutional issues related to the operation and pricing of transmission service. A complete list of my work can be found in the Appendix, attached hereto.

**Q. Have you previously testified before regulatory utility commissions?**

A. Yes, 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 and regulatory policy regarding the design of distribution standby and transmission rates. A complete list of my appearances is contained in my curriculum vita found in the Appendix attached hereto.

**Q. Have you published scholarly work and work in the area of public utility regulation?**

A. Yes, in addition to my scholarly work that appears in the *Journal of Econometrics*, the *American Economic Review* and the *Proceedings of Journal of the American Statistical Association* I have also written papers that have appeared in *Electric Perspectives* and *Public Utilities Fortnightly* and most recently in *The Electricity Journal.*

**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-1 was partly prepared by me and partly prepared under my direct supervision.

***Purpose of Testimony***

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to summarize the analysis conducted by Christensen

Associates of the costs and benefits of Louisville Gas and Electric Company and Kentucky Utilities Company (hereinafter collectively referred to as "LGE/KU") remaining as a member of the Midwest Independent Transmission System Operator ("MISO"), compared with three alternatives. These alternative are: (1) operating as a standalone transmission system (the "Standalone System"), (2) joining an alternative RTO ("SeTrans RTO"), and (3) forming a statewide Independent System Operator ("KY-ISO"). The object of the study is to provide LGE/KU and the Kentucky Public Service Commission ("KPSC" or "Commission") with an unbiased qualitative and quantitative assessment of the costs and benefits to LGE/KU and its native load customers of each of the three alternatives relative to a baseline case of remaining a member of MISO. The full details of the analysis conducted by Christensen Associates can be found in the report entitled "A Cost Benefit Analysis of RTO Options for LGE Energy Corporation" (hereinafter referred to as "Report"), attached hereto as Exhibit MJM-1.

**Q. What issues do you address in your testimony?**

A. My testimony summarizes the results of the cost-benefit study conducted by Christensen Associates. Our study addressed the question of whether the benefits of continued membership in the Midwest Independent Transmission System Operator ("MISO") outweigh the costs for LGE/KU. Because the benefits of membership in transmission organizations, especially organizations in the nascent stages of development, are extremely difficult to quantify, comparisons were made on the basis of estimates of the costs of staying in MISO relative to estimates of the costs of pursuing any one of the three alternative options.

**Q. What questions were you attempting to answer by conducting the cost-benefit study?**

A. Specifically, we attempted to determine if any of the three alternative RTO arrangements might provide greater benefits than the MISO option at the same cost or provides an equivalent set of benefits to LGE/KU and its native load customers at a lower cost.

**Q. What approach did you take with regard to answering this question?**

A. Quantifying the short-term costs and benefits of RTOs and the attendant reformation of wholesale market designs is difficult. Quantifying the longer-term costs and benefits is even more difficult. Therefore, to the extent that we could quantify the costs over the study period (i.e., the period 2004-2010), the analysis compared the costs for LGE/KU to obtain, within the context of each alternative option, a level of services and system reliability that would be comparable to what LGE/KU would receive as member of MISO. For the SeTrans RTO alternative, quantification was difficult because the RTO is in the very early stages of development, no open access tariff has been filed, and the market design is still at a very high level. For the Kentucky ISO alternative, the notion of a statewide ISO is only an idea at this point, and that makes quantification extremely difficult. Consequently, for the most part, we made comparisons of the SeTrans RTO and Kentucky ISO alternatives to the MISO membership option on a qualitative basis.

**Q. Were you able to quantify costs and benefits associated with the standalone system alternative?**

A. Yes. We were able to quantify the incremental savings and incremental costs associated with LGE/KU moving from being a MISO member to the standalone system alternative. Thus, for this particular alternative, we were best able to answer the question: is there an alternative whose incremental costs to implement are less than the incremental costs of the option to remain a member of MISO?

**Q. In preparing the Report, did you consider legal and regulatory policy issues?**

A. In conducting this investigation, we focused on economic issues, leaving the legal and regulatory feasibility of these options to the appropriate experts.

**Q. In preparing the Report, did you address, or will your testimony address, the questions of the jurisdictional basis for and the appropriateness of LGE/KU moving to a world involving regional resource planning and demand resource programs in relation to resource adequacy and demand side management as traditional functions of state regulation in Kentucky?**

A. No. These issues are addressed by other witnesses for LGE/KU.

***<u>Description of the Four Options</u>***

**Q. What institutional options were analyzed?**

A. At the request of LGE/KU, Christensen Associates considered four institutional arrangements with respect to ownership and control of its transmission facilities and varying degrees of participation in regional wholesale markets. The institutional arrangements considered in the Report are (1) remain a member of MISO, (2) leave MISO and operate as a Standalone System, (3) join SeTrans RTO, and (4) join a KY-ISO. The base case scenario has LGE/KU continue to be a MISO member. All other options are considered relative to this option.

**Q. What is the MISO membership option?**

A. Under this scenario, MISO is assumed to take a growing share of planning and operational responsibilities from LGE/KU; and LGE/KU will pay a share of MISO's implementation and administration costs.

**Q. What are the elements of the Standalone System Alternative to remaining a member of MISO?**

A. To become a standalone system, LGE/KU must withdraw from MISO. It would then operate essentially as it did prior to joining MISO and to turning functional control of its transmission facilities over to MISO. Under this alternative, LGE/KU would continue to be the system operator (i.e., control area operator); it would continue to be interconnected as it always has been. Furthermore, it would provide open access transmission service under an Order No. 888 tariff approved by FERC and take responsibility for all of the planning and operational functions that would be necessary to satisfy reliability and security standards imposed by the state, NERC, ECAR or the FERC. In addition, LGE/KU would expect to be answerable to some NERC reliability authority (e.g., MISO, TVA or ECAR).

**Q. What did you assume in the SeTrans RTO alternative to remaining a MISO member?**

A. Under the SeTrans RTO alternative, LGE/KU would withdraw from MISO and join another RTO such as SeTrans. Similar to the option of remaining a member of MISO, we assumed that SeTrans would take a growing share of planning and operational responsibilities from LGE/KU and LGE/KU would pay a share of SeTrans' implementation and administration costs. The SeTrans RTO operations and markets are expected to consist of components very similar to those planned for the

MISO Day 2 market. This scenario is slightly more involved relative to MISO since LGE/KU can join SeTrans as either a participating transmission owner or a non-participating owner that has turned over functional control of transmission facilities to SeTrans. In addition, the scenario is complicated by the fact that the Day 2 market in SeTrans at this point consists of a proposed high-level design. No detailed rules have been worked out. Thus, there is some considerable uncertainty about the effects of a Day 2 market implementation on LGE/KU should it choose to participate in the SeTrans RTO.

**Q. What happens if LGE/KU were to pursue the Kentucky ISO alternative to remaining as a member of MISO?**

A. In the third alternative, LGE/KU would join a KY-ISO that is subject to FERC jurisdiction and designed to satisfy the requirements of FERC Order Nos. 888 and 889 and Order No. 2000. One version of this alternative would require developing a tight power pool within the state from scratch. Thus, many of the functions performed by LGE/KU and MISO and services provided by MISO to its members would be performed and provided by the KY-ISO, presumably in compliance with FERC Order Nos. 888, 889 and Order No. 2000. In addition, we assumed that the KY-ISO would be responsibility for all of the planning and operational functions that would be necessary to satisfy reliability and security standards imposed by the state, NERC, ECAR or the FERC.

***Factors Considered in the Cost Benefit Study***

**Q. What factors did you consider as relevant to a determination of the costs and benefits of the three alternatives relative to LGE/KU's continuation as a**

**member of MISO?**

A. The companies' decision to remain a member of MISO, operate as a stand-alone system, join an alternative RTO, or participate in a Kentucky state ISO is one that may have wide-ranging consequences for the companies, their native load customers and their shareholders. As I have indicated, not all of the factors that must be considered in making a choice of this kind can be easily quantified, and even those that can be quantified are typically subject to great uncertainty, especially when the analysis seeks to value long-term benefits and costs.

The analysis identified and, to the extent possible, quantified what Christensen Associates believed were the principal drivers of the differences in the cost and benefits associated with staying in MISO relative to the three alternatives. These drivers include the following factors, which we, at the outset, expected to significantly differ qualitatively and quantitatively among alternatives:

- revenues/profits from off system sales;
- opportunities to purchase economy power from a broader market;
- the quantity of transmission capacity investments;
- LGE/KU's share of the costs of transmission capacity investments;
- access to transmission service;
- allocation of transmission rights;
- transmission revenues;
- payments/costs of transmission service;
- reliability and planning benefits;
- system operations costs;
- LGE/KU's share of market implementation and administration costs;
- resource adequacy obligation;
- Order No. 2000 and SMD implementation obligations;

- obligation to pay MISO exit fees; and
- legal, regulatory and transaction costs.

Many of these factors, as I said before, could not be easily quantified. Several factors were determined to vary only sligtly or not at all, regardless of the alternative considered.

***Summary of the Report's Findings***

***Alternative 1: Standalone Transmission System Option***

**Q. Please summarize the results of the cost-benefit analysis for the Standalone System Option described above.**

A. Aside from the uncertainties attendant to a decision to withdraw from MISO, especially with respect to the reactions of the FERC and the actions of Congress on pending federal energy legislation, which have not been factored into this analysis, it appears that the greatest net benefits to LGE/KU and its native load customers would occur under the option of operating as a stand-alone transmission system. This option is attractive relative to remaining in MISO primarily because LGE/KU's system operations and other costs for a running a standalone system are significantly lower than the costs of operating the LGE/KU system within the MISO market and paying MISO for its system operation and market administration services. Moreover, the reduction in system operation costs that attend LGE/KU reverting to a stand-alone system will be more than sufficient, over the study period (i.e., 2004 to 2010), to offset the exit fee that LGE/KU will have to pay to MISO for such reversion in 2004.

**Q. What are the principal reasons for the costs differences between the standalone alternative and the MISO membership option?**

A. The costs of a stand-alone system option are lower than those of MISO membership option for three reasons. First, costs for LGE/KU to operate a standalone system that replicates the functions necessary for it to meet Orders No. 888 and No. 889 and Order No. 2000 obligations and maintain a reliable system to serve native load customers are lower because LGE/KU does not need to replicate the functionality that MISO is attempting to achieve in its Day 2 market or in coordinating that market with adjacent markets, such as PJM. In addition, the functions MISO performs will partly duplicate those that LGE/KU will continue to have to perform as a MISO member. LGE/KU, in an effort to satisfy its obligations under Order 2000 (and Orders No. 888 and 889) need not incur the costs associated with implementation and administration of energy markets, ancillary service markets, financial transmission rights markets to meet its obligation to serve native load customers.

Second, MISO's cost allocation (particularly through its Schedule 10) assigns to LGE/KU costs that are not caused by LGE/KU's participation in MISO, at least in an incremental sense. By withdrawing to run a standalone system, LGE/KU will avoid paying implementation and administration charges that it originally believed it would not incur until after a transition period (i.e., through 2008). Judging by the histories of all existing RTOs and ISOs operating in other regional markets, MISO's costs of achieving full operational status are expected to rise over the next several years. Thus, the savings that LGE/KU may enjoy from operating as a standalone system in terms of implementation and administration charges may rise in the near future.

Third, by operating as a standalone system, LGE/KU will avoid expending money on its staff's participation in numerous MISO proceedings that are dealing with the creation of the MISO market. Because MISO, like California, is creating its market from scratch, it is reasonable to expect these proceedings to continue for at least several more years. The participation is expected to include legal and regulatory costs, this proceeding being one example.

**Q. Are there any benefits besides lower costs associated with the standalone system alternative?**

A. Yes. Being a standalone utility will allow LGE/KU to enjoy most of the trading opportunities that it would enjoy as a MISO member and to avoid some costly obligations to MISO, all for the loss of few membership advantages. Regardless of membership, LGE/KU will be able to trade with MISO participants at the nodal price at the boundary of LGE/KU and MISO, will be able to purchase transmission service from MISO if it chooses to do so, will be able to purchase ancillary services from MISO should MISO choose to offer such services, and will be able ultimately to purchase financial transmission rights ("FTRs") in a secondary market as a hedge against the cost of congestion if it chooses to trade beyond the LGE/KU-MISO border bus with MISO members.

In addition, by operating a stand-alone system, LGE/KU would be better able to control the costs and the risks that it faces from transmission congestion within its own transmission system as it delivers power from its generation to its loads, and would be better able to avoid curtailment within its system. These benefits are not easily quantified over the study period, but they are important to consider in a decision about whether to remain a member of MISO or to consider an alternative option.

**Q. What are the results of the comparison of the costs of the MISO membership option and the Standalone System alternative?**

A. Table 1 summarizes a breakeven analysis of the differences between the MISO RTO option and the alternative of operating as a standalone system. The analysis shows that the preferred option is for LGE/KU to operate as a standalone system. The incremental costs for LGE/KU to operate as a standalone system and self-provide the services that MISO currently provides or would be expected to provide to LGE/KU over the period 2005-2010 are less than the costs of continuing as a MISO member.

Table 1 is based upon the Base Budget Scenario which assumes that the MISO capital and operating budget follows a path implied by MISO's own forecasts of its Schedules 10, 16, and 17 charges under the MISO Open Access Transmission Tariff ("OATT"), by which it recovers the costs of startup, capital investment, operations and market administration. The Base Budget Scenario represents a lower bound estimate of the savings attendant to LGE/KU running a standalone system.

Withdrawal from MISO would enable LGE/KU to avoid at least \$8.45 million per year in implementation and administration charges. When all incremental savings and incremental costs that we could quantify are considered (excluding the exit fee of \$23 million paid at the end of 2004), LGE/KU may expect to net an annual savings of approximately \$11.13 million (in nominal dollars). The savings in nominal dollars represents about 16% of LGE/KU's annual transmission revenue requirement of $70 million.

The net cumulative savings in nominal dollars by 2010 (including the $23 million exit fee) is estimated to be $43.80 million (an average of $7.3 million per year over 2005-2010). The net cumulative savings has a net present value of $30.23 million (an average of $5.04 million per year over 2005-2010).[1] Thus, even if LGE/KU must pay an estimated $23 million to exit MISO in 2004, it recovers that fee through net savings by early 2007.

**Table 1 Breakeven Analysis: MISO vs. Standalone System Option (LGE/KU Exits 12/31/2004)**

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|
| Savings ($Millions) | | | | | | | |
| System Operations and Transmission Related Costs | | 9.30 | 8.80 | 7.70 | 7.70 | 7.70 | 7.70 |
| Implementation & Administration Costs | | 8.76 | 9.01 | 9.22 | 8.94 | 7.88 | 8.03 |
| Legal, Regulatory & Transaction Costs (net) | | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |
| Total Savings | | 19.31 | 19.06 | 18.16 | 17.88 | 16.82 | 16.98 |
| Additional Costs ($Millions) | | | | | | | |
| MISO Exit Fee | -23.00 | | | | | | |
| System Operations Costs | | -1.02 | -1.02 | -1.02 | -1.02 | -1.02 | -1.02 |
| Lost Revenues | | -6.50 | -6.50 | -5.00 | -5.00 | -5.00 | -5.00 |
| Implementation & Administration Costs for Off-System Trades | | -0.39 | -0.40 | -0.40 | -0.39 | -0.34 | -0.35 |
| Total Additional Costs | -23.00 | -7.91 | -7.92 | -6.42 | -6.41 | -6.36 | -6.37 |
| Net Savings (Costs) Nominal $ (Total Savings minus Total Additional Costs) | -23.00 | 11.39 | 11.13 | 11.74 | 11.47 | 10.46 | 10.61 |
| Net Cumulative Savings (Costs) Nominal $ | -23.00 | -11.61 | -0.48 | 11.26 | 22.73 | 33.19 | 43.80 |
| Net Cumulative Savings (Costs) NPV(7% discount rate) | -23.00 | -12.35 | -2.63 | 6.95 | 15.70 | 23.16 | 30.23 |

One uncertainty is whether the efficiencies of commitment, dispatch, and generation and transmission investments will vary significantly among the RTO options. In theory, a single large control area should be able to manage these functions more

[1] Discounted at the rate of 7% per annum.

efficiently than many small control areas, and with a higher level of reliability; and, again in theory, an appropriate cost allocation can provide all market participants with a share of the resulting efficiency benefits. In practice, however, it is not clear that these efficiencies will outweigh the extra administrative costs of operating an RTO. Because MISO will continue to have 23 control areas for the foreseeable future, the efficiency case for MISO is arguably doubtful. Even if MISO does offer net efficiency gains, some portion of these gains can be captured by utilities at MISO's borders without these utilities directly participating in MISO.

***Alternative 2: Joining the SeTrans RTO***

**Q. What are the results of your analysis of the second alternative, joining the SeTrans RTO, compared to LGE/KU continuing as a MISO member?**

A. For LGE/KU and its native load customers to benefit over the study period (i.e., 2004 to 2010) from a switch to SeTrans RTO participation, at least one of two conditions would need to be satisfied. First, the cost of SeTrans membership over the period 2004-2010 would need to be lower than the cost of MISO membership by at least the amount of the MISO exit fee (approximately $23 million over six years, or roughly $3.8 million per year before discounting). I am not aware of any evidence that indicates that there will be any difference at all between the costs of membership in these two organizations.

Second, the LGE/KU transmission system would need better physical interconnection with the SeTrans transmission system than with the MISO transmission system, thus permitting superior operational economies that could confer benefits on LGE/KU and its native load customers. On the contrary, however, LGE/KU is closely connected to MISO and does not possess any direct electrical interconnection to SeTrans. Consequently, there is little reason to believe that SeTrans RTO membership will be more beneficial to LGE/KU than would MISO membership; while there are strong reasons to believe that MISO membership will be more beneficial or would provide at least as great a benefit at lower cost.

***Alternative 3: Participating Within a Kentucky ISO***

**Q. What are the results of your analysis of the third alternative, joining a Kentucky state ISO, compared to LGE/KU continuing as a MISO member?**

A. LGE/KU's membership in a Kentucky state ISO would appear to be at least as problematic as membership in the SeTrans RTO, and for essentially the same reasons.

First, a Kentucky state ISO is likely to have costs that are higher (on a per MWh basis) than those of MISO – and perhaps higher than other existing and planned ISOs and RTOs as well. There are several reasons why I believe that the costs of a Kentucky ISO would be higher than the costs of continuing as a member of MISO. Like MISO and the SeTrans RTO, a Kentucky ISO would have to be built from scratch. It is possible that it could be created more inexpensively by designing it to include a minimal set of functions, so that, for example, it did not incorporate the day-ahead market or locational pricing that are characteristics of FERC's Standard Market Design ("SMD") and of other existing RTOs and ISOs. But because day-ahead markets facilitate unit commitment and locational prices help manage transmission congestion, building a "minimal" ISO will come at the cost of reduced operating efficiencies and may ultimately give way to a more complete and more expensive ISO design, if the experiences of PJM, New England, and California can be used as a guide.

**Q. What can be said about the per unit costs of setting up a Kentucky ISO?**

A. The real disadvantage of a Kentucky ISO relative to MISO, SeTrans, and all of the RTOs is that the Kentucky market is significantly smaller than those of the other RTOs. As indicated in Table 2, the entire Kentucky market had a combined (non-coincident) summer peak demand roughly equal to 12,400 MW in 2002.[2] The other RTOs and ISOs have summer peaks that are two to ten times larger than that of a prospective Kentucky ISO, with MISO being the largest of them all. The energy statistics tell a similar story. Given that the startup and administrative costs of a Kentucky ISO would be nearly as high as the costs incurred by other ISOs and RTOs of much larger size (perhaps in the neighborhood of $80 to $100 million) and that the costs of a Kentucky ISO would be spread over a smaller volume of business, it is very likely that a Kentucky ISO would have significantly higher start-up and administrative costs per unit of business than do the other ISOs.

**Q. Are there any other issues that make formation of a Kentucky ISO problematic?**

A. Yes, Kentucky does not have a transmission system that is well integrated internally. For geographical and historical reasons, northern Kentucky's power system is well integrated with those of Indiana and Ohio; southern Kentucky's power system is integrated with that of Tennessee; and eastern Kentucky's power system is integrated with those of West Virginia and Virginia. The transmission links between northern

2 Not weather normalized.

Kentucky, southern Kentucky, and eastern Kentucky are not as strong as they may need to be to enable a Kentucky ISO to operate an efficient dispatch. These weaknesses have been acknowledged by LGE/KU in its most recent integrated resource plan.[3] In terms of the physics of the transmission system, it makes little sense to draw an ISO boundary at the state line. For the Kentucky grid to be well interconnected would require substantial investments in infrastructure upgrades and expansions that may not necessarily be efficient. Furthermore, the costs of grid investment will have to be recovered from a relatively small volume of energy sales and peak load.

**Table 2 Comparative Statistics for Kentucky and RTOs/ISOs in 2002**

| RTO/ISO | Generation Capacity (MW) | Summer Peak Load (MW) |
|---|---|---|
| MISO | 155,000 | 130,000 |
| PJM | 76,000 | 63,762 |
| Texas ERCOT | 75,000 | 57,606 |
| CA ISO | 54,000 | 43,000 |
| New York ISO | 37,100 | 31,430 |
| ISO New England | 31,000 | 25,400 |
| Kentucky ISO | 13,000 | 12,400 |

Finally, there will be several regulatory hurdles that a Kentucky ISO would have to overcome that would add to the costs of creating such an organization. Any attempt to reduce costs by eliminating any function or characteristic of an ISO or RTO as

3 The topology of the LGE/KU system and interconnections with adjacent control areas within Kentucky is such that, according to the 2002 IRP: "A limitation to transfer capability with other companies sometimes occurs when large north-south transfers are present. These north-south transfers have a significant impact on flows on the Companies' system. The ability to export KU and LG&E generation to other control areas is limited under these conditions. Additionally, the ability to dispatch generation economically within the Companies' control area may be limited under these conditions."

defined in Order No. 2000 must be accompanied by a convincing cost-benefit analysis.[4] Finally, FERC has indicated that a final rule on SMD or a wholesale market platform will require all ISOs and RTOs to actively pursue interregional coordination, including the elimination of the payment of multiple access fees for transactions that cross ISO and RTO borders. Consequently, any chance of spreading the fixed or administrative costs of the state ISO across a base that included through and out transmission transactions would likely be eliminated.[5] Also, because a Kentucky ISO would not likely satisfy the Order No. 2000 scope and configuration characteristics of an RTO, it may still be required to participate in an RTO (MISO most likely), insofar as a final rule would make an RTO the sole provider of transmission service and sole administrator of the open access tariff, including the requirement that an RTO have the sole authority for the evaluation and approval of all requests for transmission service including requests for new interconnections. As a member of MISO, the state ISO would likely pass on the costs of membership to the participating state transmission owners. Thus, LGE/KU may not be able to avoid completely the costs associated with its MISO membership by withdrawing from MISO and creating a statewide ISO.

***<u>Potential Impact on Native Load Customers</u>***

**Q. In light of the fact that the MISO membership option is more costly than the standalone system option, what would be the impact on native load**

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4 White Paper, "Wholesale Power Market Platform," April 28, 2003, Docket No. RM01-12-000, at 2.

5 This assumption is also supported by the FERC's recent order in the EL02-111 case in which it eliminated through and out rates between MISO and PJM effective November 1, 2003.

**customers of an LGE/KU decision to remain a member of MISO?**

A. Considering the breakeven analysis presented in Table 1 above, the net savings in nominal dollars foregone if LGE/KU chose to remain a member of MISO will average approximately $11.13 million per year over the period 2005 to 2010. The net present value of the net cumulative savings over the period 2005 to 2010 is estimated to be $30.23 million. Under the companies' forecast of energy sales to native load customers[6] over the period 2005 to 2010, which is 212,500 GWh, if LGE/KU remained a member of MISO, the savings that would be foregone in 2004 dollars translates into an average cost of about 0.14 mills per kWh. For the average residential customer (i.e., a household) that consumes 12 thousand kWh per year, the foregone savings from LGE/KU's staying in MISO would be about $1.40 per year.

**Q. Is this fact relevant to the economics of the decision about remaining in MISO or pursuing an alternative arrangement, such as the standalone system option?**

A. No. When expressed in these terms, it could be argued that the impact on the typical residential customer is so slight that it would likely not be noticed, but this would be missing the point of the breakeven analysis and the comparisons we have drawn between the costs of the MISO option and the incremental costs of the standalone system option. The estimated annual savings associated with a standalone system option for LGE/KU is $11.13 million. The total savings over the period 2005-2010 will be $53.23 million in net present value terms. The Companies would recover the $23 million exit fee by early 2007, in less than three years from the time they exit,

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[6] Refer to Table 2.1 in the Report.

assuming they exit at the end of 2004. By 2010, the Companies will have saved an estimated $30.23 million in net present value terms beyond payment of the exit fee. The decision to pay $23 million to withdraw from MISO to save $30.23 million more than the exit fee would appear to be an economically wise decision, in light of the difficulty in determining a correspondingly larger value that can be assigned to the benefits of continued MISO membership.

***Conclusion***

**Q. What conclusions have you reached about the preferences that should be expressed by LGE/KU for each of the four options considered in the cost-benefit analysis conducted by Christensen Associates?**

A. First, as I indicated, some of the factors that must be considered in choosing among the options can be reasonably quantified (the costs in particular), while others are subject to significant uncertainty. And for all categories of benefits and costs, even those most susceptible to quantification, the uncertainties become larger as one looks to estimate longer-term benefits and costs.

