YUNKER & ASSOCIATES

Benjamin D. Allen
P.O. Box 21784
Lexington, KY 40522-1784

859-255-0629
FAX: 859-255-0746
ballen@desuetude.com

November 19, 2004

Drop Box
RECEIVED
NOV 19 2004
PUBLIC SERVICE COMMISSION

Elizabeth O'Donnell, Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: Case No. 2003-00266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Dear Ms. O'Donnell:

Enclosed please find the original copy of the Rebuttal Testimony of Dr. Ronald R. McNamara on behalf of Midwest Independent Transmission System Operator, Inc.

Because this filing is voluminous and we are using the after-hours filing box, we will bring ten (10) copies of these materials to the Commission Monday morning, November 22, 2004.

Copies of Dr. McNamara's rebuttal testimony were served on all parties of record via U.P.S.

Sincerely,

Ben Allen

Benjamin D. Allen

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

Drop Box
RECEIVED
NOV 19 2004
PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	)))))	CASE NO. 2003-00266

Rebuttal Testimony of

<u>Dr. Ronald R. McNamara</u>

Vice President of Market Management

Midwest Independent Transmission System Operator, Inc.

Filed: November 19, 2004

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald R. McNamara. I work at 701 City Center Drive, Carmel, Indiana 46032.

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

A. I am employed as Vice President of Market Management for the Midwest Independent Transmission System Operator, Inc. (the "Midwest ISO").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of California, Irvine with a B.A. degree in Economics and a B.A. degree in Social Ecology in 1979. I received an M.A. degree and Ph.D. in Economics from the University of California, Davis in 1991 and 1993, respectively. As an economist, I have worked in academia as well as in both the public and private sectors. From 1995 to 1998, as the Manager of Research and Development for the Electricity Market Company Ltd., and as a Senior Advisor for Putnam, Hayes and Bartlett Asia-Pacific, I was involved in designing and implementing the electricity market in New Zealand. I have also worked for the Queensland (Australia) state regulatory commission, Duke Energy as the General Manager of Regulatory Affairs (Australia), Enron, and, most recently prior to joining the Midwest ISO, I was employed at American Electric Power.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES WITH THE MIDWEST ISO AS THEY RELATE TO THIS FILING.

A. I am the Midwest ISO Officer responsible for the Tariff and for Market Design. In this capacity, it is my responsibility to ensure that the Midwest ISO's markets facilitate enhanced reliability, are designed correctly, and operate efficiently.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. The Kentucky Public Service Commission ("Kentucky PSC") initiated this proceeding to consider the merits of having certain Kentucky utilities remain members of the Midwest ISO, the Regional Transmission Organization ("RTO") responsible for assuring reliable operations and efficient wholesale markets for a large part of the interconnected Midwest electricity system. In their testimony, witnesses for Louisville Gas and Electricity Company and Kentucky Utilities ("LG&E/KU") have questioned whether remaining in the Midwest ISO will be in the public interest and a benefit to Kentucky.[1] My testimony addresses those questions and provides the results of further analyses done by the Midwest ISO under my direction. My testimony confirms that there will indeed be significant net economic and reliability benefits to Kentucky if the utilities remain within the RTO rather than attempt to function in today's highly interconnected transmission system on a "stand-alone" basis or under the alternative arrangements suggested by LG&E/KU.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides support for precisely the same conclusions presented to the Kentucky PSC in my Direct Testimony of December 29, 2003. That is, (1) there are substantial reliability and economic benefits that will accrue to LG&E/KU from their continued membership in the Midwest ISO, (2) the authority of the Kentucky PSC to set rates for end-use customers is not in any way diminished, and (3) relative to current practices, the use of a regional security constrained economic dispatch to redispatch generation facilities to solve transmission constraints is more efficient.