Therefore, considerable uncertainty remains about the short-term and long-term benefits of LGE/KU's three options compared to a continuation of its MISO membership because of the difficulty in quantifying a significant number of the principal factors that drive LGE/KU's relevant administrative, operational and regulatory costs under each option. Consequently, the Report quantified those factors for which we could obtain reliable information and qualitatively analyzed those factors for which we could not. Nonetheless, the preponderance of evidence leads me to conclude that the most favorable option for LGE/KU would be to operate as a standalone transmission system. If on the basis of legal analysis it is concluded that the only way LGE/KU can be in compliance with FERC rules—Orders No. 888., No. 889 and No. 2000, and requirements emerging from a rulemaking on SMD or a wholesale market platform or Congressional legislation—is to be a member of an RTO or ISO, I conclude that the evidence supports a decision to continue as member of MISO. On the basis of the evidence examined, I conclude that neither the SeTrans RTO nor the Kentucky ISO options appear to be viable candidates for choice.

**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 that as a Senior Consultant, Laurits R. Christensen Associates, Inc., he has personal knowledge of the matters set forth in the foregoing testimony, and 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 City and State, this 17 day of September 2003.

(SEAL)

Notary Public

My Commission Expires:

5-31-06

# 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:*

"How Can FERC Find Its Way Out of the SMD Cul-de-Sac? Stimulate the Transmission Sector!" with Christina C. Forbes, forthcoming in *The Electricity Journal*, Volume 16, Number 7, August/September 2003.

"Performance-based Regulation for Independent Transmission Companies: 'Delivering' the Promise of Standard Market Design," *The Electricity Journal*, Volume 16, Number 5, June 2003, pp. 35-51.

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Exhibit MJM-1

# A COST-BENEFIT ANALYSIS OF RTO OPTIONS FOR LGE ENERGY CORPORATION

*prepared for*

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September 22, 2003

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## EXECUTIVE SUMMARY

On July 17, 2003, the Kentucky Public Service Commission ("KPSC") issued an order on its own motion to initiate an investigation regarding the membership of Louisville Gas & Electric ("LG&E") and Kentucky Utilities Company ("KU") in MISO. The Commission stated that "one issue to be reviewed herein is the extent to which LG&E and KU, as providers of bundled retail electricity, utilize and receive benefits from the services provided by MISO, and whether those benefits are commensurate with the costs." The KPSC confronted a similar question in responding to the application of Kentucky Power Company to join PJM Interconnection, L.L.C.

This report addresses the question of whether the benefits of continued membership in the Midwest Independent Transmission System Operator ("MISO") outweigh the costs for LG&E and KU (collectively referred to henceforth as "LGE/KU"). This report considers four options for LGE/KU's RTO participation:

- Remaining a member of MISO;
- Operating as a stand-alone transmission system;
- Joining an alternative RTO (e.g., SeTrans); and
- Participating in the formation a state-wide independent system operator (KY-ISO) for Kentucky.

In conducting this investigation, we consider only economic issues, leaving the legal and regulatory feasibility of these options to the appropriate experts.

While some of the factors that must be considered in choosing among the options can be reasonably quantified, others are subject to significant uncertainty. For all categories of benefits and costs, even those most susceptible to quantification, the uncertainties become larger as one looks to estimate longer-term benefits and costs.

### Operating as a Stand-Alone Transmission System vs. Continued MISO Participation

Aside from the uncertainties attendant to a decision to withdraw from MISO, especially with respect to the reactions of the Federal Energy Regulatory Commission and the actions of Congress on federal energy legislation, it appears to us that the greatest net benefits to LGE/KU and its customers would occur under the option of operating as a stand-alone transmission system. This option is attractive relative to remaining in MISO primarily because LGE/KU's system operation costs for a stand-alone system are significantly lower than the payments to MISO for the latter's system operation services. Moreover, the reduction in system operation costs that attend LGE/KU reverting to a stand-alone system will be more than sufficient, over the period under study (i.e., 2004 to 2010), to offset the exit fee that LGE/KU will have to pay to MISO for such reversion.[1]

We expect that the costs of a stand-alone system are lower than those of MISO membership for three reasons. First, MISO's functions partly duplicate those that LGE/KU will continue to perform as a MISO member. Second, MISO's cost allocation (particularly through its Schedule 10) assigns to LGE/KU costs that are not caused by LGE/KU's participation in MISO, at least in

[1] The net present value of these savings, discounted to 2004 at 7% per annum, exceeds the estimated exit fee.

an incremental sense. Third, LGE/KU's membership in MISO has required and will require that it expend significant sums of money on its staff's participation in numerous MISO proceedings that are dealing with the creation of the MISO market; and because MISO, like California, is creating its market from scratch, it is reasonable to expect these proceedings to continue for at least several more years.

Being a stand-alone utility will allow LGE/KU to enjoy most of the trading opportunities that it would enjoy as a MISO member and to avoid some costly obligations to MISO, all for the loss of few membership advantages. Regardless of membership, LGE/KU will be able to trade with MISO participants at the nodal price at the boundary of LGE/KU and MISO, will be able to purchase transmission service from MISO, will be able to purchase ancillary services from MISO should MISO choose to offer such services, and will be able ultimately to purchase financial transmission rights ("FTRs") in a secondary market as a hedge against the cost of congestion within MISO, if there were ever any need to do so.

By being a stand-alone utility, LGE/KU would be better able to control the costs and the risks that it faces from transmission congestion within its own transmission system as it delivers power from its generation to its loads, and would be better able to avoid curtailment within its system. A disadvantage of giving up MISO membership is that LGE/KU may be more prone to curtailment of its transactions with MISO members.

Tables ES.1 and Figure ES.1 summarize a breakeven analysis of the differences between the MISO RTO base case option and the alternative of operating as a standalone system. The analysis suggests that the preferred option is for LGE/KU to operate as a standalone system. The incremental costs for LGE/KU to operate as a standalone system and self-provide the services that MISO currently provides or would be expected to provide to LGE/KU over the period 2005-2010 are less than the costs of continuing as a member

The MISO Base Budget Scenario assumes that the MISO capital and operating budget follows a path implied by MISO's own forecasts of the Schedules 10, 16, and 17 charges, represents a lower bound estimate of the savings that can be achieved by LGE/KU running a standalone system.

Withdrawal from MISO would enable LGE/KU as standalone system to avoid at least $8.45 million per year in MISO implementation and administration charges. When all savings and additional costs are considered, LGE/KU may expect to net a savings of approximately $11.13 million per year (in nominal dollars) and $8.87 million per year in net present value terms.[2] The savings in nominal dollars represents about 16% of LGE/KU's transmission operating budget of $70 million. Even if LGE/KU must pay $23 million to exit MISO in 2004, it recovers that fee by early 2007. Under an alternative scenario in which MISO's capital and operating budget is assumed to grow at the rate of 10% per year from 2005-2007, LGE/KU would recover the fee in less than 18 months.

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2 This is a net present value in 2004 dollars discounted at 7% per annum.

**Table ES. 1 Breakeven Analysis: MISO vs. Standalone System Option (LGE/KU Exits 12/31/2004)**

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|
| Savings ($Millions) | | | | | | | |
| System Operations Costs | | 9.30 | 8.80 | 7.70 | 7.70 | 7.70 | 7.70 |
| Implementation & Administration Costs | | 8.76 | 9.01 | 9.22 | 8.94 | 7.88 | 8.03 |
| Legal, Regulatory & Transaction Costs (net) | | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |
| Total Savings | | 19.31 | 19.06 | 18.16 | 17.88 | 16.82 | 16.98 |
| Additional Costs ($Millions) | | | | | | | |
| Pay MISO Exit | -23.00 | | | | | | |
| System Operations Costs | | -1.02 | -1.02 | -1.02 | -1.02 | -1.02 | -1.02 |
| Lost Revenues | | -6.50 | -6.50 | -5.00 | -5.00 | -5.00 | -5.00 |
| Implementation & Administration Costs for Off-System Trades | | -0.39 | -0.40 | -0.40 | -0.39 | -0.34 | -0.35 |
| Total Additional Costs | -23.00 | -7.91 | -7.92 | -6.42 | -6.41 | -6.36 | -6.37 |
| Net Savings (Costs) | -23.00 | 11.39 | 11.13 | 11.74 | 11.47 | 10.46 | 10.61 |
| Net Cumulative Savings (Costs) Nominal $ | -23.00 | -11.61 | -0.48 | 11.26 | 22.73 | 33.19 | 43.80 |
| Cumulative Net Savings (Costs) NPV | -23.00 | -12.35 | -2.63 | 6.95 | 15.70 | 23.16 | 30.23 |

An uncertainty is whether the efficiencies of commitment, dispatch, and generation and transmission investments will vary significantly among scenarios. In theory, a single large control area should be able to manage these functions more efficiently than many small control areas, and with a higher level of reliability; and, again in theory, an appropriate cost allocation can provide all market participants with a share of the resulting efficiency benefits. In practice, however, it is not clear that these efficiencies outweigh the extra administrative costs of operating an RTO. Because MISO will continue to have 23 control areas for the foreseeable future, the efficiency case for MISO is arguably doubtful. Even if MISO does offer net efficiency gains, some portion of these gains can be captured by utilities at MISO's borders without these utilities directly participating in MISO.

### Joining the SeTrans RTO vs. Continued MISO Participation

For LGE/KU and its native load customers to benefit over the study period (i.e., 2004 to 2010) from a switch to SeTrans RTO participation, at least one of two conditions would need to be satisfied. First, the cost of SeTrans membership over the period 2004-2010 would need to be lower than the cost of MISO membership by at least the amount of the MISO exit fee (approximately $23 million over 6 years, or roughly $3.8 million per year). We are not aware of any evidence that indicates that there will be any difference at all between the costs of membership in these two organizations.

Second, the LGE/KU transmission system would need better physical interconnection with the SeTrans transmission system than with the MISO transmission system, thus permitting superior operational economies that could confer benefits on LGE/KU and its native load customers. On the contrary, however, LGE/KU is closely interconnected with MISO and does not have any direct electrical interconnection to SeTrans.

Consequently, there is little reason to believe that SeTrans membership will be more beneficial to LGE/KU than would MISO membership, while there are good reasons to believe that MISO membership will be more beneficial.

**Participating in a Kentucky State ISO vs. Continued MISO Participation**

LGE/KU's membership in a Kentucky state ISO would appear to be at least as problematic as membership in the SeTrans RTO, and for essentially the same reasons.

First, a Kentucky state ISO is likely to have costs that are higher (on a per MWh basis) than those of MISO – and perhaps higher than other existing and planned ISOs and RTOs as well. Like MISO and SeTrans, a Kentucky state ISO would have to be built from scratch. It is possible that it could be created more inexpensively by designing it to include a minimal set of functions, so that (for example) it did not incorporate the day-ahead market or locational pricing that are characteristics of FERC's Standard Market Design ("SMD") and of other RTOs and ISOs. But because day-ahead markets facilitate unit commitment and locational prices help manage transmission congestion, building a "minimal" ISO will come at the cost of reduced operating efficiencies and may ultimately give way to a more complete and more expensive ISO design, if the experiences of PJM, New England, and California can be used as a guide.

The real disadvantage of a Kentucky ISO relative to MISO, SeTrans, and all of the RTOs is that the Kentucky market is significantly smaller than those of the other RTOs. As indicated in Table ES2, the Kentucky market has a combined (non-coincident) summer peak demand roughly equal to 12,400 MW in 2002.[3] The other RTOs and ISOs have summer peaks that are two to ten times larger than that of a prospective Kentucky ISO, with MISO being the largest of them all. The energy statistics tell a similar story. Because the startup and administrative costs of a Kentucky state ISO would be nearly as high as the costs incurred by other ISOs and RTOs of much larger size while its costs would be spread over a smaller volume of business, it is very likely that a Kentucky ISO would have significantly higher start-up and administrative costs per unit of business than do the other ISOs.

Second, Kentucky does not have a transmission system that is internally well integrated. For geographical and historical reasons, northern Kentucky's power system is well integrated with those of Indiana and Ohio; southern Kentucky's power system is integrated with that of Tennessee; and eastern Kentucky's power system is integrated with those of West Virginia and Virginia. The transmission links between northern Kentucky, southern Kentucky, and eastern Kentucky are relatively weak. These weaknesses have been acknowledged by LGE/KU in its most recent integrated resource plan.[4] In terms of the physics of the transmission system, it

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[3] Not weather normalized.

[4] The topology of the LGE/KU system and interconnections with adjacent control areas within Kentucky is such that, according to the 2002 IRP: "A limitation to transfer capability with other companies sometimes occurs when large north-south transfers are present. These north-south transfers have a significant impact on flows on the Companies' system. The ability to export KU and LG&E generation to other control areas is limited under these conditions. Additionally, the ability to dispatch generation economically within the Companies' control area may be limited under these conditions."

makes little sense to draw an ISO boundary at the state line. For the Kentucky grid to be well interconnected would require substantial investments in infrastructure upgrades and expansions that may not necessarily be efficient. Furthermore, the costs of grid investment will have to be recovered from a relatively small volume of energy sales and peak load.

**Table ES2 Comparative Statistics for Kentucky and RTOs/ISOs in 2002**

| RTO/ISO | Generation Capacity (MW) | Summer Peak Load (MW) | Annual Consumption (GWh) |
|---|---|---|---|
| MISO | 155,000 | 130,000 | 840,000 |
| PJM | 76,000 | 63,762 | 329,000 |
| Texas ERCOT | 75,000 | 57,606 | 240,000 |
| CA ISO | 54,000 | 43,000 | 246,500 |
| New York ISO | 37,100 | 31,430 | 158,744 |
| ISO New England | 31,000 | 25,400 | 128,000 |
| Kentucky ISO | 13,000 | 12,400 | 80,800 |

## Implications from RTO Cost-Benefit Studies

Recent studies of the costs and benefits of RTO formation provide remarkably similar results and suggest generally what might be revealed in a more targeted analysis, albeit from the perspective of an individual utility and its native load customers. The short-term benefit on average has been estimated to be about $0.20/MWh (savings are mostly in production costs) while the short-term incremental cost averages about $0.24/MWh (this stems primarily from startup costs). The long-term benefit has been estimated to fall in the range of $0.35 per MWh to $1.00 per MWh, and the long-term (total) cost averages roughly $0.44/MWh. Therefore, the net benefit long term is between -$0.08 per MWh and $0.56/MWh. Three general conclusions can be reached from these studies. First, in the short-term there is no net benefit to RTO formation, and perhaps to RTO membership. Second, RTOs are expensive to get organized and to run. For example, the current generation and transmission dispatch center costs for the 84 largest jurisdictional utilities is about $400/MW-year, whereas the generation and transmission dispatch center costs for the existing RTOs is about $1,400/MW-year.[5] The savings in production costs are offset by the costs of implementation and administration. Third, the long-term benefits (over 15 to 20 years) could be significant, although the estimates are tenuous. While an analysis of the MISO and SeTrans RTO options may produce similar results, differences may arise when viewed from LGE/KU's perspective. In light of these results, the prospect of creating a Kentucky ISO would be faced with the same or similar short-term and long-term costs without the benefit of a fully integrated regional system that might enable the savings to be achieved in production costs.

## Conclusions

[5] U.S. Department of Energy, "Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design," April 30, 2003.

At the request of LGE/KU, Christensen Associates undertook an investigation of four options for LGE/KU's RTO participation:

- Remaining a member of MISO;
- Operating as a stand-alone transmission system;
- Joining an alternative RTO (e.g., SeTrans); and
- Participating in the formation a state-wide independent system operator for Kentucky.

In conducting this investigation, we have considered only economic issues, leaving the legal and regulatory feasibility of these options to the appropriate experts.

If on the basis of legal analysis it is concluded that the only way LGE/KU can be in compliance with FERC rules—Orders No. 888. No. 889 and No. 2000, and requirements emerging from a rulemaking on SMD or a wholesale market platform—is to be a member of an RTO or ISO, we conclude that the evidence supports a decision to continue as member of MISO. The basic reasons are that MISO's size allows its costs to be spread over a large quantity of transactions, that LGE/KU has strong interconnections with MISO, and that LGE/KU would not be subject to an exit fee. On the basis of the evidence examined, neither the SeTrans RTO nor the Kentucky ISO options appear to be viable candidates for choice.

If law or regulation does not require LGE/KU to be a member of an RTO or ISO, the preponderance of evidence leads us to conclude that the most favorable option for LGE/KU would be to operate as a standalone transmission system. The reason is that the incremental savings from a standalone system exceed the incremental costs to the extent that even if LGE/KU must pay an exit fee to MISO, it will break even within the first two years of operations. Withdrawal from MISO and operating as standalone system enables LGE/KU to achieve a net savings of at least $11.13 million per year in MISO, including nearly $8.45 million per year in MISO implementation and administration charges over the period 2005 to 2010. Furthermore, if LGE/KU operated as a standalone system, it could still obtain for its native load customers many of the benefits that accrue to MISO members because it is a first-tier utility vis-à-vis MISO. The analysis suggests that the functions MISO now performs or will be performing on behalf of LGE/KU the companies can self-supply at lower incremental cost.

We emphasize that we were able to reasonably quantify only some of the factors that must be considered in choosing among the options, and even these are subject to significant uncertainty. For all categories of benefits and costs, including those most susceptible to quantification, the uncertainties become larger as one looks to estimate longer-term benefits and costs.

# COST-BENEFIT ANALYSIS OF RTO OPTIONS FOR LGE ENERGY CORPORATION

## 1. INTRODUCTION

LGE Energy Corporation ("LGE/KU") engaged Laurits R. Christensen Associates, Inc. to conduct a study of the benefits and costs associated with the decision to remain a member of the Midwest Independent Transmission System Operator ("MISO") compared to three alternative institutional options:

- Operating the LGE/KU system as a stand-alone transmission system;
- Joining an alternative RTO ("SeTrans"); and
- Participating in the formation of a state-wide independent system operator ("KY-ISO") for Kentucky.

The object of this study is to provide LGE/KU and the Kentucky Public Service Commission ("KPSC" or "Commission") with an unbiased qualitative and quantitative assessment of the costs and benefits to LGE/KU and its native load customers of each of the three alternatives relative to a baseline case of remaining as a member of MISO.

### 1.1 Regulatory Background

On July 17, 2003, the KPSC issued an order on its own motion to initiate an investigation into the membership of Louisville Gas & Electric ("LG&E") and Kentucky Utilities Company ("KU") in MISO. The Commission stated that "one issue to be reviewed herein is the extent to which LG&E and KU, as providers of bundled retail electricity, utilize and receive benefits from the services provided by MISO, and whether those benefits are commensurate with the costs." The KPSC conducted a similar investigation in response to the application of Kentucky Power Company ("KP") to join PJM Interconnection, L.L.C. [6]

The Commission's deliberations regarding the KP application may have prompted it to ask more broadly the question of whether the benefits of RTO membership are commensurate with the associated costs. Since, by virtue of its participation in MISO and as a signatory to the MISO transmission owners agreement,[7] LGE/KU has transferred functional control of its transmission

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6 Kentucky Power Company ("KP") filed an application with the KPSC requesting approval to transfer control of certain transmission facilities to PJM Interconnection, L.L.C. ("PJM"). Based on the evidence presented in the KP application and the subsequent hearing, the Commission concluded that the record failed to show that the transfer was "for a proper purpose and consistent with the public interest," and consequently it denied the request. *See* Kentucky Public Service Commission, "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," Case No. 2002-475, at page 3.

7 Midwest Independent System Operator, "Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc.," Appendices F and H, www.midwest.org, September 16, 1998.

facilities to MISO (completing this transaction in February 2, 2002), the Commission ordered LGE/KU to provide evidence that this transaction also was "consistent with the public interest."

The Commission has raised a fundamental question for restructuring of wholesale markets: Will regional control of transmission facilities, regional coordination of real-time dispatch and long-term expansion planning, and increased power market efficiencies (if any) give cost savings to LGE/KU's native load customers that are larger than their share of the transaction costs of creating and maintaining the regional institutions and markets?

### 1.2 Scope and Purpose of the Study

The decision to remain a member of MISO, operate as a stand-alone system, join an alternative RTO, or participate in a Kentucky state ISO is one that may have wide-ranging consequences for the company and its shareholders, as well as for LGE/KU's native load customers. Not all of the factors that must be considered in making a choice of this kind can be easily quantified, and even those that can be quantified are typically subject to great uncertainty, especially when the analysis seeks to value long-term benefits and costs.[8]

This analysis identifies and, to the extent possible, quantifies the principal drivers of the differences in the cost and benefits associated with staying in MISO relative to the three alternatives. These drivers include the following factors, which may significantly differ qualitatively and quantitatively among alternatives:

- revenues/profits from off system sales;
- opportunities to purchase economy power from a broader market;
- the quantity of transmission capacity investments;
- LGE/KU's share of the costs of transmission capacity investments;
- access to transmission service;
- allocation of transmission rights;
- transmission revenues;
- payments/costs of transmission service;
- reliability and planning benefits;
- system operations costs;
- LGE/KU's share of market implementation and administration costs;
- resource adequacy obligation;
- SMD implementation obligation;

[8] Kentucky Public Service Commission, "Investigation Into the Membership of Louisville Gas and Electric and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc." www. http://psc.ky.gov/pschome.htm, Case No. 2003-00266, at 3. The order requires LGE/KU to consider the costs and benefits for a 5 to 10 year period.

- obligation to pay MISO exit fees; and
- legal, regulatory and transaction costs.

From the perspectives of the KPSC and LGE/KU's customers, the decision about whether LGE/KU should be a member of an RTO or seek an alternative institutional arrangement, such as running a standalone system, rests on what institutional relationship enables LGE/KU to provide bundled energy service to native load customers at the lowest cost, subject to satisfying constraints on reliability and quality of service and meeting the companies' fiduciary duty to shareholders.

This study answered the following question: Is there an alternative RTO option or other institutional arrangement regarding the functional control of LGE/KU's transmission facilities that provides greater benefits at the same cost than the MISO option or provides an equivalent set of benefits to LGE/KU and its native load customers at a lower cost?

Based on the KPSC order, the study considers the costs and benefits, to the extent that they are quantifiable, over the period 2004 to 2010.

### 1.3 Summary of Cases

LGE/KU could pursue any one of several institutional arrangements with respect to ownership and control of its transmission facilities and participation in regional wholesale markets. The arrangements that are considered in this study are summarized in this section.

#### 1.3.1 Remain a Member of MISO

LG&E and KU became charter members of MISO over five years ago, and transferred control of their transmission facilities to MISO in February 2002.[9] The base case scenario has LGE/KU continue to be a MISO member. Under this scenario, MISO will take a growing share of planning and operational responsibilities from LGE/KU; and LGE/KU will pay a share of MISO's implementation and administration costs. The following highlights the key characteristics of the proposed LMP-based energy markets and congestion management system ("Day Two Market"):[10]

- *Tradable Services.* Beginning March 31, 2004, Market Participants will be able to buy and sell energy at market clearing prices in day-ahead and real-time energy markets operated by the Midwest ISO. Ancillary services outside of imbalance energy will continue to be procured by the existing Control Area Operators, during the first phase of the Midwest ISO energy markets.
- *Price Determination.*

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[9] Based on communication from L. Portasik, LGEE Senior Corporate Attorney and inferences drawn from a MISO press release "Midwest ISO Implements Next Phase of its Commercial Operations Plan: Begins Selling Regional Transmission Service," February 1, 2002.

[10] Midwest Independent Transmission System Operator, "Executive Summary – Energy Markets & FTRs," April 29, 2003.

- The Midwest ISO will create a Day-Ahead Schedule based on a security-constrained, least-cost dispatch model of the Midwest ISO Footprint with an external equivalent representation of contiguous areas to capture any loop flows. The results of this process will be financially binding. The model will also determine LMP values for each hour of the operating day for every bus in the network.
- The real-time energy market will settle on after-the-fact LMPs. Energy prices will be posted for each 5-minute interval at every bus.
- LMPs will reflect the marginal cost of losses and congestion.
- Uninstructed deviation penalties will apply to resources that do not follow dispatch signals within specified tolerance bands.

➢ *Trading Opportunities.*

- Market Participants will have the option of scheduling and settling at nodal prices or aggregated nodal prices.
- Purely financial bids (virtual demand bids and virtual supply offers) are permitted, to promote liquidity and consistency between the day-ahead and real-time markets.
- Resources that are dispatchable in real-time can offer energy into the real-time energy market.
- Congestion costs between two nodes will be calculated as the difference between the respective marginal prices at the two nodes.
- Buyers and sellers need not participate in the real-time or day-ahead energy markets. Self-schedules and bilateral transactions are allowed and accommodated.

➢ *Reliability Based Security Constrained Unit Commitment Process* ("RSCUC"). The Midwest ISO will conduct a RSCUC after the day-ahead market clears to ensure the availability of sufficient capacity to reliably operate the grid. Resources committed as part of the RSCUC process will be guaranteed recovery of their start-up and minimum-load offers.

The congestion management system will effectively create energy markets that run simultaneously with congestion management. These markets will be operated jointly to provide incentives for transmission and generation capacity to be allocated where it is most valuable.

### 1.3.2 Operate as a Standalone System

To become a standalone system, LGE/KU must withdraw from MISO. It would then operate essentially as it did prior to joining MISO and to turning functional control of its transmission facilities over to MISO. Under this alternative, LGE/KU would continue to be the system operator (i.e., control area operator), it would continue to be interconnected as it always has been, it would provide open access transmission service under an Order No. 888 tariff approved by FERC and take responsibility for all of the planning and operational functions that would be necessary to satisfy reliability and security standards imposed by the state, NERC, ECAR or the

FERC. In addition, LGE/KU would expect to be answerable to some NERC reliability authority (e.g., MISO or TVA).

### 1.3.3 Join an Alternative RTO-SeTrans RTO

Under this alternative, LGE/KU would join a non-MISO RTO such as SeTrans. Under this alternative, SeTrans would take a growing share of planning and operational responsibilities from LGE/KU; and LGE/KU would pay a share of SeTrans' costs.

The SeTrans RTO Day Two market is expected to consist of components very similar to those planned for the MISO Day Two market:

- A transparent, LMP-based, financially binding day-ahead and real-time two-settlement market system will be based upon a security-constrained economic dispatch that establishes schedules for the real-time market.
- LMP-based congestion charges will apply to transmission use.
- Loads will have the option of basing their settlements on either nodal prices or load-weighted zonal averages of LMPs.
- Ancillary service markets will be developed after a cost-benefit analysis is performed and the appropriate regulatory approvals are received.
- The FTRs allocated to existing firm customers will reflect the full capability of the system at the time of Day Two implementation. Unallocated capability will be auctioned. Grandfathered transmission agreements may convert to OATT service prior to Day Two and receive FTRs equivalent to prior physical rights. However, market processes will accommodate physical transmission rights represented in grandfathered agreements.
- A long-term planning reserve requirement applicable to all Load Serving Entities (LSEs).

This scenario is slightly more involved relative to MISO since LGE/KU can join SeTrans as either a participating transmission owner or a non-participating owner that has turned over functional control of transmission facilities to SeTrans. In addition, the scenario is complicated by the fact that the Day Two market in SeTrans at this point consists of a proposed high-level design. No detailed rules have been worked out. Thus, there is some uncertainty about the effects of a Day Two market implementation on LGE/KU should it choose to participate in the SeTrans RTO.

### 1.3.4 Establish a Statewide Independent System Operator

Under this alternative, LGE/KU would join a Kentucky statewide ISO ("KY-ISO") that is subject to FERC jurisdiction and designed to satisfy the requirements of FERC Order No. 2000.[11] This would require developing a tight power pool within the state from scratch. Thus, many of the functions performed by LGE/KU and MISO and services provided by MISO to its members would now be performed and provided by the KY-ISO.

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11 See Section 2.2.2 for discussion of the details of those requirements.

While the FERC may grant a waiver of the Order No. 2000 RTO scope and configuration characteristics, the KY-ISO would still have to satisfy a subset of the minimum set of RTO characteristics that would include provision of a real-time balancing market; market-based mechanisms to manage congestion and to deal with loop flows, price congestion and imbalances efficiently; tradable transmission rights; provision of last resort for ancillary services; operation of a single OASIS for all transmission under its control; calculation of Total Transmission Capacity and Available Transmission Capacity; planning and coordination of transmission upgrades and additions, including coordination with the KPSC and other state regulators as necessary; and development of mechanisms to coordinate its activities with other regions, whether or not an RTO exists in those regions, especially concerning reliability and market interfaces.

## 2. BACKGROUND

In this section, we discuss LGE/KU's physical configuration, regulatory situation, and present relationship with MISO. This discussion is pertinent to establishing quantitative estimates of the relative costs and benefits of the RTO options.

### 2.1 LGE/KU's Physical Configuration

Louisville Gas and Electric Company and Kentucky Utilities Company are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. Both companies are subsidiaries of LG&E Energy Corp. As the owners and operators of interconnected electric generation, transmission and distribution facilities, the combined companies achieve economic benefits through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

The combined LGE/KU system has a net summer generation capacity of 7,065 MW. LG&E and KU together serve 877,278 electricity customers over a transmission and distribution network covering 27,000 square miles. The KU portion of the combined system supplies generation, transmission and distribution service in 77 counties of Kentucky. KU also sells electric energy at wholesale for resale to 11 Kentucky municipalities, to Berea College (in Kentucky) and to the municipality of Pitcairn, Pennsylvania. The LG&E portion of the combined system supplies electricity (and natural gas) to customers in the Louisville metropolitan area and 16 surrounding counties.

#### 2.1.1 Energy and Demand Projections

Energy and demand affect the relative costs to LGE/KU of remaining in MISO or of pursuing one of the alternatives since the system operations costs recovered through MISO and SeTrans Open Access Transmission Tariffs (OATTs) are mostly based on energy and demand billing determinants. Hence, LGE/KU's payments to MISO or SeTrans may increase (decrease) over the study period if the rates of growth of energy and demand in the LGE/KU service territory are larger (smaller) than the corresponding rates in the rest of MISO or SeTrans.

LGE/KU's produced the principal energy forecast that was used in this study. It was based upon a base case scenario utilizing national macroeconomic growth assumptions from Global Insight and service territory-specific economic and demographic forecasts from the University of Kentucky.[12] The forecast is summarized in Table 2.1.[13]

**Table 2.1. LGE/KU Energy Sales to and Seasonal Demand by Ultimate Customers**

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|
| Energy Sales (GWh)[14] | 32,780 | 33,502 | 34,455 | 35,105 | 35,726 | 36,493 | 37,236 |
| Energy Sales + Sales for Resale[15] | 42,988 | 43,934 | 45,184 | 46,037 | 46,852 | 47,857 | 48,831 |
| Summer Peak (MW) | 7,027 | 7,209 | 7,405 | 7,619 | 7,735 | 7,805 | 7,981 |
| Winter Peak (MW) | 6,202 | 6,351 | 6,507 | 6,604 | 6,617 | 6,906 | 7,137 |

Energy sales projections imply that over the period 2004 to 2010, the MWh sold to ultimate customers and wholesale customers (i.e., municipalities) will grow at an annual average rate of 2.32%. In 2005, total sales are expected to be 33.5 million MWh and by 2010 are expected to grow to 37.2 million MWh.

The combined company seasonal demand forecast over the study period is also summarized in Table 2.1. The annual growth rate over the study period is roughly 2%, slightly less than the growth rate assumed for demand in the rest of MISO (between 2.3% and 3%).[16]

### 2.1.2 Generation Portfolio Capacity

LGE/KU's power generating system consists of 20 coal-fired units operated at 7 different steam generating stations; 2 oil-fired units; and gas-fired and oil-fired combustion turbines supplement the system during peak periods. The system is further augmented by hydroelectric facilities at Dix Dam, Lock 7 and Ohio Falls. The generating capability of the LGE/KU system is

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12 The Global Insight and University of Kentucky forecasts used for this scenario were taken as given by the study team for this project. The assumptions for the scenario were discussed in the October 2002 IRP filing.

13 Energy forecasts for KU and LG&E are developed using consistent methods. The energy forecast prepared by each company is used to generate individual and combined demand forecasts. For the combined system, the separately estimated demand forecasts are not additive due to the non-coincidence of system peaks. The companies' energy forecasts are based on econometric modeling techniques combined with growth forecasts from the companies' largest customers. Note that the peak values are before curtailment of interruptible load.

14 Based on the LG&E Energy 2002Energy Sales Projections, spreadsheet provided by R. Siewert. Does not include sales for resale.

15 Based on LG&E Energy 2002 Energy Sales Projections, includes sales for resale.

16 The Midwest ISO Transmission Expansion Plan used growth rates for the remainder of MISO that vary from 2.3% to 3% for the 5-year planning period 2002-2007. This suggests that LGE/KU's share of the costs might decline somewhat over time. See Midwest Independent Transmission System Operator, Inc., "Midwest ISO Transmission Expansion Plan 2003," Approved by the Midwest ISO Board of Directors, June 19, 2003, Section 8, Scenario-Based LMP Analyses.

summarized on Table 2.2.[17] The total nameplate capacity of the system is 8,084 MW. The net summer capacity is 7,038 MW.

**Table 2.2 Capacity of Native Generation in 2002 (MW)**

| Plant Type | Nameplate | Net Winter | Net Summer | Gross Winter | Gross Summer |
|---|---|---|---|---|---|
| Coal | 6,270 | 5,367 | 5,362 | 5,737 | 5,739 |
| Peaking[18] | 1,703 | 1,776 | 1,604 | 1,787 | 1,612 |
| Hydro | 110 | 56 | 72 | 56 | 72 |
| Total System | 8,084 | 7,199 | 7,038 | 7,580 | 7,423 |

In addition to the owned capacity listed in Table 2.1, LGE/KU has entered into purchased power agreements (PPAs) with Owensboro Municipal Utilities, Electric Energy, Inc., and Ohio Valley Electric Corporation. The capacity under these PPAs is just under 600 MW.

**Table 2.3 Net Summer Capacity vs. Peak Demand (MW)**

| Year | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|
| Net PPA Capacity | 593 | 583 | 573 | 563 | 553 | 543 | 533 |
| Native Generation | 7,038 | 7,038 | 7,038 | 7,038 | 7,038 | 7,038 | 7,038 |
| Total Net Summer Peak Capacity | 7,631 | 7,621 | 7,611 | 7,601 | 7,591 | 7,581 | 7,571 |
| Peak Summer Demand[19] | 7,027 | 7,209 | 7,405 | 7,619 | 7,735 | 7,805 | 7,981 |
| Less Interruptibles/Other | 180 | 202 | 223 | 241 | 249 | 249 | 249 |
| Net Peak Demand | 6,847 | 7,007 | 7,182 | 7,378 | 7,486 | 7,556 | 7,732 |
| Peak Demand + Reserve Margin (14%) | 7,806 | 7,988 | 8,187 | 8,411 | 8,534 | 8,614 | 8,814 |
| Capacity Shortfall without Additions | -175 | -367 | -577 | -810 | -943 | -1,033 | -1,244 |
| Cumulative Planned Capacity Additions | 296 | 444 | 592 | 888 | 1437 | 1437 | 1437 |

Table 2.3 compares LGE/KU's total capacity, both owned and under PPAs, to its net summer peak load plus reserve margins for years 2004 through 2010.[20] The target reserve margin used for planning purposes is assumed to be 14%. Consequently, without any additions to native capacity,

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17 Excel Spreadsheet: "Kentucky Utilities Company/Louisville Gas and Electric Company 2003 Generator Rating," June 1, 2003, Revised July 1, 2003, provided by Robin Siewert, August 12, 2003.

18 Peaking units include Brown CTs, Haefling, Trimble CTs, Tyrone 1&2, and LG&E CTs.

19 From Table 2.1.

20 The steady reduction over time in net capacity available from PPAs is due to the increase in own load served by the generating units of one of the utilities with which LGE/KU has an agreement. We assumed that the available capacity was reduced by a constant 10 MW per year. No increases in native generation capacity have been included, even though the companies' integrated resource plan includes potential capacity additions.

PPAs or interruptibles, LGE/KU total net summer capacity of the system falls short of summer coincident peak demand plus reserve margin throughout the study period. LGE/KU plans to build generating capacity of about 1,437 MW over the period 2004 to 2008. Without this capacity, LGE/KU must purchase capacity from others, either through long-term contracts or short-term purchases. With this capacity, LGE/KU will in 2008 have excess capacity of about 500 MW that could be sold off system.

### 2.1.3 Transmission System

Figure 2.1 presents a map that lays out the topology of the LGE/KU transmission system and its interconnections with neighboring control areas. Table 2.4 summarizes the mileage of LGE/KU's high-voltage transmission system, by voltage level. Table 2.5 lists the LGE/KU system's major interconnections with neighboring systems.

**Table 2.4. Mileage of High Voltage Transmission Lines**

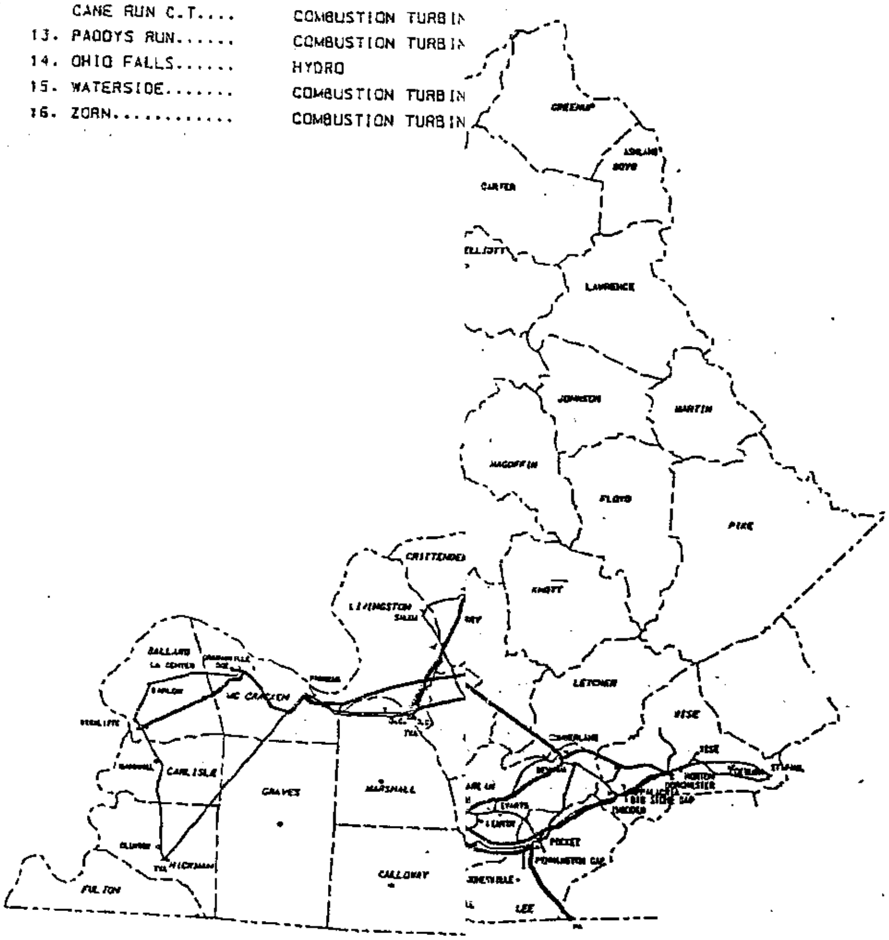
| Voltage Level | Mileage |
|---|---|
| 500 kV and 345 kV | 562 |
| 161 kV and 138 kV | 1,874 |
| Less than 100 kV | 2,717 |
| Total | 5,153 |

A principal feature of the LGE/KU system is the weak linkage between the eastern and western portions of the system – that is, between the old KU and LG&E portions of the system. Furthermore, there is a persistent constraint in southern Indiana (the Petersburg 345/138 kV transformer). The heavy loading of this transmission element arises from local load and regional power transfers. The latter is due to the limited number of high-voltage lines from southern Indiana into Kentucky and Kentucky into Tennessee. Consequently, power transfers out of and through the region utilize the lower voltage circuits, loading up other transformers in the area. The Petersburg 345/138 kV transformer will likely continue to be loaded near its 170 MW limit during peak periods into the future. What this means generally is that north-to-south transfers of power have a significant impact on power flows on the LGE/KU system.

GENERATION STATIONS

| | | |
|---|---|---|
| 1. | E.W. BROWN..... | STEAM |
| 2. | BROWN C.T...... | COMBUSTION TURBIN |
| 3. | DIX DAM......... | HYDRO |
| 4. | GHENT......... | STEAM |
| 5. | GREEN RIVER.... | STEAM |
| 6. | HAEFLING........ | COMBUSTION TURBIN |
| 8. | LOCK SEVEN....... | RUN OF RIVER |
| 9. | TYRONE......... | STEAM |
| 10. | TRIMBLE CO..... | STEAM |
| 11. | MILL CREEK.... | STEAM |
| 12. | CANE RUN....... | STEAM |
| | CANE RUN C.T.... | COMBUSTION TURBIN |
| 13. | PADDYS RUN...... | COMBUSTION TURBIN |
| 14. | OHIO FALLS...... | HYDRO |
| 15. | WATERSIDE....... | COMBUSTION TURBIN |
| 16. | ZORN............ | COMBUSTION TURBIN |

N




SCALE

10 0 10 20 30 40 MILES

10 0 10 20 30 40 50 KILOMETERS

02-26-02

**Table 2.5 Control Area Interconnections 138 KV and Above**

| Control Area Interconnections | Interconnection Name | Interconnection Size (KV) |
|---|---|---|
| Tennessee Valley Authority | Pocket North to Phipps Bend | 500 |
| | Livingston County to Calvert City | 161 |
| | Livingston County to Kentucky Dam | 161 |
| | Paddys Run to Summersdale | 161 |
| | Pineville Switching to Pineville | 161 |
| Southern Indiana Gas & Electric | Cloverport to Newtonville | 138 |
| Cinergy | Ghent to Batesville | 345 |
| | Ghent to Speed | 345 |
| | Beargrass/Northside to Jeffersonville | 138 |
| | Ghent to Fairview | 138 |
| | Northside to Speed | 138 |
| | Paddys West to Gallagher | 138 |
| Big Rivers Electric Cooperative | Green River to Wilson | 161 |
| | Cloverport to Hardinsburg | 138 |
| | Hardinsburg to Hardinsburg | 138 |
| East Kentucky Power Cooperative | Blue Lick to Bullitt County | 161 |
| | Delvinta to Beattyville/Powell County | 161 |
| | Delvinta to Green Hall | 161 |
| | Elihu to Cooper | 161 |
| | Lebanon to Marion County | 161/138 |
| | Beattyville to Delvinta/Powell County | 161/69 |
| | Pittsburg to Laurel County/Tyner | 161/69 |
| | Taylor County to Green County/Marion County | 161/69 |
| | Fawkes to Fawkes | 138 |
| | Fawkes/Lake Reba to Fawkes | 138 |
| | Ghent to Gallatin County | 138 |
| | Goddard to Goddard/Plumville | 138 |
| | Kenton (91-744) to Spurlock | 138 |
| Ohio Valley Electric Cooperative | Trimble County to Clifty Creek | 345 |
| | Carrollton to Clifty Creek | 138 |
| | Northside to Clifty Creek | 138 |
| American Electric Power | Kenton to Hillsboro | 138 |

## 2.2 LGE/KU's Regulatory Situation

### 2.2.1 Kentucky State Regulatory Requirements

Under the Kentucky Revised Statutes ("KRS") (KRS 278.020(4)),

> No person shall acquire or transfer ownership of, or control, or the right to control, any utility under the jurisdiction of the commission by sale of assets, transfer of stock, or otherwise, or abandon the same, without prior approval by the commission. The commission shall grant its approval if the person acquiring the utility has the financial, technical, and managerial abilities to provide reasonable service.[21]

This paragraph was not part of the applicable law at the time LGE/KU became a member of MISO and therefore may not be relevant to its decision to remain a member of MISO.[22] However, a decision to change the institutional relationship from MISO to an alternative will likely require approval by the KPSC.

#### 2.2.2 FERC's RTO/ISO Policy

The overriding reform goal motivating FERC's reformation of the wholesale market is to create new governance arrangements for the electricity sector that will improve its efficiency and thereby provide long-term benefits to consumers. FERC believes that such benefits can accrue through reliance on competitive wholesale power markets that provide better incentives for controlling capital and operating costs of new and existing generating capacity; that encourage cost-reducing trades among market participants; that encourage innovation in power supply technologies; and that shift the risks of technology choice, construction cost and operating "mistakes" to suppliers and away from consumers.

Significant portions of the total costs of electricity supply — distribution and transmission — will continue to be regulated. Accordingly, there are at least two reasons that reforms of traditional regulatory arrangements governing the distribution and transmission networks have generally been viewed as an important complement to the introduction of wholesale and retail competition to supply consumer energy needs. First, regulatory mechanisms with good incentive properties would lead to lower distribution and transmission costs, and this would help to reduce retail electricity prices. During the first decade of the electricity restructuring and competition program in England and Wales, as much as 35% of the reduction in real electricity prices was associated with cost reductions in distribution and transmission. Second, the efficiency of wholesale markets depends on a well functioning supporting transmission network and its efficient operation by a system operator. Good operating and investments incentives are important for providing an efficient network platform upon which wholesale and retail competition could develop.

Since the passage of the Energy Policy Act of 1992, FERC has been attempting to restructure the electric industry to foster competitive wholesale electricity markets. After pursuing this objective under the existing industry structure through its landmark 1996 Orders No. 888 and No. 889, FERC concluded that it must create regional transmission organizations (RTOs) to achieve the goal of fostering competitive markets. In Order No. 2000, FERC called upon jurisdictional

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21 Kentucky Revised Statutes, KRS Chapter 278.00, Public Utilities Generally, § 020, Certificate of convenience and necessity required for construction provision of utility service or of utility—Exception – Approval required for acquisition or transfer of ownership—Severability of provisions.

22 We leave legal opinions to others better qualified to make such determinations.

transmission-owning utilities to create RTOs and to voluntarily transfer control of grid operations to their respective RTOs.[23]

FERC's Order No. 2000 defines the minimum requirements that every RTO and ISO must meet, while suggesting (without mandating) preferred approaches for meeting each requirement. In particular, Order No. 2000 requires that every RTO and ISO provide at least the following support for regional markets:

- An RTO/ISO must provide a real-time balancing market and ensure that all parties have non-discriminatory access to this market.
- An RTO/ISO must provide market-based mechanisms to manage congestion within the region and to deal effectively with transmission loop flows, rather than rely on administrative transmission loading relief ("TLR") curtailments.
- An RTO/ISO must price congestion and imbalances efficiently, so that generators and other parties have appropriate price signals to encourage efficient short-run operations and long-run investments.
- An RTO/ISO must offer tradable transmission rights that allow parties to hedge locational differences in energy prices resulting from congestion. These rights must support efficient regional dispatch and provide efficient incentives.

In addition, Order No. 2000 defined four minimum characteristics and eight minimum functions that any entity seeking approval from FERC for RTO or ISO status must satisfy. The four minimum characteristics for an RTO are: independence, appropriate geographic scope and regional configuration, operational authority for all transmission facilities under the RTO's control, and exclusive short-term reliability authority. FERC indicated in its White Paper, that a final rule on SMD will require ISOs only satisfy the latter two characteristics. The eight required functions are:

- develop and administer transmission tariffs that promote efficient use and expansion of transmission and generation facilities,
- develop congestion management procedures,
- develop and implement loop flow and parallel path procedures,
- serve as the provider of last resort for all ancillary services,
- operate a single OASIS (Open-Access Same-Time Information System) for all transmission under its control, and be responsible for independently calculating Total Transmission Capacity and Available Transmission Capacity,
- monitor markets to assess market power and market design flaws, and propose remedies,
- plan and coordinate necessary transmission upgrades and additions, including coordinating its efforts with state regulators, and

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23 Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (2000), FERC Stats. & Regs. ¶ 31,092 (2000), aff'd, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

- develop mechanisms to coordinate its activities with other regions, whether or not an RTO exists in those regions, especially concerning reliability and market interfaces.

Missing from Orders No. 888 and No. 2000 was any specific guidance on market design and structure. FERC attempted to take that last step through its Notice of Proposed Rulemaking on Standard Market Design ("SMD NOPR") issued in July 2002.[24] This well intentioned initiative generated severe and widespread criticism, inducing FERC to subsequently issue a White Paper that withdrew a number of the more controversial elements without fully resolving the federal-state jurisdictional rift.[25] In the White Paper, FERC provided transmission owners with a promise of some flexibility in determining how they comply with Order No. 2000. The FERC has indicated in the White Paper that, in its final rule on SMD and wholesale restructuring (should there be one), it intends to require all transmission-owning public utilities to join either an RTO or an ISO.[26] An ISO must meet all of the RTO characteristics and functions listed in Order No. 2000, but will not be held to the scope and configuration requirements for RTOs. However, ISOs will be required, through inter-regional coordination agreements with neighboring RTOs and ISOs, to address issues that create seams problems that are perceived to limit wholesale power trading, such as rate pancaking and congestion management and pricing.

## 2.3 LGE/KU's Relationship with MISO

### 2.3.1 Services Provided by MISO to LGE/KU

MISO does not currently operate as a single unified control area or perform all of the functions that are provided by other RTOs that do function as single control areas. We summarize the basic services that MISO provides to its members below.[27]

*Security coordination.* MISO provides security coordination services involving real-time oversight and administration of bulk electric system activity in the RTO region. Computer systems analyze forecasted and actual system conditions. Voice and data communication networks enable communication between the Midwest ISO, its members and neighboring regions.[28] MISO is responsible for real-time system monitoring, evaluation and coordination of the operation of the electric power system. MISO responds to system contingencies with actions such as line loading relief, load shedding, schedule curtailment and redispatch. MISO has the authority to order emergency energy schedules.

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[24] Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, 100 FERC ¶ 61,138 (2002).

[25] White Paper, Wholesale Power Market Platform, Issued April 28, 2003, in Docket No. RM01-12-000.

[26] Depending on the outcome of Congressional deliberations on federal energy legislation containing a electricity restructuring provisions, there is the great likelihood that a final rule on SMD will not be issued before the end of 2005 and perhaps later. However, we do not base our evaluations or conclusions on any speculation of what either the FERC or the Congress will do in the future.

[27] The material in this section has been drawn from http://www.midwestiso.org/about_us.shtml, MISO's web page, August 20, 2003.

[28] The Midwest ISO's control center will be the largest of its kind in the U.S., with systems capable of managing a 50,000 bus system.

*Outage coordination.* MISO performs consolidated assessments of planned maintenance outages of all member transmission owners, taking into account all known scheduled and forced outages throughout the Eastern Interconnection. For example, MISO developed an operating guide for LGE/KU, East Kentucky Power Cooperative ("EKPC"), and the Tennessee Valley Authority ("TVA") to mitigate overloads in the Kentucky transmission system due to several scheduled Cinergy 345 kV transmission outages planned in November 2002. MISO coordinated efforts among EKPC, TVA and LGE/KU to establish a working plan to mitigate overloads of an LGE/KU-EKPC tie line, an LGE/KU transmission line and a Cinergy-AEP tie line.[29]

*Voltage security analysis studies.* MISO performs seasonal studies of the LGE/KU and neighboring interconnected transmission systems including voltage security assessments, detection of transmission voltage problems, development of action plans, and operational measures to ensure that the transmission system remains in a secure state.[30] These studies have analyzed projected potential voltage degradations in the LGE/KU transmission system due to power flows on the interconnections.