---

[1] In addition to the testimony of witnesses for LG&E/KU, I will be responding to the (1) Supplemental Testimony of Paul W. Thompson, (2) Testimony of Susan F. Tierney, Ph.D., (3) Supplemental Testimony of Mark S. Johnson, (4) Supplemental Testimony of Martyn Gallus, (5) Supplemental Testimony of Michael S. Beer, (6) Supplemental Testimony of Matthew J. Morey (and Investigation with Laurence D. Kirsch), all filed on September 29, 2004.

In arriving at these conclusions, I acknowledge that when LG&E/KU becomes part of the Midwest ISO's larger and more precise regional security constrained economic dispatch process there will be a change from the current practices used by LG&E/KU. Presumably, following the merger of LG&E and KU, operational efficiencies, including the benefits of joint dispatch were realized, *i.e.*, there was a change in the way in which the combined generation portfolio was operated as compared to when the companies were separate. If two companies can realize reliability and efficiency gains from more closely coordinating their actions, it makes sense that closer coordination at the regional level will provide additional improvements in reliability and efficiency. The regional coordination mechanism that will be implemented under the Open Access Transmission and Energy Markets Tariff ("EMT") allows for a greater degree of coordination – including improvements in reliability and economic efficiency – across a larger region without a merger or any loss or relinquishment of effective control.

While I address how LG&E/KU can continue to operate as they do today, the real question is why they would want to forego the potential gains that exist from being part of a more efficient coordination process. The discussion of this inherently complex issue has been made even more difficult by a number of misconceptions. The direct question under consideration in this proceeding is whether or not the continued membership of LG&E/KU in the Midwest ISO benefits Kentucky. In order to effectively address that question, we must first determine whether or not the current practice used to coordinate real time power flows (*i.e.,* local dispatch) is as reliable, efficient and precise as it could be. The answer to that question is unambiguously no. My emphasis on the dispatch process is intentional and stands in stark contrast to other discussion points raised in this proceeding. Heretofore, the dispatch process itself has received little attention in most regulatory proceedings. However, it is a core capability under the EMT and is, therefore, central to this proceeding. As such, my testimony, in contrast to that provided by

LG&E/KU, has consistently focused on both the benefits achieved from centralizing the dispatch function and on contrasting the existing coordination mechanism with what will be implemented on March 1, 2005.

Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS WITH RESPECT TO THE BENEFITS AND COSTS OF LG&E/KU CONTINUING TO PARTICIPATE IN THE MIDWEST ISO AFTER IMPLEMENTATION OF THE EMT IN COMPARISON TO OTHER OPTIONS THAT MAY BE AVAILABLE TO THE COMPANIES?

A. LG&E/KU occupy a unique position in the middle of the transmission grid for eastern North America. The LG&E/KU system includes transmission elements that regularly constrain interregional power flows. As a result, extending regional congestion management to the LG&E/KU system creates significant economic gains. If they participate in the Midwest ISO's regional economic dispatch and energy markets, LG&E/KU and their customers will benefit from the resulting efficiency improvements.

When compared to continued participation in the Midwest ISO, if the Companies withdraw to pursue the Transmission Owner – Reliability Coordinator ("TORC") option, LG&E/KU and their customers can expect a net annual increase in their costs of service, after deducting the costs for the EMT implementation, of $43.9 million per year. Taking into account both these recurring costs and the additional exit fee of $40.2 million which LG&E/KU would have to pay to withdraw effective January 1, 2006 – the earliest date on which they could withdraw under the Midwest ISO Transmission Owners' Agreement – leaving the Midwest ISO could cost LG&E/KU customers $303.6 million in additional costs and foregone benefits over the period 2005 through 2010. The present value of these near term economic impacts is $264.1 million. In Part VII of my testimony, I explain the analysis that was performed, including sensitivity cases.

Q. DOES YOUR TESTIMONY ALSO RESPOND TO ISSUES RAISED BY LG&E/KU WITH RESPECT TO THE OPERATION OF THE MIDWEST ISO'S ENERGY MARKET TARIFF?

A. Yes. In my Direct testimony filed December 29, 2003, and my Supplemental Testimony filed September 29, 2004, I described the functions that the Midwest ISO will perform when it begins "Day-2" operations in the spring of 2005, and what those functions will mean for utilities and their customers in Kentucky. In particular, I described (1) how the implementation of a regional, security-constrained, economic dispatch and other reliability functions by the Midwest ISO will improve the day-to-day reliability of electricity operations in this region, compared to current procedures and stand-alone operations, and (2) how that dispatch and related market functions will improve the opportunities for Kentucky utilities to serve their customers at lower costs. I will return to those explanations where necessary to rebut comments and misconceptions that appear in the LG&E/KU testimony about participation in the Midwest ISO and the operation of the Midwest ISO EMT.

Q. WHAT ARE THE PRINCIPAL MISCONCEPTIONS IN THE LG&E/KU TESTIMONY ABOUT THE EMT AND HOW IT AFFECTS LG&E, KENTUCKY, AND ITS ELECTRICITY CONSUMERS?

A. There are numerous misconceptions in the LG&E/KU testimony, but they can be boiled down to a few basic misunderstandings of how the EMT works to ensure reliability and promote efficient operations and trading. To summarize:

- LG&E/KU claims that it will lose control over how it utilizes its own generation sources to serve its own customer loads and how it arranges and schedules beneficial trades.[2] Part II of my testimony shows that under the EMT, LG&E/KU retains all the control it needs to ensure that its own low-cost resources are

---

[2] *See*, *e.g.*, Thompson supplemental testimony at 3; Gallus supplemental testimony at 13-14.

available to serve LG&E/KU and Kentucky customer loads and all the flexibility it needs to arrange and carry out off-system sales to other utilities and markets. Further, I explain that under the EMT, reliability will be improved throughout Kentucky as a result of Midwest ISO's regional, security-constrained, economic dispatch. Because of the open and transparent regional markets this dispatch will facilitate, LG&E/KU will have enhanced opportunities to serve its customers at even lower cost and enhanced opportunities to make beneficial trades with others throughout the Midwest ISO region.

- LG&E/KU next claims that as a result of losing control over its own resources (an assumption I show to be unfounded), LG&E/KU will be forced to serve other utilities' loads at the expense of LG&E/KU customers and LG&E/KU customers might therefore face higher costs that translate to higher retail rates.[3] Part III of my testimony shows that under the EMT, LG&E/KU and its customers will actually benefit from the regional economic dispatch and regional sharing of operating reserves. The EMT will, at the least, preserve - and more likely improve - LG&E/KU's ability to provide low-cost service to Kentucky consumers.
- LG&E/KU then claims that if it loses flexibility and control to the Midwest ISO, then the Kentucky PSC will also lose regulatory control and influence over the rates and other conditions under which Kentucky retail customers are served.[4] Part IV of my testimony shows why this concern is misplaced, because the EMT does nothing to undermine how Kentucky (or any other state) sets *retail* rates or the terms and conditions of *retail* service. Instead, the EMT will support Kentucky efforts to keep retail rates at some of the lowest rates in the nation. The

---

[3] *See, e.g.,* Beer supplemental testimony.

[4] *See, e.g., id.*

EMT will facilitate a more efficient *wholesale* market and virtually eliminate existing barriers to Kentucky utilities' access to a larger regional *wholesale* market. In addition, the Kentucky PSC will gain a forum — the Organization of Midwest ISO States -- and a voice in the resolution of regional planning, reliability and grid expansion issues that it would not have but for the Midwest ISO.