*Current-day and next-day security analysis.* MISO performs daily voltage security assessments that can predict overloads of key transmission facilities and lead to the preparation of operational measures to mitigate the overloads in a secure manner. As an example, to avoid transmission loading relief (TLR) calls, MISO has prepared studies that provide specific generation redispatch recommendations to LGE/KU.

*Long-term regional planning.* MISO is required to engage in long-term regional planning. MISO staff examines a number of factors, including need, cost effectiveness, the ability to meet the diversity of generation sources, impact on the environment and reliability. MISO prepares regional transmission expansion plans ("RTEPs") on a regular basis.

*Scheduling.* MISO processes transmission service requests and generator interconnection requests. MISO scheduling coordinators serve as the liaison between the buyer and seller in a power transaction.

*OASIS.* MISO maintains and operates an OASIS that conforms to FERC's requirements.

*Tariff administration.* MISO administers the OATT, including the terms, conditions, and rates applicable to various types of electric transmission service.

*Ancillary services provision.* MISO anticipates developing and administering an ancillary services market. It currently operates as the provider-of-last-resort for ancillary services as required by FERC in Order No. 2000.

*Market monitoring.* MISO has an independent market monitor who develops market power monitoring and mitigation procedures that will determine whether any market activity is significantly undermining the efficiency of MISO's markets.[31]

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29 MISO presentation to LGE/KU management, August 5, 2003.

30 *Ibid.*

31 Market monitoring is one function that LGE/KU does not need as a regulated standalone entity, as KPSC regulation is sufficient to assure just and reasonable rates.

### 2.3.2 LGE/KU's Obligations to MISO

Most of the functions and services that MISO provides under the Transmission Owners Agreement ("TOA") to LGE/KU are functions that LGE/KU has provided itself historically and will continue to self-provide to the extent that MISO does not or cannot provide them.[32]

As a transmission owner (TO) in MISO, LGE/KU has certain rights, powers and obligations as defined by the TOA. The obligations pertain to operations and planning, maintenance, facility expansion and tariff administration.

*Operations and planning.* As the control area operator, LGE/KU must follow the directions of MISO in operating its transmission system, dispatching generation, providing reactive supply and voltage control, and curtailing load. This means that LGE/KU is responsible for monitoring the flows on its system and for actual dispatch of generation, at least until the spring of 2004, when the Day Two market is expected to be in operation. In addition, as a control area operator, LGE/KU is responsible for balancing its control area load and generation in real time, and will continue to have that responsibility in the Day Two market. With regard to TLR curtailment events and interregional emergencies, LGE/KU must follow directions from MISO but still is in control of the balancing function. With regard to planning, LGE/KU is responsible for developing its own long-term expansion plan, subject to review and approval by MISO.

*Maintenance.* LGE/KU is required to maintain its transmission facilities in accordance with good utility practice and follow the generation and transmission maintenance requirements set forth in Appendix E to the MISO TOA.

*Construction.* LGE/KU is expected to use due diligence to construct transmission facilities as directed by the Midwest ISO subject to any siting, permitting, and environmental constraints imposed by state, local, and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals. In turn, LGE/KU would expect under the TOA to be fully compensated for the costs of construction undertaken by it according to the transmission tariff and Appendix C of the TOA.

*Pricing and revenue distribution.* Under the TOA, LGE/KU will take network or point-to-point service under a service agreement and under the terms and conditions of the MISO OATT. However, since LGE/KU takes network integration transmission service to serve its native load under a bundled retail service tariff and self-provides all ancillary services and network services (including loss responsibility), LGE/KU is not required to pay additional charges associated with Schedules 1 through 6 and Schedule 9 or to be responsible for paying MISO for losses associated with network resources located within the LGE/KU control area or pricing zone.[33] However, it is responsible for losses of any network resource located outside the LGE/KU control area or

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[32] Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, "Agreement of the Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., A Delaware Non-stock Corporation," Accepted by FERC Order Dated September 16, 1998 ("MISO OATT").

[33] Schedules 1 through 6 in the MISO OATT define rates for the six required ancillary services: (1) scheduling, system control and dispatch, (2) reactive supply and voltage control, (3) regulation and frequency response, (4) energy imbalance and inadvertent interchange, (5) spinning reserves, and (6) supplemental reserves. Schedule 7 defines rates for long-term and short-term firm point-to-point transmission service. Schedule 8 defines rates for non-firm point-to-point transmission service. Schedule 9 defines rates for network integration transmission service.

pricing zone. In addition, LGE/KU will be responsible for Schedule 10, 16, and Schedule 17 charges, for which it will have an "exit fee" obligation if it withdraws from MISO.

## 3. PRINCIPAL DRIVERS OF DIFFERENCES IN COSTS AND BENEFITS

In this section, we consider the elements of LGE/KU's business that are likely to have benefits or costs that are different under the four RTO scenarios.

### 3.1 Off-System Sales and Economy Power Purchases

LGE/KU's trading opportunities are not expected to be significantly different under the four RTO alternatives. MISO membership has the advantage of allowing greater automation of LGE/KU's short-term (day-ahead and real-time) trades with its major trading partners, as these trades will (eventually) be implicit in MISO's commitment and dispatch. As a standalone entity, or as a member of the SeTrans RTO or a Kentucky ISO, LGE/KU would have to identify and implement its short-term trades with MISO and PJM members. SeTrans membership or participation in a Kentucky ISO would give LGE/KU similar opportunities to trade within these RTOs as membership in MISO gives for opportunities to trade within MISO; but these opportunities would provide LGE/KU with relatively small benefits because of LGE/KU's relatively smaller volume of trade with SeTrans members and virtually no additional opportunities within a Kentucky ISO. Relative to the MISO membership case, the major disadvantage and cost of joining the SeTrans RTO is that LGE/KU is not directly electrically interconnected to SeTrans. LGE/KU would have to drive through TVA, which would introduce a rate pancake and may limit severely LGE/KU's ability to become integrated into SeTrans.

LGE/KU's opportunities to sell and purchase reserve services are independent of all RTO options. The existing reserve sharing arrangement in the East Central Area Reliability Council ("ECAR"), of which LGE/KU has been a member since its inception, is independent of the RTO option pursued.

The value that LGE/KU can achieve from off-system sales and the cost savings that it can gain from economy power purchases depend upon at least two major factors. One is the efficiency of the regional commitment and dispatch. The second factor is the way that transmission and energy services are priced. These are discussed below.

#### 3.1.1 Efficiency of Regional Commitment and Dispatch

In principle, it will usually be impossible for a region with many system operators to achieve the same low-cost commitment and dispatch that can be achieved by a single regional system operator. A single regional system operator should ordinarily have the information, software, and communications systems needed to determine the lowest achievable cost of regional commitment and dispatch. Division of a region into many system operations areas, by contrast, can result in least-cost commitment and dispatch *within each area* but can achieve the lowest regional costs only if market participants in each of the areas find all of the possible cost-reducing trades with participants in other areas. Because of time and information constraints, it will usually be difficult, if not impossible, for market participants to find all of these. Furthermore, it is very difficult for multiple system operators to provide 10-minute operating reserves as cheaply as a single regional system operator can; and it is impossible for multiple system operators to provide regulation service as cheaply as a single regional system operator. On the other hand:

- MISO will encompass roughly 23 control areas; so the efficiencies that are achievable by unified system operations in *principle* may not be available to MISO members in *practice*.
- LGE/KU is so poorly interconnected with SeTrans that it is difficult to see how a SeTrans commitment and dispatch that include LGE/KU could result in a significantly more efficient regional power system than one that does not include LGE/KU; and because of LGE/KU's strong interconnections with MISO, it is extremely unlikely that it would capture the efficiencies of a MISO commitment and dispatch that included LGE/KU. For SeTrans membership to result in any efficiencies at all, LGE/KU would need to be electrically integrated into the SeTrans system through a sizeable long-term firm transmission service contract through TVA – which may be unavailable or available at too high a cost. Without such firm transmission capacity, it will simply not be possible for SeTrans to achieve a lower-cost commitment and dispatch than LGE/KU and SeTrans could achieve as completely separate entities, or that could be achieved with LGE/KU as a MISO member. Furthermore, because of LGE/KU's strong interconnection with MISO, the achievement of an efficient SeTrans commitment and dispatch that included LGE/KU would not address the problem of identifying the cost-reducing and efficiency-enhancing trades between LGE/KU and MISO. In this regard, the SeTrans membership scenario offers no benefits relative to the LGE/KU standalone scenario, and is inferior to the MISO membership scenario.
- Kentucky is so small that joint commitment and dispatch by a Kentucky state ISO could, at best, lead to small efficiencies relative to separate commitment and dispatch; and it is extremely unlikely that it would capture the efficiencies of a MISO commitment and dispatch that included LGE/KU.

For LGE/KU, the efficiency of regional commitment and dispatch is important because LGE/KU is one of the entities that are sharing a part of the regional pie: the more efficient the region is, the larger the pie. Off-system sales and purchases are a key mechanism by which LGE/KU gets a share of the pie, regardless of whether it is an RTO member. It is difficult to know in advance: a) how much, if at all, the costs of regional commitment and dispatch with LGE/KU outside of an RTO will exceed those costs with LGE/KU inside of an RTO; and b) whether LGE/KU's share of the pie will be larger if it is an RTO member (in which case its short-term trades with other RTO members will be implicit in the RTO commitment and dispatch) or if it is not an RTO member (in which case its short-term trades with RTO members will be explicit).

#### 3.1.2 Pricing of Transmission and Energy Services

LGE/KU can expect to benefit from the elimination of rate pancaking in MISO, PJM, and (to a lesser extent) SeTrans; but this benefit may be obtained regardless of whether LGE/KU is a member of an RTO. Insofar as there could be lower-cost power priced either in MISO or PJM, with the elimination of regional through and out rates between PJM and MISO (and for AEP regardless of what RTO it ultimately joins), LGE/KU could purchase economy power without having to pay transmission fees other than LGE/KU's zonal point-to-point access fee.

Regardless of whether LGE/KU is a MISO member:

- The net price that LGE/KU sees for its real-time trades with MISO members will be based upon the LMPs at the interconnections between LGE/KU and the neighboring MISO transmission system.
- The net price that LGE/KU sees for its longer-term trades with MISO members will reflect expectations of the LMPs at the interconnections between LGE/KU and the neighboring MISO transmission system.

The only significant effect of MISO membership on LGE/KU's opportunities to trade with MISO members would arise from the way that transmission access charges and system operations charges are levied. Because these charges are levied on MISO loads, exports, generation, and imports, LGE/KU would pay these charges on all of its load and generation if it were a MISO member but would pay them only on its purchases from and sales to MISO members if it were not a member. Thus, if LGE/KU were a MISO member, it would pay the same amount for these charges regardless of its trades with other MISO members; but if LGE/KU were not a MISO member, it would pay these charges only for trades with MISO members. Consequently, although these charges would act as a minor barrier to trade with MISO members regardless of LGE/KU's relationship with MISO, they will be a larger barrier to trade with MISO members if LGE/KU were not a MISO member. This would occur because, if LGE/KU were a MISO member, it could regard these charges as a fixed cost and thus ignore them in arranging trades with MISO members; but if LGE/KU were not a MISO member, it would need to consider that it would pay these charges only if it conducted trades with MISO members, which could cause LGE/KU to forego some marginal trades with MISO members in favor of trades with non-MISO entities or in the case of off-system purchases, in favor of self supply.

As with its sales opportunities, LGE/KU's purchase opportunities should benefit from unified regional commitment and dispatch and from the elimination of transmission rate pancaking. In 2001-2003, LGE/KU imported about 1.3% (i.e., roughly 500 GWh annually) of the native load requirement.[34] Imported energy is expected to remain a relatively stable proportion of total sales over the study period. Hence, the absolute value of imports will increase, and along with it fuel cost. However, with the elimination of rate pancaking not only within MISO but between MISO and PJM, it is conceivable that purchase and sales opportunities may grow as a proportion of total output.

### 3.2 The Quantity of Transmission Capacity Investments

It is not clear how LGE/KU's choice of RTO might affect transmission investments either within or outside of LGE/KU's service territory, or whether such effects might be significant.

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[34] In 2002, LGE/KU sold 28,541 GWh to ultimate customers, and the total of all sales was 41,584 GWh, the difference largely due to wholesale sales-for-resale. For 2002, 1.3% of total sales would equal 540 GWh. Federal Energy Regulatory Commission, "Form 1, Annual Report for Major Electric Utilities, Licensees and Others for the Year Ended December 31, 2002."

LGE/KU's membership in an RTO can involve three types of transmission capacity investments. First, LGE/KU could invest in transmission upgrades or expansion to ensure the reliability of its own grid and to minimize the overall cost of resources serving its own native load customers. Second, LGE/KU would have a responsibility to build transmission that might primarily benefit other RTO members, raising the question of how much of the cost of that investment would be allocated to LGE/KU's native load customers. And third, transmission investment made by other transmission owners in the RTO may benefit LGE/KU's native load customers, raising the question of how much of the cost of that investment would be allocated to LGE/KU. The extent to which each of these kinds of investments happen will depend upon policy and cost allocation decisions that have not been fully addressed (or addressed at all) by MISO, SeTrans, or the non-existent Kentucky ISO. Consequently, it is not possible to determine the extent to which the quantity of transmission investments may be affected by LGE/KU's RTO decision.

### 3.2.1 As a MISO Member

At this point, LGE/KU has not been asked to upgrade or expand its transmission system to satisfy the needs identified by MISO in its Midwest Transmission Expansion Plan. However, there are several projects that could conceivably involve LGE/KU in additional investment to benefit the wider region.

### 3.2.2 As a Standalone System

LGE/KU would be expected to follow the program of transmission upgrades and expansion detailed in the 2002 IRP.

### 3.2.3 As a SeTrans Member

Because of the weak interconnections between LGE/KU and SeTrans, it is difficult to see how transmission investments in the LGE/KU system might benefit other SeTrans members, nor how transmission investments in other parts of SeTrans might benefit LGE/KU. Loop flows and the accompanying investment synergies are simply non-existent.

The most likely effect upon transmission investment of LGE/KU's membership in SeTrans would be to induce upgrades and expansion on the links between LGE/KU and other SeTrans members. Such upgrades and expansion might be required to permit a reasonable volume of trade and degree of system control between LGE/KU and other members. It seems unlikely, however, that such upgrades or expansion could be economic given the distance between LGE/KU and SeTrans and the fact that utilities have historically found it uneconomic to build significant linkage between LGE/KU and any SeTrans member.

### 3.2.4 Within a Kentucky ISO

With a Kentucky ISO, the relative quantity of transmission capacity investments in Kentucky may be larger than under the other alternatives. The reason is that transmission links within the state are relatively weak;[35] and a statewide ISO might be tempted to strengthen these links, even if they made little economic sense. Indeed, the absence of such strong links are *prima facia* evidence that such investments would be uneconomic or at least have not been found to be economic historically.

### 3.3 LGE/KU's Share of the Costs of Transmission Capacity Investments

Because of the ambiguities and incompleteness in the RTOs' rules for allocating transmission costs among RTO members, it is not yet possible to determine the extent to which the costs of LGE/KU's transmission investments will be shared by other RTO members or the extent to which LGE/KU will have to pay for investments made by others. As a standalone system, LGE/KU and its native load customers will bear full responsibility for the costs of transmission capacity investments within the LGE/KU system and, aside from upgrades that LGE/KU may request to serve specific transactions, it will not be responsible for any of the costs of upgrades to other transmission owners' systems. As an RTO member, the situation is less clear. As a member of a non-existent Kentucky ISO, LGE/KU's share of others' system upgrades is even murkier.

#### 3.3.1 As a MISO Member

Attachment N of the MISO OATT outlines how costs of network upgrades will be allocated among transmission owners and customers. Under Attachment N, it is conceivable that LGE/KU could share responsibility for the costs of system upgrades or expansions constructed by other transmission owners within MISO. Generally, the costs of network upgrades will be borne by transmission customers under direct assignment rules, until such time as the transmission owner constructing the upgrade has received approval to recover network upgrade costs in its rates. However, a transmission owner may elect to have all costs of network upgrades that it constructs on its system rolled into its zonal rate and any average MISO rate in lieu of any direct assignment provisions. Naturally, this provision may also work in LGE/KU's favor insofar as it incurs costs for network upgrades to its own system and can roll those costs into its zonal rate or into any average MISO rate.

For network upgrades that are not (or cannot) be directly assigned and which MISO requires to be constructed, there will be a rebuttable presumption that all upgrade costs will be allocated to all zones within the RTO.[36] The allocation of the costs will be based on a simple load ratio share formula. Thus, LGE/KU could be held responsible for a part of the costs of upgrades hundreds of miles from Kentucky from which it surely derives no benefits.

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35 The topology of the LGE/KU system and interconnections with adjacent control areas within Kentucky is such that, according to the 2002 IRP: "A limitation to transfer capability with other companies sometimes occurs when large north-south transfers are present. These north-south transfers have a significant impact on flows on the Companies' system. The ability to export KU and LG&E generation to other control areas is limited under these conditions. Additionally, the ability to dispatch generation economically within the Companies' control area may be limited under these conditions."

36 Even though it is unstated in Attachment N, the justification must be that all transmission owners and users of the MISO system benefit from the upgrade, and therefore, should pay for a portion of it.

It is difficult to determine the extent to which network upgrade costs that are not directly assigned to transmission customers will be rolled into zonal and average MISO rates that would be applied to LGE/KU transmission usage within MISO. The MISO RTEP identifies network projects that its analyses suggest could improve the efficiency of the regional dispatch under various assumptions and reduce the costs of congestion. If any of these projects were completed, it is conceivable that the costs could be rolled into MISO rates or in some way spread to all transmission owners and customers using the MISO system, especially if MISO, after the transition period, moved to a postage stamp transmission rate structure.

### 3.3.2 As a Standalone System

LGE/KU would bear all of the costs of upgrades and expansions to its system, such as those proposed in the 2002 IRP. However, it is conceivable that LGE/KU could build transmission facilities for some other entity at that other entity's expense.

### 3.3.3 As a SeTrans Member

The potential sharing of transmission costs if LGE/KU joined SeTrans is likely to be similar to that implied under MISO's Attachment N. The general policy expressed in the SeTrans OATT (also Attachment N) is that the costs of new transmission investments should be allocated to the parties that benefit from them. Attachment N distinguishes between base-funded and participant-funded investments. "Base-funded investments" are those that satisfy long-term firm commitments for network service (including deliverability of designated network resources) and long-term firm point-to-point service (including transactions that exit or go through the SeTrans). "Participant funded investments" are those that meet the needs of particular parties and that are directly funded by those parties (referred to as direct assignment in MISO).[37] SeTrans may determine that the costs of a base-funded project will be allocated to multiple pricing zones.

The situation whereby the costs of a transmission expansion project are rolled into the rates for all zones would be even more problematic for LGE/KU as a SeTrans member than as a MISO member, since there would arguably be few projects in the contiguous SeTrans footprint that would result in significant benefits for LGE/KU or its native load. At least in some cases within MISO, a transmission project whose costs are allocated to all zones may well have some benefit for LGE/KU in terms of lower dispatch costs or improved market access.

### 3.3.4 Within a Kentucky ISO

Because a Kentucky ISO does not yet exist and is not even in the planning stage, it is difficult to accurately surmise how costs of transmission investments may be allocated.

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[37] See "Open Access Transmission Tariff for the SeTrans Independent System Administrator," Text Mailed 6-30-2003, Attachment N, Section 9, May 29, 2003 Draft ("SeTrans OATT").

### 3.4 Access to Transmission Service

LGE/KU's access to transmission depends now and will continue to depend on whether it has been given an opportunity to pay either a market price or a regulated price for rights to capacity on interconnections between its territory and adjacent territories or on paths within RTOs or between RTOs. The question of whether it actually obtains the transmission capacity that it needs to support its trading is a function of the price relative to LGE/KU's willingness to pay. In a regime in which transmission capacity is rationed by price to those most willing to pay for it, LGE/KU in general should have access to transmission regardless of its RTO options. Conceivably situations would arise (i.e., congestion or emergencies) in which LGE/KU would not be able to obtain access to transmission at any price, in which case its transactions would be curtailed under NERC's TLR rules or under some *pro rata* curtailment rules established by an RTO to handle cases where redispatch of generation resources does not adequately relieve congestion.

LGE/KU's access to other transmission owners' systems depends upon the availability of capacity at the interconnections between LGE/KU and other regions – MISO and TVA, in particular – which is a function of regional dispatch and of whether LGE/KU has obtained firm transmission rights or, in the case of MISO, chooses to trade at a border bus (i.e., proxy bus). LGE/KU's RTO membership decision will affect LGE/KU's transmission access only to the extent that transactions are curtailed on a non-price basis rather than on a price basis. Where transactions are curtailed on a price basis, as normally occurs in a locational pricing system, LGE/KU's access would be the same regardless of its RTO membership because its willingness and ability to bid for service will depend upon factors (e.g., its generation costs and load levels) that are independent of its RTO choice. Where transactions are curtailed on a non-price basis, such as may occur under emergency conditions or as may be mandated by state laws that give priority to certain customers, LGE/KU's access may depend upon its RTO membership.

LGE/KU's access to its own transmission system depends upon the resolution of the apparent conflict between RTO rules that give non-discriminatory access to all comers and Kentucky law that gives priority to LGE/KU's native load. As a standalone utility, LGE/KU has unrestricted access to its own transmission system, subject only to the effects of congestion and loop flows that can require the redispatch of generation or, in extreme cases, load curtailment. While RTO membership can require that LGE/KU share use of its system with others, this might affect the price of access but not – under normal circumstances – its availability. Under normal circumstances, the limitations to LGE/KU's use of its own system could be the result of conditions external to the LGE/KU system, such as within the MISO system and, perhaps, TVA; and the loop flows through the LGE/KU system that arise from such conditions can occur regardless of LGE/KU's RTO option. Under emergency circumstances, however, RTO membership might require LGE/KU to curtail part of its native load instead of curtailing the transactions of others.

In summary, RTO membership, particularly in MISO, has the likely advantage of giving LGE/KU better access to transmission outside its own system on those infrequent occasions where there are emergency conditions in the RTO of which LGE/KU is a member. Being a standalone utility has the advantage of giving LGE/KU better access to its own transmission system under infrequent emergency conditions.[38]

### 3.4.1 As a MISO Member

As part of the MISO market, LGE/KU's transactions within MISO would not be tagged or put on the NERC Interchange Distribution Calculator ("IDC"), and therefore would not be subject to curtailment except under emergency conditions.[39] Self-scheduled generation would be accepted by MISO. At least in theory, MISO would use financial/economic incentives based on differences in LMPs to price use of the transmission system and hence to ration scarce transmission capacity to achieve relief of congested interfaces/paths. From the perspective of the NERC's TLR curtailment priorities, when LGE/KU's native load is served from designated resources, the transmission service priority should be firm regardless of whether LGE/KU is in MISO. In case there is a need to curtail transactions under NERC's TLR protocols, curtailments will be made on a *pro rata* basis sufficient to relieve the congestion.

### 3.4.2 As a Standalone System

If LGE/KU operates as a standalone system, all export transactions from the LGE/KU system would be tagged or put on the NERC IDC and subject to curtailment based on NERC TLR priorities.[40] However, the treatment that LGE/KU transactions would receive in cases where curtailment is necessary to relieve congestion should not differ from treatment as a member of MISO or any other RTO.

### 3.4.3 As a SeTrans Member

The major problem for LGE/KU, if it chooses to join the SeTrans RTO, is that it does not have direct transmission access to the SeTrans grid. Reservations of firm transmission capacity will have to be secured through TVA's system. Thus, to the extent that there are limits on capacity that can be reserved through TVA, the lack of firm capacity will hamper LGE/KU's ability to trade with other SeTrans RTO participants.

Assuming that LGE/KU becomes a member of the SeTrans RTO, SeTrans will follow similar curtailment procedures as will be applied in MISO. SeTrans will operate or administer a set of Day Two markets, will price transmission use according to differences in locational prices, and will offer FTRs to hedge against locational (i.e., congestion) price risk.[41]

As in the MISO RTO, should the need arise within SeTrans to curtail transactions, curtailments will be made on a non-discriminatory basis with regard to all transactions that effectively relieve the constraint. If necessary, SeTrans may decide to implement curtailments based on NERC's

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38 This will be true so long as native load priority is in effect, as it is currently under Order No. 2000.

39 Communication from L. Monday, Transmission Group.

40 Communication from L. Monday, Transmission Group.

41 SeTrans ISA, "Draft Open Access Transmission Tariff: Attachment V, Sheet No. 331," http://www.setransgrid.com/organic.htm, May 1, 2003, at 331.

TLR procedures. If several transactions require curtailment, SeTrans will curtail service to network customers and transmission customers taking firm point-to-point transmission service on a comparable basis.[42] Non-firm point-to-point service will be always subordinate to firm point-to-point service. Most of these provisions would not be expected to affect LGE/KU because of the lack of direct connections to SeTrans.