- LG&E/KU also argues that the system of locational marginal pricing and financial transmission rights that will be implemented under the EMT will increase congestion and/or its costs and increase the risks LG&E/KU faces in serving its loads.[5] Part V of my testimony explains why these concerns are unfounded. Each Locational Marginal Price ("LMP") will make transparent the marginal costs of managing congestion that is already present on the existing grid, while FTRs will provide a flexible mechanism for hedging congestion costs without undermining the benefits of economic dispatch.
- LG&E/KU claims that any reliability and other regional coordination benefits that LG&E/KU might achieve if LG&E/KU remains a part of the Midwest ISO could also be achieved either through "stand-alone" operations or through better coordination with (or participation in) some other regional entity, such as TVA or the Southwest Power Pool.[6] Part VI of my testimony explains why it is not likely that LG&E/KU can gain the economic and reliability benefits of a regional, security-constrained economic dispatch, regional reserve sharing, and better access to regional markets from these other entities unless they too provided the same functionality as the Midwest ISO (which they are not currently planning to do) and unless LG&E/KU became a full participant in those regionally

---

[5] *See, e.g.,* Gallus supplemental testimony at 19.

[6] *See, e.g.,* Beer supplemental testimony at 18; Johnson supplemental testimony at 3.

coordinated functions (which it has not proposed to do). Moreover, none of these suggested "alternatives" is specified or explained in any significant detail. LG&E/KU has not shown how these alternatives could provide benefits and functionality comparable to participating in the Midwest ISO. There is no showing that these "alternatives" could improve reliability, reduce barriers to transmission access or enhance efficient wholesale trading in the highly interconnected regional grid of which Kentucky is a part, or how they could achieve "transmission compliance"[7] with requirements of the Federal Energy Regulatory Commission.

Thus, the basic claims made by LG&E/KU about how the EMT would operate and how it would affect LG&E/KU, its customers and the State are simply not correct.

Q. ARE THERE BENEFITS FOR KENTUCKY UNDER THE EMT?

Yes, under the EMT, full participation in the Midwest ISO will have the following reliability, economic and regulatory benefits for Kentucky:

A. Reliability benefits to Kentucky and the regional grid

- Provide a regional security-constrained economic dispatch to manage congestion and loop flows through Kentucky and the wider region;
- Displace uncertain, disruptive and time-consuming transmission loading relief ("TLR") curtailments with regional five-minute dispatch to ensure flows remain within operating security limits;
- Effectively monitor the grid region wide to detect and quickly solve local problems before they become more severe (or catastrophic) regional problems;
- More effectively coordinate flows between utility systems within the regional footprint; and

[7] The phrase "transmission compliance" is one used repeatedly by Dr. Tierney, but it is never defined.

- Through the regional dispatch, allow transmission to operate closer to security limits while providing regional monitoring and dispatch to ensure flows stay within safe operating security limits.

B. Economic benefits to Kentucky

- Allow LG&E/KU and other low-cost utilities to control their own generation to ensure their loads are served at the lowest cost;
- Provide a regional economic dispatch to minimize the costs of serving load across the region;
- Through regional economic dispatch, enhance and make transparent LG&E/KU's opportunities to serve its customers at lower costs, as when it is cheaper to purchase energy from the regional dispatch than to use LG&E/KU's own plants;
- Through regional economic dispatch, enhance LG&E/KU's opportunities to make profitable off-system sales throughout the regional market;
- By replacing TLR curtailments with regional dispatch, allow more schedules to be safely accommodated and more efficient use of the regional grid;
- Provide access to day-ahead and real-time balancing markets to support LG&E/KU schedules and reduce risks;
- Reduce costs of resource adequacy through regional reserve sharing and more effective use of the interties between utilities; and
- Reduce regional trading barriers by eliminating through-and-out and other pancaked transmission rates, giving Kentucky improved access to regional markets.

C. Regulatory benefits to the Kentucky PSC

- Provide efficient and transparent price signals about the value of investments in generation and demand-side options at different locations;

- Provide efficient and transparent price signals about the cost-effectiveness of transmission upgrades that reduce congestion;
- Provide a regional planning forum to determine regional needs and cost allocation for transmission expansion;
- Provide independent regional monitoring and mitigation of market power; and
- Allow Kentucky to preserve the priority Kentucky has historically (and by statute) maintained for serving native loads.

None of LG&E/KU's suggested alternatives to participation in the Midwest ISO has been adequately defined and none is likely to achieve anything close to these same benefits without at least mimicking the Midwest ISO's regional functions and EMT provisions and then coordinating those functions with the Midwest ISO to gain open access to the Midwest grid and its markets.

Q. WHY ARE THE MIDWEST ISO/RTO'S REGIONAL CAPABILITIES IMPORTANT TO KENTUCKY?

A. The two most important purposes for an RTO are (1) to ensure reliable operations across the entire interregional grid, and (2) to solve the difficult problem of how to provide open, non-discriminatory access to the nation's transmission systems consistent with reliable operations. Providing a regionally optimized, security-constrained, economic dispatch is the key to solving both problems. A regional dispatch manages congestion and regional loop flows more reliably and efficiently than TLRs, while providing balancing and other ancillary services to support improved transmission access and wholesale trading. Providing open, non-discriminatory access to this dispatch (and to the spot/balancing markets that derive from the dispatch) and pricing the dispatch efficiently are an effective, proven approach to providing open, non-discriminatory access to transmission. While the Midwest ISO has endeavored to provide open access to the regional grid since it began Day-1 operations, I believe that the EMT features will provide a more effective way to eliminate barriers to open access and enhance interregional trading, while dealing efficiently with regional loop flows, congestion and other transmission constraints. Moreover, experience has also shown that these regional dispatch tools are becoming increasingly necessary to ensure reliable grid operations.

Q. WHY ARE THESE REGIONAL FUNCTIONS AND TOOLS NECESSARY TO ENSURE RELIABLE GRID OPERATIONS?

A. Today's transmission systems have become highly interconnected and require much greater regional coordination than was true in the past. The Eastern Interconnection, of which the Kentucky utilities are a small part, functions as one huge, interconnected machine and must be operated as such, creating an absolute necessity for regional and interregional coordination of this vast network of interstate transmission and interconnected generation. But today's structure relies heavily on outmoded arrangements run by local utilities and numerous local control areas (36 separate control areas in the Midwest ISO footprint alone). The huge and costly blackout that occurred in the upper Midwest and Northeast in August 2003 was a warning sign that the current balkanized transmission control structure is no longer up to the task, whether or not NERC "reliability standards" become mandatory. The current control system must be modernized as we transition to regional institutions, regional grid monitoring tools and regional dispatch and coordination rules that can "see" and operate the grid as the single interconnected machine that it is.

In seeking to remain a stand-alone utility, LG&E/KU's witnesses would have the Kentucky PSC ignore the need for greater regional coordination. They implicitly ask the Kentucky PSC to believe that the local and still balkanized approaches of the past will continue to ensure reliable and efficient operations in the future, just as they once did when the grid was only loosely interconnected, when interregional transactions were limited, and when operational problems in one area could be locally solved and have little or no effect on surrounding systems. But with today's highly interconnected systems, operations in any small part of the grid necessarily affect flows and reliability across a huge interstate region. The localized grid monitoring, scheduling, dispatch and coordination tools used by local utilities can "see" and affect only a tiny portion of the grid and cannot monitor the effects they have on others nor easily control the effects others have on their local systems. The blackout of August 2003 proved that a myopic view of reliability is no longer adequate, because unresolved problems in one small part of the grid can very quickly put the lights out across huge regions.

The Commonwealth of Kentucky and the Kentucky PSC have already shown that they understand the need to move to a more regional framework for managing the grid and ensuring reliable electricity service for Kentucky citizens. They have shown this by supporting the development of RTOs to promote regional reliability and improved access to regional markets, and by approving the participation of AEP-Kentucky Power in PJM. Exactly the same arguments apply with equal force and logic to transmission systems owned by LG&E/KU. The Midwest ISO's EMT will provide essentially the same regional functionality as PJM, and the unprecedented Joint Operating Agreement between PJM and Midwest ISO will ensure more efficient, reliable, and regionally coordinated operations between the two RTOs, while laying the foundation for a coordinated interregional dispatch and common market across the Midwest and Mid-Atlantic regions.