### 3.4.4 Within a Kentucky ISO

As a member of a Kentucky ISO, LGE/KU naturally would have access to its own transmission system subject to physical limits of that system and the effects of regional power flows on those limits. LGE/KU's transactions into or through MISO would be treated on a non-discriminatory basis given their curtailment priority. If MISO found that curtailment was necessary to relieve congestion, along with redispatch, it states that it would curtail network customers and firm PTP customers on a comparable basis. Kentucky law requires that LGE/KU's native load receive curtailment preference regardless of whether LGE/KU remains a MISO member: this directly conflicts with the MISO tariff. If LGE/KU were not a member of MISO or an RTO with a similar curtailment policy, LGE/KU would be better positioned to comply with Kentucky law.[43]

### 3.4.5 Transmission Rights Values: Obligations vs. Options

LGE/KU's transmission rights as an RTO participant may be of lower value to LGE/KU if they are in the form of *obligations* rather than *options*. A market participant with an FTR *obligation* receives money when congestion is in the direction of their rights (which is generally from resources to loads) and pays money when congestion is "backwards", that is, in the opposite direction. A market participant with an FTR *option* also receives money when congestion is in the direction of their rights, but does not pay money congestion is in the opposite direction. An FTR option is thus more valuable to market participants than an FTR obligation with otherwise identical terms because the option does not require payment when congestion is in the direction opposite to that of their rights.[44]

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42 SeTrans ISA, "OATT vs. MISO OATT," http://www.setransgrid.com/organic.htm, June 30, 2003, at 59-60.

43 Communication from Brunner, MRMD Group.

44 Contrary to a widely held misperception, FTR obligations are less risky than FTR options in the sense that the former leads to greater certainty in the profits of the FTR owner. For example, suppose that a particular market participant has a 100 MW generator that produces power at $20/MWh at node A, a 100 MW load at node B, and a 100 MW FTR obligation from A to B. If the locational prices at A and B are respectively $30/MWh and $34/MWh, the participant's cost of serving load will be $2,000: the cost of power production is $2,000 (100 x $20); the congestion cost is $400 (100 x ($34-$30)); FTR revenue is $400 (100 x ($34-$30)); and total cost is $2,000 = $2,000 + $400 – $400. If the locational prices at A and B are instead $30/MWh and $27/MWh, so that congestion backwards, the participant's cost of serving load will again be $2,000: the cost of power production is $2,000 (100 x $20); congestion revenue is $300 (100 x ($27-$30)); the FTR payment is $300 (100 x ($27-$30)); and total cost is $2,000 = $2,000 – $300 + $300. FTR obligations thus lead to a high degree of certainty in costs and profits.

Consider the same example applied to an FTR option. If the locational prices at A and B are respectively $30/MWh and $34/MWh, the participant's cost of serving load is again $2,000. But if the locational prices at A and B are instead $30/MWh and $27/MWh, so that congestion is backwards, the participant's cost of serving load is only $1,700: the cost of power production is $2,000 (100 x $20); congestion revenue is $300 (100 x ($27-$30)); the FTR

## 3.5 Allocation of Transmission Rights

For transmission rights that hedge against congestion cost risks in serving LGE/KU's native load from its own generation over its own transmission system, the standalone and SeTrans options appear to be most favorable. For transmission rights over other transmission owners' systems, the MISO option appears to be most favorable.

Pending federal energy legislation may protect LGE/KU against a loss of transmission rights relative to those that it now enjoys. The draft Energy Policy Act of 2003 (HR 6, Section 16023), provides priority in transmission service to any "party that owns interstate transmission facilities (or holds a contract of service agreement for firm transmission service used to purchase or deliver power) to meet a 'service obligation' or fulfill a wholesale contract existing on March 28, 2003."[45] This priority would take precedence over other parties' use of the transmission system, and would not constitute an "undue discrimination or preference" under the Federal Power Act (Sec. 7023(e)).[46] If passed into law, such a provision could reduce LGE/KU's cost of RTO participation when the regional grid becomes congested.

### 3.5.1 As a MISO Member

As a member of MISO, LGE/KU will be allocated a share of MISO's financial transmission rights ("FTRs"). FTRs will be available as flowgate rights ("FGRs")[47] and point-to-point FTRs ("PTP FTRs"). The latter will be available in the form of both options and obligations.[48]

LGE/KU could acquire FTRs through (1) an initial allocation of PTP FTRs, (2) FTR auctions, (3) the purchase of new transmission service, (4) the FTR secondary market, and (5) the allocation of FTRs in connection with transmission expansion or upgrades.

MISO will initially allocate PTP FTRs to all parties who have pre-Day Two entitlements to transmission service and who pay a charge for the embedded cost of the transmission grid. To the extent that the transfer capability of the existing transmission grid is sufficient to support

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payment is zero; and total cost is $1,700 = $2,000 – $300. FTR options thus lead to uncertain costs and profits by creating the possibility of windfall gains when congestion is backwards.

The valid criticism of obligations is not that they are risky relative to options – precisely the opposite is true – but is instead that they require participants to give back to the power system the windfall gains that they sometimes enjoy under their existing transmission contracts. For LGE/KU, this loss of windfalls would apply only to transmission service purchased from other transmission owners, not to service over LGE/KU's own system, as the former may be implicit options while the latter are implicit obligations.

45 108th Congress, 1st Session, H.R. 6, "An Act to enhance energy conservation and research and development, to provide for security and diversity in the energy supply for the American people, and for other purposes," Short Title: "Energy Policy Act of 2003," Title VI, Electricity Title, Subtitle B—Transmission Operation, Sec. 16023, Native Load ("HR6").

46 A "savings clause" for some actions at certain independent transmission organizations was adopted at full committee, the effect of which is unclear. The affected "ISO's" are PJM, New York ISO, New England ISO, Midwest ISO, and the California ISO.

47 Flowgate rights will not be offered initially.

48 See Midwest Independent Transmission System Operator, "Midwest Market Initiative, Market Protocols, Version 1.0," June 12, 2003.

FTRs in excess of those initially allocated, the additional transmission capability will be auctioned in the form of additional PTP FTRs and FGRs.

No later than two years from the date that FTRs assigned through the initial allocation process first become valid, transmission customers may convert their initial allocation of PTP FTRs into an allocation of point-to-point auction revenue rights ("ARRs"). ARRs are defined identically to FTRs, in terms of megawatts, source and sink, but are settled based on the clearing prices in the FTR auction rather than being paid a share of the day-ahead transmission congestion charges. The intention is to have a transition period before a voluntary auction of transmission rights is implemented.

The initial allocation of FTRs will be assigned to loads, which will generally mean to the transmission customers who are currently taking transmission service on behalf of ultimate retail load. The initial allocation of FTRs will be made in terms of PTP FTRs and may consist of PTP FTR Options, PTP FTR Obligations, or a combination of PTP FTR Options and PTP FTR Obligations. The initial allocation of FTRs will be simultaneously feasible within a security-constrained power flow, taking into consideration any unconverted pre-OATT existing entitlements and an appropriate representation of unscheduled loop flow from external control areas. The feasibility test is necessary to avoid over-allocating FTRs, which could lead to a situation in which the congestion charges collected by MISO in the day-ahead and real-time markets are not sufficient to fund the transmission congestion credit target allocations owed to holders of FTRs (i.e., there would be a revenue shortfall). In the case that not all candidate FTRs are simultaneously feasible, some pro-rationing will be required to identify a simultaneously feasible initial allocation of FTRs.

At least ninety days prior to the beginning of each year, market participants will provide MISO a prioritized list of their FTR requests for the upcoming year. FTRs will be allocated to entities based on their historic use of the MISO footprint. At least sixty days prior to the beginning of the year, MISO will post on its publicly accessible website the resulting annual schedule of FTRs.

From MISO's description of the initial FTR allocation process and the process for determining FTR allocation in subsequent years, it is difficult to infer precisely what LGE/KU's initial FTR allocation will be, and it is more difficult for the years 2005-2010, since there is no "historical" record to build upon. It is quite possible that, under a simultaneous feasibility constraint, LGE/KU could receive an allocation of PTP FTRs that is smaller than its existing physical rights. It does not seem reasonable to assume that the FTR allocation could be greater than the existing physical rights, so that something less than 100% of the current entitlement is likely.

### 3.5.2 As a Standalone System

LGE/KU would retain all the rights it currently has to its own system for service to native load customers. With regard to transmission rights on other systems, it would be necessary to purchase firm PTP service from TVA or purchase FTRs in MISO through a secondary market auction or risk exposure to congestion costs in the day-ahead and real-time markets.

### 3.5.3 As a SeTrans Member

Relative to the MISO base case option, the SeTrans option may promise a more favorable allocation of transmission rights to LGE/KU to serve its native load customers. According to the SeTrans OATT, the SeTrans ISA will allocate long-term FTRs that reflect members' full existing capacity rights as of Day Two implementation. The purpose of this long-term allocation is to ensure that those who are obligated to continue to pay the embedded cost of the transmission grid continue to receive the economic value of the transmission grid under the SeTrans structure. The general allocation approach will attempt to match as closely as possible the assignment of FTRs with both the current obligations of parties to support the embedded cost obligations of the transmission system, as well as those parties' current firm usage of the transmission system. This will allow native load customers to reserve FTRs for future reliability needs, consistent with their ability to do so today. The long-term allocation will form the basis for annual nominations of FTRs by firm customers. FTRs that are not nominated in a given year will be auctioned in a residual auction. The long-term allocation will provide the revenue allocation methodology for these auctions. This allocation process will also facilitate the determination of incremental FTRs associated with future system expansions, because it will help clarify which FTRs are associated with pre-existing system capacity and which FTRs are truly created by expansions.[49]

### 3.5.3 Within a Kentucky ISO

It is difficult to say what the allocation of transmission rights would be within a Kentucky ISO, but it would be expected that LGE/KU would retain all the rights it currently has to its own system for service to native load customers. With regard to transmission rights on other systems, it would be necessary to purchase firm PTP service from TVA or purchase FTRs in MISO through a secondary market auction or risk exposure to congestion costs in the day-ahead and real-time markets.

## 3.6 Transmission Revenues

Regardless of the RTO option chosen, transmission revenues for LGE/KU arise in general from providing three types of service: network service, point-to-point service, and ancillary services. Point-to-point service (firm or non-firm) can be provided to customers in four forms in relation to the LGE/KU control area: drive-in, drive-out, drive-through and drive-within. Ancillary services are provided to support both network integration service and point-to-point services.[50] LGE/KU is not expected to provide network integration service to any RTO market participant but itself. Regardless of the RTO option, transmission revenues from point-to-point service for others, including LGE/KU's own trading arm, are typically used to reduce the revenue requirement borne by native load customers.

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49 The incremental FTRs created by Base Funded projects will be made available to Transmission Customers in accordance with Attachment Y, Appendix A. Parties that fund an upgrade will receive the net FTRs created by that upgrade, if any, under rules specified in Attachment Y, Appendix A of the SeTrans OATT.

50 The six ancillary services are: scheduling, system control and dispatch; reactive supply and voltage control, regulation and frequency response service, energy imbalance and inadvertent interchange, spinning reserves, and supplemental reserves.

The transmission revenues will vary across the options, although it is difficult to quantify the differences, in part because the revenue distribution rules have not been clarified completely in the case of the MISO and SeTrans options and are simply non-existent in the case of the Kentucky ISO option. Regardless of the option, LGE/KU could anticipate virtually the same revenue stream from the provision of network service to its native load customers. However, LGE/KU's portion of the transmission revenues received by MISO and SeTrans RTOs depends on the revenue distribution rules. The standalone system option may result in slightly lower transmission revenues than the MISO and SeTrans RTO options if FERC does not permit LGE/KU to charge for drive-through and drive-out point-to-point service. This possibility arises from the FERC's recent order eliminating regional through and out rates between MISO and PJM.[51]

FERC's current policy of rewarding utilities such as LGE/KU with a higher return on equity for joining RTOs (or ISOs) would apply for all options except the standalone system. This higher return (50 basis points) has been applied to transmission facilities used exclusively for unbundled wholesale transmission. This increase is applied to less than 10% of LGE/KU's rate base. Thus, the amount that will be foregone by LGE/KU if it were to withdraw from MISO is *de minimis.*

### 3.6.1 As a MISO Member

As a MISO member, LGE/KU will get revenue from both "regular" and "transitional" sources. The "regular" sources are as follows:

- *Grandfathered transmission contracts.* Revenue received by LGE/KU under transmission service contracts in place before the creation of MISO will be grandfathered. This means that LGE/KU will continue to receive these revenues directly from the customers, at least until such time as the contracts expire or are vacated by either party. LGE/KU projects that this revenue will be a relatively constant $6.8 million during the study period. Note that the revenue from grandfathered contracts would be received by LGE/KU regardless of its membership in MISO. The difference between grandfathered revenues as a MISO member and grandfathered revenues in the standalone system alternative was estimated to be $1 million per year, primarily due to the application of lower Schedule 1 and Schedule 9 rates. The rates for these services in the standalone system alternative are lower because LGE/KU's rates before it joined MISO were lower than MISO's rates for these services.
- *Transmission service revenue.* During a transition period that ends in 2008, LGE/KU will receive revenue from providing point-to-point service that will be based on zonal rates. After the transition period, monthly transmission service revenue will be based on LGE/KU's proportionate share of the total revenue requirement of all MISO transmission owners, subject to annual true-ups to account for shortfalls and overages.

The "transitional" revenue sources are as follows:

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[51] *See* Federal Energy Regulatory Commission, "Midwest Independent System Operator, et al., Order on Initial Decision," Docket Nos. EL02-111-000 and EL03-212-000, Issued July 23, 2003 ("EL02-111 Order").

- *Lost regional through and out rates ("RTOR") revenue recovery.* Under the MISO Transmission Owners Agreement, LGE/KU's relative share of "lost revenues" resulting from the elimination of pancaked rates (what would have been received under RTOR Schedule 14 of the MISO OATT) within the MISO region was estimated to be 17.98 % of the $115,706,000 RTOR revenues for all MISO members for the 2001 test year, or $20,803,949.[52] However, Schedule 14 charges are to be eliminated by November 1, 2003 per FERC order, but a two-year transition permits recovery of "lost revenues" subject to adjustments for known and measurable changes in light of a forward looking approach.[53] Thus, LGE/KU can expect to receive a portion of the amount distributed by MISO monthly during a two-year transition period that would begin November 1, 2003 and end October 31, 2005. The actual amount of "lost revenues" that LGE/KU receives will be based half on the LGE/KU's relative share of total lost revenues and half on the relative flows on the LGE/KU's transmission system for drive-through and drive-out point-to-point transmission service transactions. LGE/KU estimates that the "lost revenues" recovered through this mechanism will be in the neighborhood of $1.5 million per year for the period 2004 to 2006.[54]
- *Sub-regional rate adjustment (SRA) revenues.* As part of the agreement to form MISO that eliminated pancaked rates within the RTO footprint, LGE/KU would be collecting lost transmission revenues for a three-year transition period[55] through a sub-regional rate adjustment (SRA) mechanism. The SRA is a surcharge to the zonal transmission rates for transmission service within the MISO footprint. Each transmission customer taking network integration transmission service or point-to-point transmission service under the MISO OATT is expected to pay the SRA in accordance with the rates it would pay under Schedules 7, 8 or 9, as applicable. The estimated revenue generated by the SRA has been included in our discussion of the lost RTOR revenues.
- *Super-regional rate adjustment revenues.* The creation of MISO involved a settlement agreement for additional lost RTOR revenues between the existing MISO members and particular former Alliance RTO members (FirstEnergy, NIPSCO, and Ameren, referred to collectively as the GridAmerica Companies). Under this agreement, lost through and out revenues are to be collected under Schedule 13 of the MISO OATT.[56] The agreement created an adjustment to rates for a transition period, called the super-regional rate adjustment mechanism.[57] As part of that settlement, LGE/KU would receive during the transition period an amount originally estimated as its relative share of such revenues, about $1.35 million. The actual recovery is expected to be less and has been included in the estimate of lost RTOR revenues stated above.

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52 Midwest Independent Transmission System Operator, FERC Electric Tariff, First Revised Rate Schedule No. 1, Appendix C-3, Attachment 1, Transmission Owners' Relative Share of Lost Revenues, February 1, 2002.

53 *See* EL02-111.

54 This estimate includes revenues recovered through the SRA mechanism as described in the next subsection.

55 The period begins with the start of service under Schedule 18 of the MISO OATT.

56 The March 21, 2001 settlement filed in FERC Docket No. ER01-123-000, *et al.* and accepted by FERC on May 8, 2001. Illinois Power Co., 95 FERC ¶ 61,183 (2001).

57 Essentially an adder to the MISO tariff.

### 3.6.2 As a Standalone System

It is extremely difficult to say what, if any, change there would be in LGE/KU's transmission revenues received from customers besides LGE/KU's merchant division. Transmission revenues depend on use, which in turn, depends on the prices for access and use. The price for use will depend on MISO's bid-based, security constrained economic dispatch and the differential between power prices within regions in MISO or between power prices in non-MISO regions adjacent to Kentucky (e.g., TVA) and power prices in MISO. For example, LGE/KU might well be a desirable path when, for example, the LMPs in western MISO (e.g., Ameren) significantly differ from LMPs in the eastern side of MISO (e.g., Cinergy).[58]

Related to transmission revenues is the issue of the return on equity for transmission facilities engaged in providing wholesale service. LGE/KU may not be recipient of higher rates of return on equity if it is not a member of an RTO or ISO. FERC has awarded LGE/KU a higher return on equity for its wholesale facilities, but perhaps FERC would reconsider this incentive if LGE/KU exited from MISO.[59]

- *Revenue from Grandfathered Transmission Contracts.* Grandfathered transmission contract revenues are assumed to be about $6.8 million in 2004, but would be expected to decline to about $5.8 million over the period 2005-2010 because any new FERC-approved Schedule 1 and 9 rates for LGE/KU as a standalone system would be lower than the Schedule 1 and 9 rates under the MISO OATT.[60] Typically, grandfathered contract revenues are based on contracts that do not fall under the MISO Tariff. However, grandfathered contracts allow LGE/KU to charge Schedule 1 and 9 rates to the East Kentucky Power Cooperative and TVA under the MISO OATT, with a FERC-approved ROE of 12.88%. If LGE/KU moves to a standalone system, it will have to seek approval from FERC for a new OATT; and Schedule 1 and 9 rates are expected to be lower by an amount that will reduce revenues by about $1 million per year.
- *Transmission service revenue.* Given the revenue requirement that already exists for LGE/KU, we would not expect there to be any significant change in transmission revenues, as there would be no change anticipated in the rates for network integration service or point-to-point service.
- *OASIS.* The economies of scale and scope may be significant for centralized operations and operation of an OASIS. Under the standalone system scenario, OASIS revenues are projected to be $0.10 million per year for the period 2005-2010. There would be no OASIS revenue under the MISO scenario. The expected cost for LGE/KU to manage an OASIS site is approximately $0.42 million per year, whereas LGE/KU's share of the operational costs of the MISO OASIS site, even if MISO's OASIS costs were three times as much, would be only $69 thousand per year.[61] Therefore, as a standalone system,

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58 Communication from Brunner, MRMD Group.

59 Again, we have not taken into account any actions that FERC might take in considering incremental costs and savings of one alternative versus another. For example, we have not evaluated the impact of a FERC revocation of LGE/KU's market-based rate authority.

60 MISO's Schedule 1 rate is ten times higher than LGE/KU's Schedule 1 rate before it joined MISO.

61 Assuming LGE/KU was responsible for roughly 5.5% of MISO's annual operational costs.

LGE/KU would have a net increase in operations costs of roughly $0.25 million per year for the OASIS.[62]

- *Regional Through and Out Rates ("RTOR") Revenue.* There will be no lost RTOR revenue so long as LGE/KU as a standalone system is permitted by FERC to have a RTOR. However, this is big assumption to make given the FERC's recent order that eliminated the RTORs between MISO and PJM.[63] Even if the KPSC finds that it is in the public interest to order LGE/KU out of MISO in 2004, LGE/KU will still need to obtain FERC approval, and FERC may be in a position to require elimination of RTORs as a condition. In addition, the recent FERC order in the EL02-111 case requires any utility seeking "lost revenues" to file for recovery under Section 205 (of the FPA), and for those utilities that are not members of an RTO to have a reasonableness review of their rates under Section 206. This may subject the companies' rates to greater scrutiny than under the MISO base case.

#### 3.6.3 As a SeTrans Member

Transmission revenues associated with provision of Schedule 1-9 services under SeTrans would depend on how much service is provided, the billing determinants defined under the SeTrans OATT Schedules and the revenue allocation mechanisms defined under the SeTrans OATT.

- *Revenue from Grandfathered Transmission Contracts.* Revenue from grandfathered transmission contracts are assumed to be the same as in the MISO base case and the standalone system option.
- *Transmission Service Revenue.* No zonal rates have been established for SeTrans RTO, but it would be expected that LGE/KU's zonal rates would be the same under the SeTrans option as under the MISO option, since it would be LGE/KU's revenue requirement that would be the basis for setting the zonal rate for the LGE/KU control area.
- *Regional Through and Out Rates ("RTOR") Revenue.* To join SeTrans, LGE/KU would agree to eliminate RTORs applied to transmission service within the RTO footprint. However, since there is no direct electrical interconnection with SeTrans, LGE/KU provides very little transmission service to the other potential members of SeTrans, therefore it would not likely be giving up any transmission revenue. Assuming that through and out rates between SeTrans and MISO were not eliminated, as they have been between MISO and PJM, LGE/KU would be looking at virtually the same revenue for transactions driving through its control area to SeTrans (or to TVA) whether it was member of MISO or SeTrans. As a border transmission owner in MISO, LGE/KU would apply a drive-out RTOR to any transaction leaving MISO for TVA or SeTrans that used LGE/KU's system. As a border transmission owner in SeTrans, LGE/KU would apply a drive-through RTOR to any transaction with source in MISO to sink in TVA that used

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62 This net increase is based on analysis conducted by the LGE/KU Transmission Group of all functions of running a standalone system that are currently being done by MISO. The expected costs of the OASIS are broken out for purposes of discussion and illustration only.

63 *See* EL02-111.

the LGE/KU system. While the RTOR rates could be different in MISO and SeTrans, there is no reason to believe that they would be significantly different. In addition, as a border member of SeTrans, LGE/KU may also receive revenue from transactions sourced in TVA that sink in MISO. However, the direction of flows historically has been north to south, rather than south to north, so that it is not likely that LGE/KU would see

#### 3.6.4 Within a Kentucky ISO

Under the Kentucky ISO option, we expect the transmission revenue sources would continue as under the standalone system option.

- *Revenue from Grandfathered Transmission Contracts.* We assume that revenue would continue to be recovered from grandfathered contracts. Hence, there would not be any change expected from the base case scenario except to the extent that the Schedule 1 and 9 rates change under the OATT administered by the Kentucky ISO as they are expected to change under the standalone system option.
- *Transmission Service Revenue.* It is expected that zonal rates (e.g., for network service) would match the zonal rates currently in place in MISO, since it would be LGE/KU's revenue requirement that would be the basis for setting the zonal rate for the LGE/KU control area.
- *Regional Through and Out Rates ("RTOR") Revenue.* There will be no lost RTOR revenue so long as LGE/KU the Kentucky ISO was permitted by FERC to have a RTOR. Again, this is big assumption to make.

### 3.7 Payments/Costs for Transmission Service

Transmission service costs (or payments) can be separated into three categories: transmission usage costs, transmission access costs and ancillary service costs. Transmission usage costs are charges for congestion and losses and can be priced separately or in LMP based systems will be priced together (the cost of losses and congestion are implicit in nodal price differences). Transmission access costs are charges to recover the fixed costs of the transmission facilities (i.e., capital costs plus a return on investment). When LGE/KU purchases FTRs, it is paying the expected cost of future congestion charges. Ancillary services charges will be paid by the trading arm to LGE/KU for services provided to the border, and will be paid to MISO or TVA for services provided outside of the LGE/KU service territory.

Thus, for all RTO options, LGE/KU's transmission service costs will consist of access and usage charges (or expected future usage charges) and ancillary service charges. LGE/KU's native load customers will pay LGE/KU's zonal network integration service rate for access. LGE/KU's marketing division will pay LGE/KU for point-to-point (firm or non-form) transmission service to any border bus between LGE/KU and MISO or TVA.[64] As a member of MISO, LGE/KU will pay for point-to-point service to cover trades within or through MISO (and after November 1, within or through MISO and PJM) and TVA.

[64] The revenues received by LGE/KU from its marketing division for the purchased of point-to-point service are used to reduce the charges to native load customers.

In addition, there are the costs of transmission use (congestion and losses), which under the Day Two market, will be based on nodal price differences within MISO (and PJM) corresponding to a point-to-point off-system trades. LGE/KU may purchase FTRs to hedge the costs of congestion (and losses). If LGE/KU were to engage in off-system trading beyond a MISO border proxy bus, it would be exposed to congestion costs under all RTO options. It would therefore have to buy FTRs in a secondary FTR market auction or risk congestion costs in the real-time market. We have not estimated the costs of those FTRs.

### 3.7.1 As a MISO Member

LGE/KU's native load customers will pay for network integration service (i.e., Schedule 9). The majority of Schedules 1 through 6 charges associated with the provision of ancillary services for network service will be borne by its native load customers, since these services will be self-supplied by LGE/KU.[65]

If the merchant division of the company wants to sell to another network service customer within MISO (and to PJM after November 1, 2003), once they pay the LGE/KU zonal access charge for point-to-point service, they can get the power to the customer without having to pay any additional transmission access charges (for example, the MISO customer could use its network integration service to import the power).

Congestion within the MISO system will at times require LGE/KU generation to be redispatched. Some of the redispatch costs will be paid by LGE/KU's native load customers who are taking network integration service. The rest will be paid either by the companies' trading arm or by other point-to-point transmission customers driving into or through the LGE/KU system. The cost of redispatching the LGE/KU system because of congestion in MISO is projected to be \$1.2 million per year for the period 2005-2010.[66] The LGE/KU's share of the total cost of congestion in MISO on an annual basis is estimated to be \$16 million. If LGE/KU is allocated sufficient FTRs to hedge 80% of this, which is what the Companies expect under an FTR allocation that satisfies a feasibility constraint, the cost of the 20% unhedged would be \$3.2 million, or an increase of about \$2.0 million per year.