Q. IS PARTICIPATION IN THE MIDWEST RTO'S REGIONAL FUNCTIONS IMPORTANT TO KENTUCKY'S ECONOMIC SUCCESS?

A. Yes. I believe that Kentucky fundamentally understands that its economic future depends importantly on its ability to remain competitive. For the electricity sector, Kentucky must not only serve its own consumers and industries at the lowest possible cost but also retain its competitive advantage within the context of larger regional markets. Kentucky is a low-cost producer, but to realize this advantage, Kentucky needs access to markets that are beyond the LG&E/KU service area and Kentucky's borders. Kentucky understands that its ability to access these broader markets depends on open access to the interconnected transmission systems beyond its own borders and the elimination of barriers to interregional trading. These benefits can only come from participation in an independent RTO that is structured and dedicated to providing the regional mechanisms necessary to achieve reliable grid operations, ensure least-cost regional dispatch and support efficient trading.

LG&E/KU would have the Kentucky PSC believe that functioning on a stand-alone basis, LG&E/KU would have the same access to regional markets as a participant within the RTO. The Kentucky PSC is thus asked to believe that Kentucky can achieve the lowest cost of serving its own loads without being part of a larger regional dispatch and without gaining unrestricted access to a huge market that can draw on low-cost resources across the entire region. Intuitively, the Kentucky PSC must realize that these arguments are simply not credible. There is no practical way for LG&E/KU and Kentucky to gain the full benefits of access to wider regional markets without participating directly in the regional institutions and mechanisms that make such access possible.[8]

The Kentucky PSC should, therefore, not be misled by arguments that LG&E/KU can continue to function much as it has in the past, or make only cosmetic adjustments, such as asking an independent entity or TVA (instead of Midwest ISO) to be the "reliability coordinator" for the LG&E/KU transmission system. This complacency will not serve Kentucky's need to remain competitive in large regional markets that will be opened by RTOs. Nor does it serve Kentucky's interests for LG&E/KU to hold out a

[8] Even if it were possible, it seems unrealistic to expect other RTO member states and utilities to allow a non-member, stand-alone utility to "free-ride" on the benefits created by the RTO without charging an access fee that would compensate the members for the benefits for which they paid their fair share.

vague, noncommittal interest in joining the Southwest Power Pool, a nascent RTO that is both distant from Kentucky and may be years away from providing Order No. 2003 compliant regional dispatch, monitoring and grid coordination functions that Midwest ISO has already installed and will fully implement next spring. Instead, the Kentucky PSC should conclude that keeping LG&E/KU and its transmission system in the Midwest ISO/RTO is in the public interest and will keep Kentucky moving in the right direction, while fully preserving Kentucky's enviable position of being one of the lowest cost electricity systems in the country.

Q. SHOULD THE KENTUCKY PSC ALSO BE CONCERNED ABOUT THE LOSS OF TRANSPARENCY AND INDEPENDENT OPERATIONS IF LG&E/KU'S TRANSMISSION AND DISPATCH OPERATIONS FUNCTION ON A STAND-ALONE BASIS?