No estimates have been made for the costs of ancillary services provided to support off-system trades.

LGE/KU has one of the lower cost transmission systems within the MISO footprint one that yields rates that are lower than the average rate in MISO. Therefore, if MISO were to move to a postage stamp rate (i.e., a single region-wide average rate) for transmission access in the period 2008-2010, LGE/KU's customers could pay more for transmission access than they are currently paying. No estimate has been developed for the increase in the cost of transmission access for

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[65] Schedule 1 through Schedule 6 are rates for ancillary services under the OATT, all of which are self-supplied by LGE/KU. Schedule 7 sets rates for long-term firm and short-term firm point-to-point service. Schedule 8 sets rates for non-firm point-to-point service. Schedule 9 sets rates for network integration service.

[66] These estimates are based on historical costs during the period before LGE/KU became a member of MISO. The cost could be higher or lower if LGE/KU depending on the pattern of power flows within MISO over the next seven years and the extent of transmission expansion to relieve bottlenecks within the MISO region.

network integration service within the LGE/KU territory if MISO were to adopt postage stamp access pricing.

### 3.7.2 As a Standalone System

If LGE/KU were to operate as a standalone system, Schedule 1 through 6 (ancillary services) and Schedule 9 costs (network integration service) will still be borne by LGE/KU's native load customers, since these services would be self-supplied. However, if LGE/KU operates as a standalone system, any purchases of energy for native load from within MISO would still pay rates based on MISO Schedules 1, 2, 7 or 8, 10, 14, 16 and 17 and Attachment M (i.e., losses).

With LGE/KU outside MISO, LGE/KU's marketing division would have to reserve and schedule transmission through the LGE/KU's OASIS to get to the LGE/KU border with MISO and would pay an access charge for point-to-point service. However, it would not necessarily have to purchase additional transmission service to deliver within MISO.[67] A supplier to the MISO market, such as LGE/KU, need not purchase transmission service in the Day Two market: external market participants have the option to sell and purchase at an external proxy bus. The recently filed MISO Day Two OATT does not state a requirement that external demand bids be accompanied by an "out-of-MISO" wheel. In addition, LGE/KU has direct links to both MISO and PJM and thereby avoids transmission pancakes even as a stand-alone system. Therefore, it is possible that LGE/KU could avoid the point-to-point access charges by trading at a border bus. Regardless of whether the trading arm purchased PTP service within MISO or chose to buy and sell at the border bus, it will still be subject to congestion charges and would either be buying FTRs to hedge those costs or paying ex post real-time market congestion costs.

If the trading arm of the company were to purchase PTP transmission service, the projected cost of Schedule 7 or Schedule 8 service for off-system trades in MISO is projected to average roughly $1.0 million per year for the study period.[68]

For LGE/KU to operate a standalone system, the cost of dispatching its system to reduce flows on internal flowgates that result from the MISO regional dispatch is projected to equal about $1.2 million per year for 2004-2010.[69] The LGE/KU's share of the total cost of congestion in MISO on an annual basis is estimated to be $16 million. If LGE/KU is allocated sufficient FTRs to hedge 80% of this, which is what the Companies expect under an FTR allocation that satisfies a feasibility constraint, the cost of the 20% unhedged would be $3.2 million, or an increase of about $2.0 million per year.

We have not estimated the costs of ancillary services that would be provided to support off-system trades. Ancillary services provided from within the LGE/KU system to support off-system trades are expected to be the same whether the companies are members of MISO or operate as a standalone system.

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67 Communication from L Monday, Transmission Group.

68 This is based on a projection of off-system purchases (MWh) multiplied by the short-term firm point-to-point rate.

69 These estimates are based on historical costs during the period before LGE/KU became a member of MISO. The cost could be higher or lower if LGE/KU depending on the pattern of power flows within MISO over the next seven years and the extent of transmission expansion to relieve bottlenecks within the MISO region.

### 3.7.3 As a SeTrans Member

The costs of Schedule 1 through 6 charges will not likely vary from the base case insofar as LGE/KU will self-supply these services to native load. There is not expected to be any change in the costs of network integration services that native load customers would pay, since there would be no change in the revenue requirement.

Since LGE/KU has no direct interconnection with SeTrans, it would have to reserve either firm point-to-point service (Schedule 7) or non-firm point-to-point service (Schedule 8) through TVA. Under Schedules 7 and 8, LGE/KU would be paying TVA the monthly service charge of $1.586/kW-month of reserved capacity.[70] No estimate has been made of the total cost of these services for trades between LGE/KU and the rest of SeTrans.

LGE/KU would have to pay a system-wide RTOR rate for firm or non-firm point-to-point service to make off-system trades outside of SeTrans, either to MISO, PJM or another non-SeTrans control area (e.g., EKPC). However, as a border utility in SeTrans, it would be expected that most of this payment would be recovered by the companies. As indicated below, this would impede LGE/KU's marketing of residual power relative to the MISO scenario to the extent that this system-wide rate is higher than corresponding rates LGE/KU generation marketing must pay in MISO. And to the extent that this reduces off-system sales and reduces profits, it could reduce the opportunities that LGE/KU native load customers to benefit from such sales through the earnings sharing mechanism ("EMS"). The non-firm point-to-point system-wide RTOR rate will be at least equal to the weighted average of the participating transmission owners' zonal rates and will not exceed the highest zonal rate.

In addition, there is a major concern with the SeTrans revenue distribution method in connection with the calculation of lost revenues and the distribution of the RTOR revenues. LGE/KU would not have any lost RTOR revenue because historically little trading has taken place between LGE/KU and the other members of SeTrans, so there would be nothing to recover through SeTrans RTOR distribution. It is conceivable that LGE/KU would experience significant RTOR costs because most of its trading business is with TVA, EKPC, Big Rivers, PJM and MISO members. If it traded with non-SeTrans entities, it may have to pay SeTrans RTORs, unless those were waived. The SeTrans RTOR revenues would go to first recover lost intra-regional revenues over a 10-year period, hence LGE/KU might expect to get very little of this returned. In contrast LGE/KU would recover at least some of it lost revenues if it were in MISO.

It is uncertain whether SeTrans would waive the RTOR costs for trades sinking in MISO and PJM? High RTOR costs will impede LGE/KU's ability to trade with other northern RTOs. Will MISO and SeTrans sign a coordination agreement that will reimburse LGE/KU's redispatch costs? If there is not a coordinating agreement between SeTrans and MISO for reimbursement of redispatch costs, then LGE/KU will have to pay its own redispatch costs through the market in the form of high LMP prices.[71]

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70 Tennessee Valley Authority, "Transmission Service Guidelines, 2003 Edition, Schedules 7 and 8," http://www.tva.gov/power/xmission_use.htm, 2003, at 59-60.

71 Communication from L. Monday, Transmission Group.

### 3.8 Reliability and Planning Benefits

LGE/KU has not suffered a transmission-level outage in over a decade.[72] It is not obvious why, as a practical matter, LGE/KU's being a standalone utility would have any result other than a continuation of this record. It is also not obvious why, as a practical matter, membership in any RTO could improve upon this record of success. In theory, participation in a large RTO might marginally improve future reliability if that RTO, like MISO, is strongly interconnected with LGE/KU; but participation in RTOs with weak or non-existent interconnections with LGE/KU, like a Kentucky ISO or SeTrans, cannot be expected to improve future reliability even in theory.

In light of the blackout that occurred August 14, 2003, there are two questions to be raised with regard to reliability. Will membership in an RTO or ISO that permits LGE/KU to benefit from the effects on reliability of wide-area coordination and trading rules lower the probability of a transmission-level outage affecting LGE/KU relative to its operating a standalone system? If so, will the decrement in the probability result in a decrease in the expected cost of a transmission-level outage large enough to offset some or all of the costs of RTO membership (e.g., Schedule 10, 16 and 17 charges)?

#### 3.8.1 As a MISO Member

Some aspects of the consolidation of dispatch and transmission control under the MISO option could conceivably reduce the probability of a transmission-level outage affecting LGE/KU's system. However, it is quite possible that nearly all of the benefit of that could still be captured through appropriate coordination agreements with MISO and investments in system upgrades that improved both interregional coordination and LGE/KU's real-time control of its own system vis-à-vis the broader regional grid.

In emergency situations, probably the most important aspect of reliability management arises from the ability of the reliability authority to take steps to directly address a problem in a timely fashion, which means that the reliability authority has the means to direct actions of buyers and sellers (load-serving entities or loads and generators) to correct a problem on the system. This may mean that reliability rules need to be made mandatory and that civil penalties should be imposed for rules violations for disobeying orders.

While command and control of the reliability authority may be an essential tool, another complementary way to shape market participants' behavior when events threaten the system is to ensure that buyers and sellers pay the marginal cost of their transmission use.[73] If market participants are required to pay the marginal cost of their transmission use, then at times of system stress, high transmission congestion prices can provide an economic incentive for transmission customers to self-ration transmission use. This self-rationing could conceivably

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[72] However, the ECAR region did experience rather severe north-south power transfer problems on July 22, 1993 that could have resulted in large scale, cascading power outages in the ECAR region, including the Kentucky Utilities' service territory. See East Central Area Reliability Coordination Agreement, "Assessment of System Conditions in ECAR on July 22, 1993," August 1994.

[73] The discussion in the text mimics the argument presented by Fernando L. Alvarado and Rajesh Rajamaran, "The 2003 Blackout: Did the System Operator Have Enough Power?" http://www.lrca.com/NewReleases/Blackout_Investigation.pdf, August 28, 2003.

improve reliability by relieving system stress before it reaches the stage of cascading outages of the type that affected so much of the Eastern Interconnection on August 14th. If MISO's transmission pricing on that date had included charges for transmission use that reflected congestion costs, these charges would have presented strong incentives to both buyers and sellers to reduce transactions that used the congested facilities. In the case of the August 14th blackout, certain transactions in Ohio and elsewhere that may have led up to the blackout were not facing efficient congestion charges and therefore did not have any direct economic incentive to alter their transactions to reduce transmission line overloads.[74]

Whether the responses of participants' within the Ohio system to transmission overloadings would have prevented the blackout is anyone's guess, but it could not have made matters worse. It is possible that MISO's Day Two transmission congestion pricing will contribute to greater reliability within the MISO region (and perhaps in neighboring regions). While this is a potential benefit of MISO's creation and operation of the Day Two market, the reliability benefit to LGE/KU of MISO's improved incentives for the most part should accrue to LGE/KU regardless of its MISO membership. Additional reliability benefits could arise, however, if there is close coordination between the LGE/KU system and MISO, which MISO membership might facilitate.

### 3.8.2 As a Standalone System

As a standalone utility, LGE/KU would continue to conduct its own reliability analyses and short-term and long-term generation and transmission expansion planning. MISO membership offers the difficult-to-quantify benefit of joint security coordination, outage coordination, voltage security analysis, current and next-day security analyses.

LGE/KU can staff up and invest in additional systems that would be necessary for it to perform the functions that MISO now performs, including some functions that MISO performs that LGE/KU has not heretofore performed. It is difficult to say whether this investment would translate into an increase in security or a decrease in the probability of a high-voltage transmission outage because there are too many other factors involved that determine security of the interconnected network and that contribute to the probability of event on the network that results in unserved load.

The staffing and additional systems required to maintain the same level of functionality in the standalone system as exists in the MISO base case include:

- Staffing requirements (total estimated cost $0.3 million per year 2005-2010).
    - Tariff administration
        - Contracts administration, FERC filings and analysis of FERC filings—one existing full-time equivalent ("FTE") staff.
        - Customer interconnection requests and generation interconnection studies—two existing FTE staff.

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[74] According to reports of the chronology of events of the afternoon of August 14, once the problem cascaded beyond the FirstEnergy system, other control area operators, such as in Michigan, Ontario and New York, and market participants in those regions, did not have sufficient time to react to LMP-based congestion prices to have made a difference, even where LMP pricing rules were in place.

        - ATC development, posting and coordination—two new FTE staff to monitor system and maintain a state-estimator model.
    - Transmission service billing—one new FTE to perform job previously done by an accounting department staff that is now assigned to budgeting.
    - Control area functions—OASIS monitoring, transaction evaluations, approvals and scheduling—two existing FTEs.
    - Real-time reliability evaluations—two existing FTEs to maintain state-estimator model and perform contingency analyses.
- Systems requirements (total estimated cost $0.72 million per year 2005-2010).
    - NERC reliability authority—must contract with MISO, PJM or TVA to perform this function; estimated cost $0.3 million per year.
    - OASIS web site—OATI provides this function; estimated cost $0.3 million per year.
    - Tagging and scheduling—possess systems and capability now; no additional cost.
    - OATI software to assist in verifying OASIS requests, tagging and monthly customer billings for settlement; estimated cost $0.12 million per year.

#### 3.8.3 As a SeTrans Member

SeTrans membership is very unlikely to offer significant reliability benefits to LGE/KU, even if it is operating a Day Two market similar to MISO's. Because LGE/KU is not directly electrically interconnected to SeTrans and is only indirectly connected through TVA, it hardly seems possible that LGE/KU and SeTrans could meaningfully support each others' reliability nor that they could engage in meaningful joint planning that could improve grid reliability. Because LGE/KU has strong interconnections with MISO, it must be the case that the benefits associated with reliability and system planning in the SeTrans scenario (if any) must be lower than that of the MISO scenario.

#### 3.8.4 Within a Kentucky ISO

Even if a Kentucky ISO provided all of the types of reliability and planning studies that MISO engineers offer, the lower economies of scope and scale associated with the statewide system would suggest that it would be more expensive to provide these on a per unit basis. Furthermore, the relatively weak interconnections within the state promise lower reliability benefits.

### 3.9 System Operations Costs

Because an RTO would relieve LGE/KU of some of its system operations responsibilities, LGE/KU system operations costs as an RTO member would be lower than as a standalone utility (though apparently not enough lower to cover the costs of LGE/KU's payments for the RTO's system operations services). The relative interconnectedness of LGE/KU with other systems implies that the reduction in LGE/KU's own system operations costs would be greatest if it were a MISO member, and least if it were a member of a Kentucky ISO or the SeTrans RTO. If LGE/KU chooses to join an alternative RTO, LGE/KU would have at least the same obligations to perform system operation functions as it has a MISO member.

### 3.9.1 As a MISO Member

MISO's assumption of tariff administration and tagging responsibilities did not result in an immediate reduction of workload for LGE/KU's control area operations personnel.[75] This occurred for two reasons. First, LGE/KU's transmission system operations did not expand personnel or facilities to meet the responsibilities imposed under Order Nos. 888 and 889 because of the anticipation that the MISO startup would relieve LGE/KU of these responsibilities. Consequently, during the interim period prior to MISO startup (i.e., 2003) transmission operations were operating at maximum levels. Second, security concerns have induced both MISO and LGE/KU to maintain desks that are staffed around the clock. Nonetheless, LGE/KU's staffing requirements could be reduced following the Day Two market startup in April 2004, given MISO's increased assumption of dispatch of generation units in real time. Thus, LGE/KU is expected to experience a cost reduction that has been estimated to equal $1 million per year.

### 3.9.2 As a Standalone System

If LGE/KU were to leave MISO to operate as a standalone system, it would have to perform nearly all the functions that MISO is currently performing, in particular those functions associated with the OATT, OASIS, invoicing for settlements, interregional transmission planning, and tagging and *ex post* schedule checking. In some cases, as the discussion in Section 3.8.2 laying out the costs of performing these functions suggests, LGE/KU would be assuming some functions that it had heretofore not performed under Order Nos. 888 and 889 requirements for open access transmission. Consequently, LGE/KU would not gain the $1 million per year cost reduction alluded to in Section 3.8.2. Rather it would experience an increase in costs in order to assume these MISO functions. In sum, LGE/KU estimates that it would need an additional $1 million per year in the transmission operations budget to assume the functions MISO is or would be performing for LGE/KU following the start of the Day Two market. Thus the difference between the MISO member option and the standalone system option is $2.0 million for these system operations functions.

### 3.9.3 As a SeTrans Member

LGE/KU's system operations costs would likely be higher than in the MISO base case because the lack of interconnections between LGE/KU and SeTrans would probably require LGE/KU to retain more system operations responsibility than in the base case. The costs of the SeTrans option would approximate the incremental costs of operating as a standalone system.

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75 Communication from L. Monday, Transmission Group.

### 3.9.4 Within a Kentucky ISO

A Kentucky ISO would not significantly reduce LGE/KU's system operations costs, if it continued to operate a separate control area. However, regardless of how Orders No. 888 and 889 functional responsibilities were allocated between LGE/KU and the Kentucky ISO, LGE/KU and its native load customers would still be expected to pay for those services. In addition, the dispatch of the statewide system would still have to contend with the impact of the MISO dispatch, and with the congestion and loop flows that result from the dispatch of the larger Midwest regional market.

## 3.10 Share of Market Implementation and Administration Costs

As a standalone utility, LGE/KU would pay no market implementation and administration fees such as it is currently obligated to pay to MISO; so this cost would be higher under all of the RTO alternatives than under the standalone scenario. The interesting question, however, is whether the expense to LGE/KU of the RTO alternatives is less than the cost savings to LGE/KU from having a smaller system operations function.

Looking only at LGE/KU's payments to RTOs for their implementation and administration costs, the relative sizes and efficiencies of the RTOs matter a great deal. Lacking information to justify differing expectations of the efficiencies of MISO and the SeTrans RTOs, and the Kentucky state ISO, we can reasonably expect that the larger RTOs (MISO and SeTrans) will have lower per-unit costs than the smaller Kentucky ISO.

### 3.10.1 As a MISO Member

To remain a member entails paying "membership" fees that would roughly average $8.45 million per year over the period 2005-2010 to cover startup and market administration costs. In addition, native load customers may see a rate increase in the transmission component of their bills if MISO moves from zonal access charges to a postage stamp pricing system for transmission access at the end of the transition period (i.e., around 2008).[76]

The Midwest ISO's total start-up costs are now forecast to be $270 million. The Midwest ISO estimates that additional capital expenditures totaling $100 million will be required prior to the provision of FTR and Energy Market Services; plus there will be yet another $7 million of expense to develop the common market with PJM.

<u>Schedule 10: ISO Cost Recovery Adder</u>

According to the MISO OATT, "[t]he costs associated with operating the ISO exclusive of those costs recovered pursuant to Schedules 1, 16 or 17 shall be recovered through Schedule 10 charges. The ISO costs to be recovered under this Schedule 10 shall include the ISO's deferred

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[76] "Postage stamp pricing" of transmission service refers to the recovery of the fixed costs of transmission service through a transmission access charge that is the same in all service territories within an RTO. The common alternative is "license plate pricing" under which a different transmission access charge applies to each of the service territories within the RTO.

pre-operating costs, the costs associated with building and operating the Security Center, including capital costs and operating expenses, and costs associated with administering the Tariff."

The Schedule 10 charges for LGE/KU taking point-to-point transmission service are based on actual MWhs of scheduled energy for point-to-point transmission service and actual reserved capacity of point-to-point transmission services multiplied by the duration of the reservation within the month.[77] The Schedule 10 charges for transmission customers taking network integration transmission service are based on actual MWh of scheduled energy for network transmission service and the network customer's monthly network load. The monthly Schedule 10 charges billed to LGE/KU will be based on actual MWh of scheduled energy associated with the LGE/KU's adder load.

Figure 1 shows MISO's Schedule 10 cost recovery forecast. According to MISO, it is expected that the recovery adder will average about $0.136 per MWh in 2004 and gradually decline to $0.114 per MWh by 2010, principally as a result of load and energy sales growth.

The cost to LGE/KU of Schedule 10 charges is estimated to average $5.81 million per year over the period 2005-2010.

### Schedule 16 Costs: Financial Transmission Rights Administrative Service Cost Recovery Adder

According to the MISO OATT, the "FTR Administrative Service Cost Recovery Adder provides for the recovery of all costs incurred by the Transmission Provider (i.e., MISO) in providing the Service, inclusive of all costs resulting from assignment or allocation of costs to the Service. The Transmission Provider's costs incurred in providing the Service include, but are not limited to, costs associated with: 1) coordination of FTR bilateral trading; 2) administration of FTRs through allocation, assignment, auction or any other process accepted by the Commission; 3) support of the Transmission Provider's on-line, internet-based FTR tool; 4) 'simultaneous feasibility' analyses to determine the total combination of FTRs that can be outstanding and accommodated by the Transmission System at a given point in time; and 5) the administration of FTRs and revenue distribution."[78]

The billing determinants for Schedule 16 cost recovery will equal the "total amount of FTR volume for all Primary FTR Holders, expressed in MW." The total FTR volume shall equal the MW of FTR capacity in effect in each hour for all FTRs held during the applicable month for which the FTR Administrative Service Cost Recovery Adder rate is effective, summed over all hours of that month.[79]

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[77] According to the MISO OATT, the reserved capacity rate will be multiplied by billing units of reserved capacity, and the energy rate will be multiplied by billing units of MWh of scheduled energy."

[78] See MISO OATT, Schedule 16.

[79] Each month MISO will determine the FTR Administrative Service Cost Recovery Adder for the next month by dividing budgeted Schedule 16 Costs to be recovered for that month, including true-up amounts from the prior month, by the total quantity of estimated FTRs, expressed in MW, associated with the service.

The most recent MISO estimates (as provided in August 2003) project Schedule 16 charges to average \$0.028/MWh in 2004, rise to \$0.030/MWh by 2006 and fall to \$0.020/MWh by 2007. We assume that the 2007 rate remains in force for the period from 2008 to 2010. The cost to LGE/KU of these charges is projected to average roughly \$1.18 million per year over the period 2005-2010.

Schedule 17 Costs: Energy Market Administrative Service Cost Recovery Adder

Under the MISO OATT, the "Energy Market Support Administrative Service Cost Recovery Adder provides for the recovery of all costs incurred by the Transmission Provider in providing the Service, inclusive of all costs resulting from the assignment or allocation of costs to the Service." MISO's costs incurred in providing the energy market administration include, but are not limited to, costs associated with:

- market modeling and scheduling functions;
- market bidding support;
- locational marginal pricing support;
- market settlements and billing;
- market monitoring functions; and
- enabling the least-cost, security-constrained commitment and dispatch of generating resources to serve load in the MISO control areas while also establishing a spot energy market.

The billing determinants for Schedule 17 cost recovery are all MWh injected into the MISO market by all market participants, including deliveries to MISO from generation located both within MISO and outside of MISO, all MWh taken from MISO by all market participants under point-to-point or network integration transmission services, including MWh delivered to loads located both within MISO and outside of MISO including all out and through transactions using MISO transmission facilities; and all physical or virtual bids or offers that settle in the day-ahead market, but do not actually inject MWh into or extract MWh from MISO in the real-time market." The cost to LGE/KU of Schedule 17 charges is projected to average \$1.46 million per year over the period 2005-2010.

The Schedule 10, 16 and 17 rates, as projected by MISO for the study period, are summarized in Table 3.1. The Schedule 10, 16 and 17 costs for LGE/KU are summarized in Table 3.2. All figures are in nominal dollars. The billing determinants used to prepare this table were based on long-term forecasts of total sales plus sales for resale. By leaving MISO in 2004, LGE/KU could avoid these charges for 2005 through 2010. The net present value of the savings in Schedule 10, 16, and 17 charges, expressed in 2004 dollars, would be \$40.55 million.[80] This means that even if LGE/KU were to pay an exit fee of \$23 million, it would still enjoy a net cost reduction of \$17.55 million in 2004 dollars.

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80 Savings were discounted at the rate of 7% per annum.

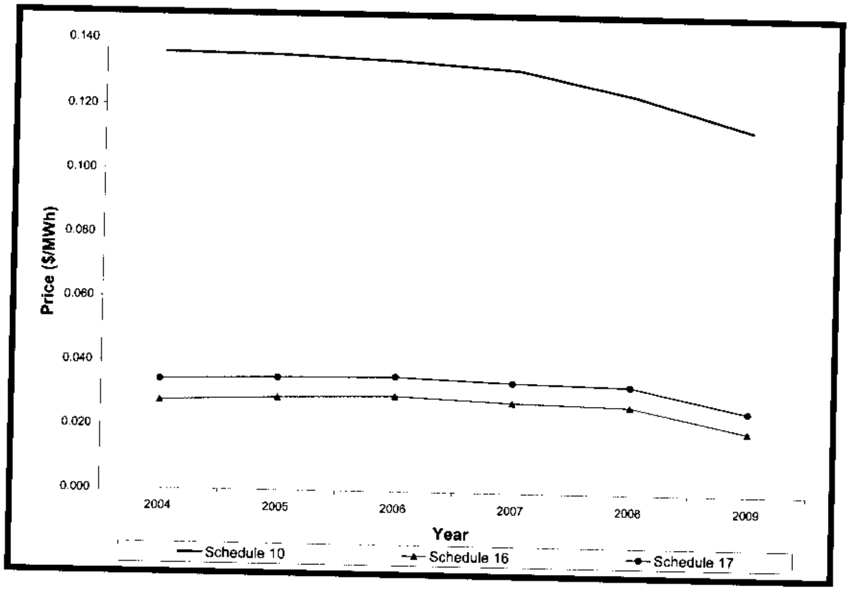


**Figure 3.1. MISO Projected Rates for Schedules 10, 16 & 17**

**Table 3.1 MISO Projected Rates for Schedules 10, 16 & 17**[81]

| | Schedule 10 | | Schedule 16 | | Schedule 17 | |
|---|---|---|---|---|---|---|
| Year | $/MWH | % Change | $/MWH | % Change | $/MWH | % Change |
| 2004 | 0.1360 | | $ 0.0277 | | 0.0343 | |
| 2005 | 0.1355 | -0.37% | $ 0.0289 | 4.33% | 0.0351 | 2.33% |
| 2006 | 0.1341 | -1.03% | $ 0.0297 | 2.77% | 0.0357 | 1.71% |
| 2007 | 0.1317 | -1.79% | $ 0.0281 | -5.39% | 0.0343 | -3.92% |
| 2008 | 0.1241 | -5.77% | $ 0.0272 | -3.20% | 0.0335 | -2.33% |
| 2009 | 0.1135 | -8.54% | $ 0.0196 | -27.94% | 0.0257 | -23.28% |
| 2010[82] | 0.1135 | | $ 0.0196 | | 0.0257 | |

**Table 3.2 LGE/KU's MISO Schedule 10, 16 and 17 Costs (Nominal $ Millions)**

| Year | Schedule 10 | Schedule 16 | Schedule 17 | Total |
|---|---|---|---|---|
| 2005 | 5.95 | 1.27 | 1.54 | 8.76 |
| 2006 | 6.06 | 1.34 | 1.61 | 9.01 |
| 2007 | 6.06 | 1.29 | 1.58 | 9.22 |
| 2008 | 5.81 | 1.27 | 1.57 | 8.94 |
| 2009 | 5.43 | 0.94 | 1.23 | 7.88 |
| 2010 | 5.54 | 0.96 | 1.24 | 8.03 |
| Total | 34.86 | 7.07 | 8.79 | 50.73 |
| Average | 5.81 | 1.18 | 1.46 | 8.45 |

81 Rates as presented to LGE/KU management on July 16, 2003.

82 The MISO's projections of the Schedule rates did not extend to 2010, therefore we assumed they did not change between 2009 and 2010.

Ancillary Market Implementation and Administration Cost Recovery Adder

As a MISO member, LGE/KU would be expected to share in the setup and administrative costs of various ancillary service markets, should MISO choose at some point to develop those markets (i.e., a regulation and frequency response market, a spinning reserves market, and a supplemental reserves market). The best estimate of what this might cost might be based on the costs in other RTO/ISO markets. We have not been able to obtain specific information on these costs. However, we have assumed that the cost of setting up and administering ancillary service markets is in the same proportion to total startup and annual operating costs of an RTO as the value of ancillary services purchased annually is to total value of energy transacted (about 1%). Thus the total cost of starting up the ancillary services market is estimated to be roughly $3.77 million (1% of $377 million startup costs incurred including capital costs) and operating cost would be about $1.40 million annually (1% of a $140 million operating budget). If LGE/KU were allocated a share of these costs on a load ratio basis, its obligation is estimated to be in the neighborhood of $207,350 for startup and $77,000 per year for administration costs (for the period 2006-2010 based on 5.5% load ratio share allocation of costs).

### 3.10.2 As a Standalone System

Operating a standalone system, LGE/KU would not pay any RTO market implementation and administration costs except for those services explicitly used by the trading arm of the companies for trading within MISO. The Schedule 10, 16 and 17 charges for off-system trades with MISO were based on an assumption that LGE/KU would be trading 5% of its total annual energy sales with MISO members. The rates applied to these trades for Schedule 10, 16 and 17 were defined in Section 3.10.1. The results are summarized in Table 3.3.

| Year | Off-system Trades (MWh) | Schedule 10 | Schedule 16 | Schedule 17 | Total |
|---|---|---|---|---|---|
| 2004 | 1,928,255 | $ 262,243 | $ 53,413 | $ 66,139 | $ 381,795 |
| 2005 | 1,970,691 | $ 267,029 | $ 56,953 | $ 69,171 | $ 393,153 |
| 2006 | 2,026,771 | $ 271,790 | $ 60,195 | $ 72,356 | $ 404,341 |
| 2007 | 2,065,001 | $ 271,961 | $ 58,027 | $ 70,830 | $ 400,817 |
| 2008 | 2,101,577 | $ 260,806 | $ 57,163 | $ 70,403 | $ 388,372 |
| 2009 | 2,146,660 | $ 243,646 | $ 42,075 | $ 55,169 | $ 340,890 |
| 2010 | 2,190,351 | $ 248,605 | $ 42,931 | $ 56,292 | $ 347,828 |
| Total | 14,429,307 | $ 1,826,078 | $ 370,756 | $ 460,360 | $ 2,657,194 |

### 3.10.3 As a SeTrans Member

It is almost certain that the costs of SeTrans providing system operations services to LGE/KU must be more expensive than MISO providing these services to LGE/KU. SeTrans' economies of scale will not be much different than that of MISO; but modeling and controlling an electrically distant LGE/KU is bound to impose costs on SeTrans that are not borne by MISO.

Were LGE/KU to join SeTrans, the costs of market implementation and administration are expected to be similar to the MISO scenario SeTrans would recover the costs of RTO setup and administration through the Schedule 10 charge, assessed on all MWh, whether from grandfathered transactions, network integration service or point-to-point service. The administrative fee would recover costs associated with startup, the ISA management fee (including performance incentives),[83] interest from amortization of startup costs, capital costs, etc. The formula rate to be applied to the billing determinants would be based on particular FERC accounts, but the specific formula has yet to be developed. Therefore, it is difficult to estimate the size of the Schedule 10 charges relative to MISO, but it may be reasonable to assume that they would be in the neighborhood of the MISO Schedule 10 charges for LGE/KU. Given the size of SeTrans relative to the sizes of other RTOs including those begun from scratch as well as the tight power pools, the share of startup and administrative costs that LGE/KU would be responsible for would be about the same as for MISO.

### 3.10.4 Within a Kentucky ISO

The decision to form a statewide ISO will depend in part on the costs of its creation from scratch and its operations and administration. Those costs will depend on the extent to which FERC requires a KY-ISO to conform to Order No. 2000, which requires each RTO and ISO to meet certain minimum requirements to support competitive markets.

First, a Kentucky state ISO is likely to have costs that are higher (on a per MWh basis) than those of MISO (and perhaps higher than other existing and planned ISOs and RTOs). Like MISO and SeTrans, a Kentucky state ISO would have to be built from scratch. It is possible that it could be created more inexpensively by keeping to a minimal set of functions, so that it did not incorporate a day-ahead market or the locational pricing that are characteristics of FERC's Standard Market Design ("SMD") and prominent features of other RTOs and ISOs. But because day-ahead markets facilitate unit commitment and locational prices help manage transmission congestion, building a "minimal" ISO will come at the cost of reduced operating efficiencies and may ultimately have to give way to a more complete and more expensive ISO design, if the experiences of PJM, New England, California and the Texas RTO ERCOT can be used as a guide. It is also doubtful that FERC would approve an ISO that did not include a voluntary day-ahead market and locational pricing.

The real disadvantage of a Kentucky ISO relative to MISO, SeTrans, and all of the RTOs is that the Kentucky market is significantly smaller than those of the other RTOs and ISOs. See Table 3.3 for a summary of the basic characteristics of the existing RTOs and ISOs for 2002. The Kentucky market has a total of 1.7 million customers with a combined (non-coincident) summer peak demand roughly equal to 12,400 MW in 2002.[84] In contrast, PJM's 2002 weather-normalized coincident summer peak was 63,762 MW, over 5 times larger. The energy output for Kentucky in 2002 was roughly 80,800 GWh. In contrast, PJM serves an area with a population of over 25 million people and had a 2002 energy output of about 329,000 GWh, roughly 4 times greater.

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83 A major difference between MISO and SeTrans is that the SeTrans ISA is an independent for-profit company contracted to perform all of the functions that an RTO under FERC Order No. 2000 would perform, and will be working under a performance incentive program. Whether this incentive program proves to yield a more efficient management of the SeTrans grid relative to the MISO grid remains to be seen, and it would be difficult at this point to attempt to quantify the effects of such a performance incentive program, especially on individual participating transmission owners.

84 Not weather normalized.

The startup costs and administrative costs of operating a Kentucky ISO would likely be as great as those experienced by the other ISOs, in particular those that did not have the historical advantage of operating as a tight power pool, such as in PJM, New York and New England. The economies of scope and scale that can be gained through the increase in size of the market served will not be captured by a Kentucky ISO to the extent that they will be (or have been) captured in the other ISOs. These costs would of necessity be spread over a smaller volume of business, implying a higher cost per unit of business.

**Table 3.3 Summary Statistics for Kentucky, RTOs and ISOs**

| Characteristic | KY | CA ISO | ISO New England | MISO | New York ISO | PJM | SeTrans | ERCOT (Texas ) |
|---|---|---|---|---|---|---|---|---|
| No. of Customers (millions) | 1.7 | 30.0 (pop.) | 6.5 | 20 | 7.0 | 25.0 (pop.) | 8 | 21.0 (pop.) |
| Miles of High-Voltage Transmission (000s circuit miles) | 2.6[85] | 25.5 | 8.0 | 100 | 27.0 | 20.0 | 40 | 37.5 |
| Generation Capacity (000s MW) | 10.0 | 54.0 | 31.0 | 155 | 37.1 | 76.0 | 70 | 75.0 |
| Summer Peak Load (000s MW) | 12.4 | 43.0 | 25.4 | 130 | 31.4 | 63.8 | 60 | 57.6 |

Second, Kentucky does not have a transmission system that is internally well integrated. For good geographical and historical reasons, northern Kentucky's power system is well integrated with those of Indiana and Ohio; southern Kentucky's power system is integrated with that of Tennessee; and eastern Kentucky's power system is integrated with those of West Virginia and Virginia. The transmission links between northern Kentucky, southern Kentucky, and eastern Kentucky are relatively weak. These weaknesses have been acknowledged by LGE/KU in its most recent integrated resource plan. In terms of the physics of the transmission system, it makes little sense to draw an ISO boundary at the state line. For the Kentucky grid to be well interconnected would require substantial investments in infrastructure upgrades and expansions that may be efficient from a state perspective to achieve a lower-cost dispatch, but would not necessarily be efficient from the broader regional perspective within which the Kentucky grid must nevertheless operate. And again, the costs of such grid-strengthening investments will have to be recovered from a smaller volume of energy sales and peak load.

Third, there will be several regulatory hurdles that a state ISO would have to overcome that would add to the costs of creating such an organization. As suggested in FERC's White Paper, any final rule on SMD will not require ISOs to satisfy the Order No. 2000 scope and configuration characteristics of RTOs, which means that a smaller ISO, perhaps even as small as the Kentucky ISO, possibly could be found acceptable. However, the White Paper also notes that "if for a specific RTO or ISO it can be demonstrated to the Commission that the costs of implementing any feature of the market platform outweigh its benefits, the Commission will not

85 This number is based on circuit miles for lines 69kV and above for the LGE/KU system only, information on circuit miles for other entities in Kentucky was not obtained.

require implementation of the feature for that particular RTO or ISO."[86] Thus, any attempt to reduce costs by eliminating any function or feature defined in Order No. 2000 must be accompanied by a convincing cost-benefit analysis, which may be a tall order to fill. Finally, FERC has indicated that a final rule on SMD will require all ISOs and RTOs to actively pursue interregional coordination, including the elimination of the payment of multiple access fees for transactions that cross ISO and RTO borders. Consequently, any chance of spreading the fixed or administrative costs of the state ISO across a base that included through and out traffic would be substantially eliminated. And a Kentucky ISO will still be required to participate in an RTO (MISO most likely), insofar as a final rule would make an RTO the sole provider of transmission service and sole administrator of the open access tariff, including the requirement that an RTO have the sole authority for the evaluation and approval of all requests for transmission service including requests for new interconnections.

Based on the operating budgets for other ISOs/RTOs in the country, the budget for the annual operation and administration of a statewide ISO may be on the order of $80 to $100 million per year. The estimated range is based on assuming the operations/administration of a statewide ISO would be similar to those in operation today, the California Independent System Operator ("CA ISO"), the New York Independent System Operator ("NYISO"), the Independent System Operator of New England ("ISONE"), which assume full functional responsibilities for grid management and market administration under Order No. 2000. Assuming the costs of performing these functions were approximately the same as for those existing ISOs, with CAISO being the most expensive (roughly $1.00/MWh) and PJM and ISONE roughly equal at about $0.45/MWh.

Participation in a Kentucky ISO will require LGE/KU to pay a share of the ISO's administrative costs. We have already indicated that we believe these costs will be at least as high as on a per unit basis as those encountered by the other RTOs and ISOs currently in operation. Thus we see no advantage to this option from LGE/KU's perspective or that of its native load customers.

## 3.11 Resource Adequacy Obligation

### 3.11.1 As a MISO Member

MISO membership does not appear to change LGE/KU's resource adequacy obligation relative to what it would be as a standalone utility. The integrated resource plan (IRP) filed by the combined companies in the fall of 2002 with the KPSC, which is the governing document for fulfilling the companies' resource adequacy requirements, says that the companies' planned resource acquisition considers, as it should, the economics and practicality of available options to meet customer needs at the lowest possible costs. This the planned resources that flow from approach, which include improvements to operating efficiency of existing facilities, demand-side programs, non-utility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities, would appear to be just as necessary to ensure that LGE/KU satisfies its obligation to serve at lowest cost. The major impact of membership in MISO will be the outcome of MISO's Indiana-Kentucky regional

86 White Paper, at 2.

generation interconnection study that will determine the extent of transmission facilities upgrades or expansion to accommodate LGE/KU's four plant additions (i.e., the Trimble County units).[87]

### 3.11.1 As a Standalone System

As a standalone utility, LGE/KU's resource adequacy obligation would be that imposed by the state under the existing Kentucky statutes and regulations; while as a member of an RTO, the resource adequacy obligation would depend upon the RTO's rules as well as on Kentucky's rules. We have not been able to determine whether there would be a difference between the MISO base case and the standalone system alternative.

### 3.11.1 As a SeTrans Member

Given the lack of interconnection between LGE/KU and SeTrans, any resource adequacy obligation LGE/KU has would not likely depend on SeTrans standards, since whatever reserves LGE/KU has or reserves that other SeTrans members have, will not be dispatchable in a complementary way in such a disconnected system. Under an assumption that the ECAR reserve sharing arrangement will continue regardless of LGE/KU's RTO arrangement, the costs to meet resource adequacy obligations should not differ from those in the MISO base case. However, in the unlikely event that the ECAR arrangement is not continued, the costs of meeting a resource adequacy obligation are likely to be higher if LGE/KU is a SeTrans member because it cannot rely on other SeTrans members for any sort of mutually beneficial, cost-reducing sharing arrangements.

### 3.11.1 Within a Kentucky ISO

As for the Kentucky ISO option, one would expect that precisely the same Kentucky-based obligations that LGE/KU has as a standalone utility, would apply to a Kentucky ISO's members. Additional obligations would be expected imposed by ECAR, NERC or by FERC, similar to what they are now.

## 3.12 Order No. 2000 and SMD Implementation Obligation

FERC jurisdictional utilities (including LGE/KU) must comply with Order No. 2000, but are not yet required to comply with the proposed SMD or its Wholesale Market Platform variant. It is uncertain if or when some version of SMD might become a final rule to which utilities must comply. Proposed Congressional legislation would delay FERC's implementation of a final rule on SMD until the end of 2005, at the earliest. However, this legislation would not overturn or

[87] This regional interconnection study has yet to be conducted, although it has been in the planning stages for at least a year and a half.

disrupt the mechanisms already in place or being put in place within the existing regional markets (i.e., PJM, NYISO, ISONE, CAISO and MISO).[88]

As a standalone utility, LGE/KU would be under no obligation to implement FERC's proposed SMD. However, it would still be required to comply with particular features of Order No. 2000. As a member of MISO or SeTrans, LGE/KU would indirectly pay the additional costs of what is equivalent to SMD compliance because both MISO and SeTrans, in complying with Order No. 2000, have decided to implement market designs that incorporate many of the features of FERC's SMD. Indeed, through Schedule 10, 16 and 17 charges, LGE/KU is already paying or will be paying MISO for its compliance with Order No. 2000 that is similar in the design of the Day Two market to FERC's SMD. It is likely that LGE/KU would face at least as costly an obligation to SeTrans as part of the SeTrans Day Two market as it would in the MISO Day Two market.

There would appear to be no obligation to implement SMD under a Kentucky ISO scenario, assuming FERC would even approve a statewide ISO. However, at present, Order No. 2000 applies and there is no SMD obligation in that, unless FERC was to insist on some form of a wholesale market platform as a condition for approving the statewide ISO. FERC has indicated in the White Paper that it would provide utilities, states and regions with greater flexibility to configure wholesale markets and evolve to a wholesale market platform. Depending on how much flexibility currently exists in Order No. 2000 and would be contained in a final rule on a wholesale market platform, a Kentucky ISO may be able to take on only a minimal set of functions that would reduce the incremental costs of this option relative to the base case. However, FERC could require the full complement of Order No. 2000 RTO functions for the Kentucky ISO.[89]

### 3.13 Obligation to Pay MISO Exit Fees

For all alternatives other than continued MISO membership, LGE/KU must pay exit fees. Such exit fees are estimated to be about $23 million as discussed below.

According to the MISO TOA, a "Member who is also an Owner may, upon submission of a written notice of withdrawal to the President, commence a process of withdrawal of its facilities" from MISO.[90] Should LGE/KU decide to withdraw, however, under the standard withdrawal rules, the withdrawal will not become effective until December 31 of the calendar year following the calendar year in which notice is given. This means that should LGE/KU decide to withdraw and file a notice with MISO and FERC as early as January 1, 2004, the withdrawal would not be effective until the end of 2005. Therefore, the payment of exit fees (discussed below) associated with LGE/KU's departure from MISO would come due in 2006. All other financial obligations that LGE/KU would have under the TOA and the MISO OATT will be in effect until the

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88 Senator P. Domenici, substitute for the Senate version of H.R.6., Sec 1121, Implementation Date for Proposed Rulemaking on SMD ("H.R. 6 Sub").

89 H.R. 6 Sub, Section 1121, delays implementation of SMD rules until the middle of 2005 and requires FERC to issue a notice of proposed rulemaking.

90 MISO TOA Article V, Withdrawal of Members, Section I para. 1.

effective date of the withdrawal. So, at the earliest, LGE/KU would not be "free" of MISO until January 2006.

In accordance with the MISO TOA, LGE/KU could exit MISO earlier, however, if "any state regulatory authority refuses to permit participation by a signatory or imposes conditions on such participation which adversely affect a signatory in the sole judgment of that signatory, such signatory . . . may, no later than thirty (30) days after the date of such action, or after any such signatory concludes reasonably that the state regulatory authority has refused to act, and upon notice to all signatories, withdraw from this Agreement."[91] Thus, to the extent the KPSC directs LGE/KU to withdraw from MISO (based on a finding that the benefits enjoyed by Kentucky's citizens are insufficient to justify further participation), LGE/KU could presumably take advantage of an earlier withdrawal date under the terms of the TOA.

If LGE/KU did elect (or was ordered) to withdraw from MISO, it would be responsible for "[a]ll financial obligations incurred and payments applicable to time periods prior to" the date of withdrawal.[92] Based on MISO financial statements and informational filings to FERC, MISO has incurred approximately $213 million in capital costs as of the close of 2002, and the 2003 budget increases that figure to approximately $270 million. Not included in this estimate is an additional capital cost outlay of at least $100 million associated with MISO's implementation of its Day Two Congestion Management program, and another $7 million for implementation of the MISO/PJM joint and common market, resulting in capital cost expenditures totaling approximately $377 million. In addition, MISO's estimated on-going operating expenses according to the 2003 budget total approximately $146 million.

*In the event of a December 31, 2005 withdrawal*, LGE/KU would be liable for its *pro rata* share of approximately $377 million in capital expenditures and a share of roughly $140 million/year in operating expenses applicable to periods prior to December 31, 2005. LGE/KU's *pro rata* share as of December 31, 2005 would be based on the size of MISO's member load at that time. MISO's combined load is expected to total approximately 860 GWh, of which the LGE/KU's *pro rata* share would be approximately 5.5 percent.[93] Applying this percentage to a total capital cost outlay of $377 million yields a total capital cost financial commitment of approximately $20.74 million as of December 31, 2005. Similarly, the Companies' operating cost exposure would total almost $7.70 million per year, applicable to periods up to December 31, 2005, or $15.40 million for the period 2004-2005. Consequently, our estimate of the total withdrawal fee is $36.14 million.

*In the event that a KPSC order leads to withdrawal effective the end of 2004*, LGE/KU's capital cost burden could drop by approximately $5.5 million, from $20.74 million to $15.24 million (5.5 % of an estimated $277 million), assuming a total MISO member load of approximately 820,000 GWh. Again, the Companies' operating cost exposure would total almost $7.70 million per year, applicable to periods prior to the effective date of withdrawal (i.e., the end of 2004). The total exist fee is approximately $22.94 million.

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91 MISO TOA, Article VII, Regulatory, Tax and Other Authorities, Section A.3.

92 MISO TOA, Article V, Section II.

93 LGE/KU's *pro rata* share at the time it exits under this scenario is based on the ratio of LGE/KU's projections of the total MWh sales divided by the projected MWh sales for the entire MISO region for 2005.

### 3.14 Legal, Regulatory and Transaction Costs

The legal, regulatory and transaction costs associated with LGE/KU's membership in MISO are estimated to be in the neighborhood of a million dollars per year; and we would reasonably expect these costs for its membership in SeTrans or a Kentucky ISO would be similar. These costs are those of paying staff to participate in numerous meetings, to prepare information and proposals, participate in hearings regarding RTO policy issues, prepare pleadings regarding changes in RTO policies and so forth. We have assumed these costs to average $0.80 million per year. Corresponding costs for the standalone system option are estimated to average $0.40 million per year.

In addition, there are fees collected from all MISO transmission owners to recover what MISO pays to FERC to support the FERC budget. Before joining MISO, LGE/KU paid approximately $0.50 million per year. As a member of MISO, LGE/KU estimated that it will pay approximately $1.34 million per year.[94]

## 4. DIFFERENCES BETWEEN THE MISO AND STANDALONE SYSTEM OPTIONS

Tables 4.1 and 4.2 present a breakeven analysis of the MISO RTO base case option, and the alternative of operating as a standalone system. The benefits, represented as incremental savings, and the costs, represented as incremental costs, of operating as a standalone system are contained in Table 4.1 for a "Base Budget Scenario" in which the MISO capital and operating budgets are assumed to grow at the rates that are implied by the forecasts of the Schedules 10, 16 and 17 charges (expressed in $/MWh) as presented to the LGE/KU management on August 5, 2003. Table 4.2 presents a "Budget Growth Scenario" in which the MISO capital and operating budget increases at the rate of 10% per year above the 2003 budget for the period from 2004-2007 and then declines at 3% per year over the period from 2008 to 2010. The assumptions underlying both scenarios are presented in Table 4.3. The Base Budget Scenario and the Budget Growth Scenario differ principally in terms of the incremental savings arising from avoided Implementation & Administration charges. Savings that would result from LGE/KU withdrawing from MISO to operate as a standalone system fall into three categories: (1) system operations and transmission related costs, (2) implementation and administration costs and (3) legal, regulatory and transaction costs.

System operations and transmission related cost savings are composed of reductions in budgetary items for the Marketing, Risk Management and Development ("MRMD") Department (i.e., the trading arm of LGE/KU), net savings in transmission costs associated with off-system trading, reductions in expected miscellaneous uplift charges that LGE/LU would pay as a MISO member (e.g., inadvertent dispatch of generation and miscellaneous dispatch costs that cannot be directly assigned to market participants), and lower congestion and redispatch costs that result from operating as a standalone system and not being exposed to its share of regional congestion costs. As explained in Section 3.10, LGE/KU would also avoid paying its load ratio share of Schedule 10, 16 and 17 charges to recover MISO's implementation and administration costs, although it does not avoid paying a portion of those in terms of the exit fee estimated at $23 million, as

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94 This figure would decrease if the number of jurisdictional utilities that become members of RTOs increases.

described in Section 3.13. LGE/KU also expects to see a reduction in its legal, regulatory and transaction costs associated with MISO membership. These costs are discussed in Section 3.14.

Additional costs that LGE/KU expects to incur if it withdrew from MISO to operate as a standalone system can be grouped under four major headings: (1) an exit fee, estimated to be $23 million and paid at the end of 2004, (2) system operations costs, (3) reduced transmission revenues and (4) implementation and administration costs for off-system trades in MISO. The exit fee is discussed in Section 3.13. LGE/KU expects an increase in system operations costs to operate a standalone system because it will have to perform functions that MISO currently performs, some of which LGE/KU has heretofore never performed. These costs are discussed in Section 3.8.2, under reliability and planning. Reductions in transmission revenues arise from LGE/KU forgoing its share of transitional lost transmission revenues that it would have received as a result of settlements addressing the elimination of pancaked transmission charges within MISO and between MISO and PJM. This is discussed in Section 3.6. The implementation and administration costs (i.e., Schedules 10, 16, and 17 charges) are included here as an "additional cost" because they were not netted out of the Schedules 10, 16 and 17 charges listed under Savings in Tables 4.1 and 4.2. These charges are discussed in Section 3.10.2.

The results of the breakeven analysis under either scenario suggests that the preferred option is for LGE/KU to operate as a standalone system. A conservative approach was taken in estimating the incremental savings and incremental costs for the standalone system. Therefore, the Base Budget Scenario represents a lower-bound estimate of the savings that can be achieved by running a standalone system. The average savings per year under the Base Budget Scenario is $11.13 million. Thus, even if LGE/KU must pay $23 million to exit MISO in 2004, it recovers that fee by the end of 2006. Under the assumption that the MISO budget grows at the rate of 10% per year from 2005-2007, the company recovers the fee within the first 18 months.

**Table 4.1 Breakeven Analysis of MISO vs. Standalone System Option: Base Budget Scenario, exit effective 12/31/04 ($ Millions)**

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|
| **Savings** | | | | | | | |
| **System Operations & Transmission Related Costs** | | | | | | | |
| *MRMD Staffing, Training, Consulting [1]* | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| *Net Off-system Transmission Costs (MISO) [2]* | | 6.40 | 5.90 | 4.80 | 4.80 | 4.80 | 4.80 |
| *Miscellaneous MISO Uplift Charges [3]* | | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 |
| *Net Congestion Cost/Redispatch [4]* | | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 |
| **Implementation & Administration Costs** | | | | | | | |
| *Schedule 10 Charges [5]* | | 5.95 | 6.06 | 6.06 | 5.81 | 5.43 | 5.54 |
| *Schedule 16 Charges [5]* | | 1.27 | 1.34 | 1.29 | 1.27 | 0.94 | 0.96 |
| *Schedule 17 Charges [5]* | | 1.54 | 1.61 | 1.58 | 1.57 | 1.23 | 1.25 |
| *Ancillary Market Cost [6]* | | | | 0.28 | 0.28 | 0.28 | 0.28 |
| **Legal, Regulatory & Transaction Costs** | | | | | | | |
| *Net Committee Participation, Contracts [7]* | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| *Net FERC Attachment O Fees [8]* | | 0.86 | 0.86 | 0.86 | 0.86 | 0.86 | 0.86 |
| **Total Savings** | | 19.32 | 19.08 | 18.18 | 17.90 | 16.84 | 17.00 |
| **Additional Costs** | | | | | | | |
| **Pay MISO Exit Fee [9]** | -23.00 | | | | | | |
| **System Operations Costs** | | | | | | | |
| *Additional Staffing [10]* | | -0.30 | -0.30 | -0.30 | -0.30 | -0.30 | -0.30 |
| *Systems Related Costs [11]* | | -0.72 | -0.72 | -0.72 | -0.72 | -0.72 | -0.72 |
| **Lost Revenues** | | | | | | | |
| *Lost RTOR Revenue Transitional Recovery [12]* | | -1.50 | -1.50 | | | | |
| *Lost FTR Revenue [13]* | | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 |
| *Other Lost Revenues from MISO Members [14]* | | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 |
| *Grandfathered Schedule 1 Revenue [15]* | | -1.00 | -1.00 | -1.00 | -1.00 | -1.00 | -1.00 |
| **Implementation & Administration Costs OST** | | | | | | | |
| *Schedule 10 Charges [16]* | | -0.27 | -0.27 | -0.27 | -0.26 | -0.24 | -0.25 |
| *Schedule 16 Charges [16]* | | -0.06 | -0.06 | -0.06 | -0.06 | -0.04 | -0.04 |
| *Schedule 17 Charges [16]* | | -0.07 | -0.07 | -0.07 | -0.07 | -0.06 | -0.06 |
| **Total Additional Costs** | -23.00 | -7.91 | -7.92 | -6.42 | -6.41 | -6.36 | -6.37 |
| **Net Savings (Costs)** | -23.00 | 11.41 | 11.15 | 11.76 | 11.49 | 10.48 | 10.63 |
| **Net Present Value in 2004 [17]** | -23.00 | 10.67 | 9.74 | 9.60 | 8.77 | 7.48 | 7.09 |
| **Cumulative Net Savings (Nominal $)** | -23.00 | -11.59 | -0.46 | 11.28 | 22.75 | 33.21 | 43.82 |
| **Cumulative Net Savings (NPV) [17]** | -23.00 | -12.33 | -2.61 | 6.97 | 15.72 | 23.18 | 30.25 |

**Table 4.2 Breakeven Analysis of MISO vs. Standalone System Option: Budget Growth Scenario, exit effective 12/31/04 ($ Millions)**

| Savings | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|
| **System Operations & Transmission Related Costs** | | | | | | | |
| *MRMD Staffing, Training, Consulting [1]* | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| *Net Off-system Transmission Costs (MISO) [2]* | | 6.40 | 5.90 | 4.80 | 4.80 | 4.80 | 4.80 |
| *Miscellaneous MISO Uplift Charges [3]* | | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 |
| *Net Congestion Cost/Redispatch [4]* | | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 |
| **Implementation & Administration Costs** | | | | | | | |
| *Total of Schedules 10,16,17 Charges [5]* | | 14.76 | 16.24 | 17.86 | 17.33 | 16.81 | 16.30 |
| *Ancillary Market Cost [6]* | | | | 0.28 | 0.28 | 0.28 | 0.28 |
| **Legal, Regulatory & Transaction Costs** | | | | | | | |
| *Net Committee Participation, Contracts [7]* | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| *Net FERC Attachment O Fees [8]* | | 0.86 | 086 | 0.86 | 0.86 | 0.86 | 0.86 |
| **Total Savings** | | 26.56 | 27.54 | 28.34 | 27.81 | 27.29 | 26.78 |
| **Additional Costs** | | | | | | | |
| **Pay MISO Exit Fee [9]** | -23.00 | | | | | | |
| **System Operations Costs** | | | | | | | |
| *Additional Staffing [10]* | | -0.30 | -0.30 | -0.30 | -0.30 | -0.30 | -0.30 |
| *Systems Related Costs [11]* | | -0.72 | -0.72 | -0.72 | -0.72 | -0.72 | -0.72 |
| **Lost Revenues** | | | | | | | |
| *Lost RTOR Revenue Transitional Recovery [12]* | | -1.50 | -1.50 | | | | |
| *Lost FTR Revenue [13]* | | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 |
| *Other Lost Revenues from MISO Members [14]* | | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 | -2.00 |
| *Grandfathered Schedule 1 Revenue [15]* | | -1.00 | -1.00 | -1.00 | -1.00 | -1.00 | -1.00 |
| **Implementation & Administration Costs OST** | | | | | | | |
| *Schedule 10 Charges [16]* | | -0.27 | -0.27 | -0.27 | -0.26 | -0.24 | -0.25 |
| *Schedule 16 Charges [16]* | | -0.06 | -0.06 | -0.06 | -0.06 | -0.04 | -0.04 |
| *Schedule 17 Charges [16]* | | -0.07 | -0.07 | -0.07 | -0.07 | -0.06 | -0.06 |
| **Total Additional Costs** | -23.00 | -7.91 | -7.92 | -6.42 | -6.41 | -6.36 | -6.37 |
| **Net Savings** | -23.00 | 18.65 | 19.62 | 21.92 | 21.40 | 20.93 | 20.42 |
| **Net Present Value in 2004 [17]** | -23.00 | 17.43 | 17.14 | 17.90 | 16.33 | 14.93 | 13.61 |
| **Cumulative Net Savings (Nominal $)** | -23.00 | -4.35 | 15.21 | 37.15 | 58.53 | 79.44 | 99.83 |
| **Cumulative Net Savings (NPV) [17]** | -23.00 | -5.57 | 11.55 | 29.43 | 45.74 | 60.64 | 74.24 |

**Table 3.3 Assumptions**

| # | Base Budget Scenario | Budget Growth Scenario |
|---|---|---|
| [1] | Based on LGE/KU budget sheet; assumes some contractual services from MISO or third parties will not be needed, on-going training of staff for participation in MISO Day 2 Market not needed and two additional FTE staff not needed. | |
| [2] | Based on LGE/KU budget sheet--net amount: equals the expected payments to MISO for all off-system trades as a MISO member minus expected payments for trades within MISO under the standalone system option minus LGE/KU's load ratio share of the revenue MISO receives for Schedule 7 & 8 service from all MISO transmission owners. | |
| [3] | Based on an assumption that LGE/KU would pay a load ratio share of the costs in the Day Two market associated with inadvertent dispatch of generation and other miscellaneous dispatch costs that cannot be assigned directly to market participants. | |
| [4] | Based on an assumption that under a feasibility constraint in the Day Two Market, LGE/KU would only receive FTRs sufficient to hedge 80% of its congestion costs, which includes the compensation of others for LGE/KU's parallel flows; historical congestion/redispatch costs are $1.2 million per year; MISO simulation of congestion costs for a typical year implies that if LGE/KU was not hedged, its share of congestion costs would be about $16 million, and if LGE/KU were 80% hedged, the unhedged cost would be $3.2 million; therefore the net is expected to average $2 million per year. | |
| [5] | Based on forecasts of energy sales plus sales for resale multiplied by MISO forecasted rates expressed in $/MWh; rates used were presented to LGE/KU management Aug. 5, 2003 by MISO. | Based on assumption that MISO budget follows ISO trend pattern and grows at 10% rate from 2003 budget for period 2004-2007 and then declines at 3% rate 2008-2010; the cost to LGE/KU is based on 5.5% share load ratio share. |
| [6] | Based on assumption that ancillary market implementation & administration budget will be in same proportion to total I&M budget as ancillary market energy value is to total energy market value; proportions based on NYISO values; further assume that LGE/KU would be allocated a 5.5% load ratio share. Refer to Section 3.10.1. | |
| [7] | Based on an assumption that costs in MISO are $0.9 million per year and costs as standalone would be $0.5 million per year. Refer to Section 3.14. | |
| [8] | Based on LGE/KU forecasted Attachment O fee of $1.40 million per year if in MISO minus 2002 fee $ 0.54 million which was based on LGE/KU not a member of MISO. Refer to Section 3.14. | |
| [9] | Estimated cost of exit fee, assume exit 12/31/04; 5.5% load ratio share of capital budget of $277 million and operating budget of $140 million. | |
| [10] | Based on LGE/KU budget sheet; estimate of additional staffing necessary to perform MISO security, OASIS and settlement functions. Refer to Section 3.8.2 for additional details. | |
| [11] | Based on LGE/KU budget sheet; estimate of additional systems requirements to perform MISO security & OASIS functions. Refer to Section 3.8.2 for additional details. | |
| [12] | Based on assumption that total transitional revenues will be $3 million over two years, FERC Order in EL02-111 | |
| [13] | Based on an assumption that LGE/KU would receive its load ratio share of the revenues MISO receives from selling excess FTRs. Excess FTR revenue was assumed to be $36 million annually. | |
| [14] | Based on historical monthly settlement files supplied by MISO for LGE/KU's allocation of revenues received from other MISO members. | |
| [15] | Assumes new Schedules 1& 9 rates under a standalone system option will be lower than the MISO Schedule 1 & 9 rates because the MISO rate is based on a 12.88 % ROE, which will be reduced, and the MISO Schedule 1 Rate is now ten times higher than LGE/KU's Schedule 1 rate prior to LGE/KU joining MISO. | |
| [16] | Based on estimate of off-system trades with MISO members of 5% of energy sales plus sales for resale; rates are MISO forecasts of Sch. 10, 16, or 17 in $/MWh as presented to LGE/KU management by MISO on August 5, 2003. | |
| [17] | Based on assumed discount rate of 7% per annum. | |

## 5. POTENTIAL IMPACT ON NATIVE LOAD CUSTOMERS

Considering the breakeven analysis presented in Table 4.1 above, the net savings in nominal dollars foregone if LGE/KU chose to remain a member of MISO will average approximately $11.13 million per year over the period 2005 to 2010. The net present value of the net cumulative savings over the period 2005 to 2010 is estimated to be $30.23 million. Under the companies' forecast of energy sales to native load customers[95] over the period 2005 to 2010, which is 212,500 GWh, if LGE/KU remained a member of MISO, the savings that would be foregone in 2004 dollars translates into an average cost of about 0.14 mills per kWh. For the average residential customer (i.e., a household) that consumes 12 thousand kWh per year, the foregone savings from LGE/KU's staying in MISO would be about $1.40 per year.

When expressed in these terms, it could be argued that the impact on the typical residential customer is so slight that it would likely not be noticed, but this would be missing the point of the breakeven analysis and the comparisons drawn between the costs of the MISO option and the incremental costs of the standalone system option. The estimated annual savings associated with a standalone system option for LGE/KU is $11.13 million. The total savings over the period 2005-2010 will be $53.23 million in net present value terms. The Companies would recover the $23 million exit fee by early 2007, in less than three years from the time they exit. By 2010, the Companies will have saved an estimated $30.23 million in net present value terms beyond the payment of the exit fee. The decision to pay $23 million to withdraw from MISO to save $30.23 million more than the exit fee would appear to be an economically wise decision, in light of the difficulty in determining a correspondingly larger value that can be assigned to the benefits of continued MISO membership.

## 6. SUMMARY OF RTO COST-BENEFIT STUDIES

Recent studies of the costs and benefits of RTO formation provide remarkably similar results and suggest generally what might be revealed in a more targeted analysis, albeit from the perspective of an individual utility and its native load customers. The short-term benefit on average has been estimated to be about $0.20/MWh (savings are mostly in production costs) while the short-term incremental cost averages about $0.24/MWh (this stems primarily from startup costs). The long-term benefit has been estimated to fall in the range of $0.35 per MWh to $1.00 per MWh, and the long-term (total) cost averages roughly $0.44/MWh. Therefore, the net benefit long term is between -$0.08 per MWh and $0.56/MWh.

Three general conclusions can be reached from these studies. First, in the short-term there is no net benefit to RTO formation, and perhaps to RTO membership. Second, RTOs are expensive to get organized and to run. For example, the current generation and transmission dispatch center costs for the 84 largest jurisdictional utilities is about $400/MW-year, whereas the generation and transmission dispatch center costs for the existing RTOs is about $1,400/MW-year.[96] The savings in production costs are offset by the costs of implementation and administration. Third, the long-term benefits (over 15 to 20 years) could be significant, although the estimates are

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[95] Refer to Table 2.1 in the Report.

[96] U.S. Department of Energy, "Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design," April 30, 2003.

tenuous. While an analysis of the MISO and SeTrans RTO options may produce similar results, differences may arise when viewed from LGE/KU's perspective. In light of these results, the prospect of creating a Kentucky ISO would be faced with the same or similar short-term and long-term costs without the benefit of a fully integrated regional system that might enable the savings to be achieved in production costs.

## 7. CONCLUSIONS

At the request of LGE/KU, Christensen Associates undertook an investigation of four options for LGE/KU's RTO participation:

- Remaining a member of MISO;
- Operating as a stand-alone transmission system;
- Joining an alternative RTO (e.g., SeTrans); and
- Participating in the formation a state-wide independent system operator for Kentucky.

In conducting this investigation, we have considered only economic issues, leaving the legal and regulatory feasibility of these options to the appropriate experts.

We were able to reasonably quantify only some of the factors that must be considered in choosing among the options, and even then these are subject to uncertainty. For all categories of benefits and costs, even those most susceptible to quantification, the uncertainties become larger as one looks to estimate longer-term benefits and costs. However, we have concluded that many factors will not vary significantly across the various options. Perhaps the most certain cost to the company associated with a change from the MISO option is the exit fee. To pursue any other RTO option, LGE/KU must withdraw from MISO, which entails FERC approval—except possibly where the KPSC orders LGE/KU out—and payment of an exit fee estimated to be about $23 million.

<u>As a Standalone System</u>

Withdrawal enables LGE/KU as standalone system to avoid at least $8.45 million per year in implementation and administration charges. When all savings and additional costs are considered, LGE/KU may expect to net a savings of approximately $11.13 million per year in nominal dollars and $8.87 million per year in net present value terms.[97] The savings in nominal dollars represents about 16% of the annual transmission revenue requirement.[98] The exit fee could be recovered through savings in less than three years and by 2010 the net present value of additional savings will exceed $30 million. LGE/KU and its native load customers can still benefit from trading opportunities with MISO members because LGE/KU will be a first-tier utility vis-à-vis MISO.

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97 This is a net present value in 2004 dollars discounted at 7%.

98 This assumes that the annual transmission revenue requirement is roughly $70 million.

**Table 7.1 Breakeven Analysis of MISO vs. Standalone Options (Exit 12/04)**

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|
| Savings ($Millions) | | | | | | | |
| System Operations Costs | | 9.30 | 8.80 | 7.70 | 7.70 | 7.70 | 7.70 |
| Implementation & Administration Costs | | 8.76 | 9.01 | 9.22 | 8.94 | 7.88 | 8.03 |
| Legal, Regulatory & Transaction Costs (net) | | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |
| Total Savings | | 19.31 | 19.06 | 18.16 | 17.88 | 16.82 | 16.98 |
| Additional Costs ($Millions) | | | | | | | |
| Pay MISO Exit | -23.00 | | | | | | |
| System Operations Costs | | -1.02 | -1.02 | -1.02 | -1.02 | -1.02 | -1.02 |
| Lost Revenues | | -6.50 | -6.50 | -5.00 | -5.00 | -5.00 | -5.00 |
| Implementation & Administration Costs for Off-System Trades | | -0.39 | -0.40 | -0.40 | -0.39 | -0.34 | -0.35 |
| Total Additional Costs | -23.00 | -7.91 | -7.92 | -6.42 | -6.41 | -6.36 | -6.37 |
| Net Savings (Costs) | -23.00 | 11.39 | 11.13 | 11.74 | 11.47 | 10.46 | 10.61 |
| Net Cumulative Savings (Costs) Nominal $ | -23.00 | -11.61 | -0.48 | 11.26 | 22.73 | 33.19 | 43.80 |
| Cumulative Net Savings (Costs) NPV | -23.00 | -12.35 | -2.63 | 6.95 | 15.70 | 23.16 | 30.23 |

<u>As a Member of SeTrans</u>

In addition to the fact that LGE/KU would have to pay an exit fee of $23 million, there may be even greater obstacles to this RTO choice. Since one of the major benefits of RTOs arises from the efficiency of generation unit commitment and dispatch, given that LGE/KU is so poorly interconnected with SeTrans it is difficult to see how the joint commitment and dispatch of SeTrans and LGE/KU could be significantly more efficient than separate commitment and dispatch of SeTrans and LGE/KU. Furthermore, because of LGE/KU's strong interconnections with MISO, it is extremely unlikely that SeTrans membership would allow capture of the efficiencies of a MISO commitment and dispatch that included LGE/KU. For SeTrans membership to result in any efficiencies at all, LGE/KU would need to be electrically integrated into the SeTrans system through a sizeable long-term firm transmission service contract through TVA – which may be unavailable or available at too high a cost. Without such firm transmission capacity, it will simply not be possible for SeTrans to achieve a lower-cost commitment and dispatch than LGE/KU and SeTrans could achieve as completely separate entities, or that could be achieved with LGE/KU as a MISO member. Furthermore, because of LGE/KU's strong interconnection with MISO, the achievement of an efficient SeTrans commitment and dispatch that included LGE/KU would not address the problem of identifying the cost-reducing and efficiency-enhancing trades between LGE/KU and MISO. In this regard, the SeTrans membership scenario offers no benefits relative to the LGE/KU standalone scenario, and is inferior to the MISO membership scenario.

In addition, this scenario is complicated by the fact that the Day Two market in SeTrans at this point consists of a proposed high-level design. No detailed rules have been worked out. Thus, there will be considerable uncertainty about the effects of a Day Two market implementation on LGE/KU should it choose to participate in the SeTrans RTO.

Within a Kentucky ISO

LGE/KU's membership in a Kentucky ISO would appear to be at least as problematic as membership in the SeTrans RTO, and for many of the same reasons. However, this option does not appear to be a viable contender for three fundamental reasons.

First, a Kentucky state ISO is likely to have costs that are higher on a per-MWh basis than those of MISO. Like MISO and SeTrans, a Kentucky ISO would have to be built from scratch. It is possible that it could be created relatively inexpensively by keeping to a minimal set of functions, so that it did not incorporate the day-ahead market or the locational pricing that are characteristics of FERC's Standard Market Design ("SMD") and prominent features of other RTOs and ISOs. But because day-ahead markets facilitate unit commitment and locational prices help manage transmission congestion, building a "minimal" ISO will come at the cost of reduced operating efficiencies and may ultimately have to give way to a more complete and more expensive ISO design. It is also doubtful that FERC would approve an ISO that did not include a voluntary day-ahead market and locational pricing. Therefore, startup costs and administrative costs of operating a Kentucky ISO would likely be as great as those experienced by the other ISOs and would of necessity be spread over a smaller volume of business, implying a higher cost per unit of business.

Second, Kentucky does not have a transmission system that is internally well integrated. The transmission links between northern Kentucky, southern Kentucky, and eastern Kentucky are relatively weak. In terms of the physics of the transmission system, it makes little sense to draw an ISO boundary at the state line. For the Kentucky grid to be well interconnected would require substantial investments in infrastructure upgrades and expansions that would not necessarily be efficient. Furthermore, the costs of such grid-strengthening investments would have to be recovered from a smaller volume of energy sales and peak load.

Closing Remarks

Considerable uncertainty remains about the short-term and long-term benefits of LGE/KU's three options compared to a continuation of its MISO membership because of the difficulty in quantifying a significant number of the principal factors that drive LGE/KU's relevant administrative, operational and regulatory costs under each scenario. Consequently, we have quantified those factors for which we could obtain reliable information and qualitatively analyzed those factors for which we could not. Nonetheless, the preponderance of evidence leads us to believe the most favorable option for LGE/KU would be to operate as a standalone transmission system. If on the basis of legal analysis it is concluded that the only way LGE/KU can be in compliance with FERC rules is to be a member of an RTO or ISO, the evidence supports a decision to continue as member of MISO. On the basis of the evidence we have examined, neither the SeTrans RTO nor the state ISO options appear to be viable candidates.

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## 9. APPENDIX

Table A.1 provides a side-by-side comparison of all four transmission institutional arrangements in terms of the principal economic factors that we believe could materially influence LGE/KU's decision to remain a member of MISO.

**Table A.1 Relative Advantages and Disadvantages of the Four Options**

| Cost/Benefit Category | MISO Base Case | Standalone System Option | SeTrans Option | Kentucky ISO Option |
|---|---|---|---|---|
| **Off-System Trades** | LGE/KU's short-term trades with its major trading partners are more automated. | LGE/KU must identify its short-term trades. Transmission charges will be a minor barrier to trade. | LGE/KU's potentially greater opportunities for short-term trades with some minor trading partners will be limited by lack of direct interconnection. | LGE/KU must identify its short-term trades. Transmission charges will be a minor barrier to trade. |
| **Transmission Capacity Investments – Quantity** | It is not clear how transmission investments in this case will differ from those of the standalone case. | Transmission upgrades would be as indicated in the 2002 IRP. | This could induce trans-mission links between LGE/KU and SeTrans. | This could induce trans-mission investment within Kentucky. |
| **Transmission Capacity Investments – Cost Share** | LGE/KU may pay for and/or benefit from regional transmission upgrades. | LGE/KU pays for all costs of transmission investments within the LGE/KU system. | The cost sharing policy is not yet determined. | The cost sharing policy is not yet determined. |
| **Access to Transmission** | LGE/KU may have higher priority to transmission service within MISO during emergencies. | LGE/KU may have higher priority to use of its own transmission system during emergencies. | LGE/KU's potentially higher priority to transmission service within SeTrans during emergencies will be limited by lack of direct interconnection. | LGE/KU may have higher priority to transmission service within Kentucky during emergencies. |

| Cost/Benefit Category | MISO Base Case | Standalone System Option | SeTrans Option | Kentucky ISO Option |
|---|---|---|---|---|
| **Allocation of Transmission Rights** | LGE/KU would be allocated a relatively large quantity of FTRs over the external trans-mission systems that are most important to LGE/KU's trades. | LGE/KU would effectively have FTRs for the full capability of its own transmission system. | LGE/KU would be allocated FTRs for the lion's share of its own transmission system capability, plus a small quantity of FTRs over other SeTrans systems. | LGE/KU would be allocated FTRs for the lion's share of its own transmission system capability, plus a small quantity of FTRs over other Kentucky systems. |
| **Transmission Revenues** | Revenue allocation rules have not been fully defined. | Revenues may be slightly lower than in the other cases. | Revenue allocation rules have not been fully defined. | Revenue allocation rules have not been defined. |
| **Payments/Costs for Transmission** | LGE/KU's payments for a postage-stamp access charge could be higher than for a zonal access charge. LGE/KU's share of regional redispatch costs may be affected by MISO membership. | LGE/KU's costs are about equivalent to paying zonal access charges under the MISO option. | LGE/KU would have to purchase access to the TVA system to gain interconnection to SeTrans. LGE/KU might have to pay SeTrans RTORs. | LGE/KU's share of state redis-patch costs may be affected by its membership in a Kentucky ISO. |
| **Reliability and System Planning** | All options are likely to result in a continuation of LGE/KU's history of extremely high reliability. | | | |
| **LGE/KU's Own System Operations Costs** | MISO membership permits reduction in LGE/KU's system operations costs. | LGE/KU's costs would be at historical levels, or possibly higher if LGE/KU undertakes new functions. | SeTrans membership would permit modest reduction in LGE/KU's system operations costs. | Kentucky ISO membership would permit little reduction in LGE/KU's system operations costs. |

| Cost/Benefit Category | MISO Base Case | Standalone System Option | SeTrans Option | Kentucky ISO Option |
|---|---|---|---|---|
| **Share of Market Implementation and Administration Costs** | LGE/KU pays substantial market I&A fees levied on its whole load. | LGE/KU pays market I&A fees only for those transactions with RTOs. | LGE/KU pays substantial market I&A fees levied on its whole load. | LGE/KU might pay even higher market I&A fees than under the other RTO options. |
| **Resource Adequacy Obligation** | All options are likely to result in LGE/KU facing the same state and regional resource adequacy obligations. | | | |
| **Order No. 2000 Implementation Obligation** | Order No. 2000 compliance is mandatory. | LGE/KU will have to be in compliance with Order No. 2000. | Order No. 2000 compliance is mandatory. | A Kentucky ISO would have to conform to Order No. 2000. |
| **Obligation to Pay MISO Exit Fees** | LGE/KU would not pay exit fees. | All non-MISO options require LGE/KU to pay substantial exit fees. | | |