A. Yes. The RTO's least-cost dispatch and unbiased scheduling processes will offer all parties truly non-discriminatory access to a huge interconnected transmission system, while improving access to a huge interstate market. The RTO is also an independent entity fully committed to the broad public interest, not the narrow interests of any competitor or its marketing affiliates. No stand-alone utility can make these claims for its own operations; local dispatch operations are seldom open, and almost never transparent.[9] The Kentucky PSC simply cannot know, and cannot get the information to determine, whether its utilities' local dispatches are truly least cost or whether they miss opportunities to purchase power from others at lower cost and miss opportunities to make

---

[9] The dispatch function is critical to assuring open, non-discriminatory access to the interconnected transmission system. The need to have this function performed in an unbiased and efficient manner was a principal reason for creating *Independent* System Operators for each region. *See*, *Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services By Public Utilities*, Order No. 888, 1991-96 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 at 31,682 (1996), *order on reh'g*, Order No. 888-A, III FERC Stats. & Regs., Regs. Preambles ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC,* 152 L. Ed. 2d 47, 122 S. Ct. 1012 (2002).

economic off-system sales to others. Nor can the Kentucky PSC determine whether this dispatch (and the effect dispatch decisions have on available transmission capacity) is being used to favor an affiliate's trades over a competitor's trades, even though it raises the cost of serving local loads. The RTO's economic dispatch will function at least cost, and its results and prices will be auditable and transparent to state commissions and participants alike.

II. The Midwest ISO EMT Will Not Unreasonably Restrict The Kentucky Utilities' Flexibility And Control Over Their Own Resources To Serve Their Own Loads. The EMT Will Instead Increase Their Options And Preserve Or Enhance Their Ability To Serve Those Loads At The Lowest Cost.

Q. IS LG&E/KU CORRECT IN CLAIMING THAT, UNDER THE MIDWEST ISO EMT, KENTUCKY UTILITIES WILL LOSE FLEXIBILITY OR CONTROL OVER THEIR OWN RESOURCES AND THUS UNDERMINE THEIR ABILITY TO SERVE THEIR OWN LOADS AT LOWEST COST?

A. No. Much of LG&E/KU's discussion of this subject (*see, e.g.,* Supplemental Testimony of Paul Thompson, page 6; Supplemental Testimony of Mark Johnson, pages 11-16; Supplemental Testimony of Michael Beer) is a misunderstanding of how vertically integrated utilities can and probably would function under the EMT. There are many facets of this confusion, and I address the major misconceptions below.

Q. DOES LG&E/KU HAVE UNFETTERED DISCRETION ABOUT HOW IT USES ITS OWN RESOURCES TODAY?

A. No. LG&E/KU is subject to transmission thermal, voltage and stability limits, regional loop flows over which it has little or no control, and other network realities that force it to redispatch its own generation out of economic merit order. These same constraints must be honored by the Midwest ISO to ensure reliable operations. The laws of physics do not permit LG&E/KU to operate its own plants any way it chooses. The reality is that all energy injections anywhere on the interconnected system become part of the "pool" of energy that must be coordinated and dispatched at every moment to maintain system balance while keeping flows across the system within operating security constraints. This is true today, and will continue to be the case under the EMT. When the EMT sets requirements for how LG&E/KU and other generators interact with the Midwest ISO system operators, the EMT is merely recognizing the strict demands of these network realities. Once these realities are respected, the EMT is structured to give utilities and other generation owners maximum flexibility in how they use their own resources to serve their own loads.

Q. HOW WOULD YOU CHARACTERIZE LG&E/KU'S MISREADING OF THE EMT PROVISIONS WITH RESPECT TO CONTROLLING GENERATION?

A. The underlying premise of LG&E/KU's assertions is that utilities functioning under the EMT cede control over scheduling and dispatch of their generation plants to the Midwest ISO, which LG&E/KU asserts would function like a "mandatory" power pool. The false image LG&E/KU testimony creates is that the plant owners would have little or no discretion over when and how much their plants run and no control over whose loads they serve. Moreover, the description suggests that a utility with an obligation to serve its own loads would lose the ability to ensure that the lowest-cost resources available to the utility were available to serve its own loads and that the utility would not be able to hold its own plants in reserve in the event of contingencies, such as a sudden plant failure or an unexpected rise in customer demand. As a result, LG&E/KU implies its customers would be forced to purchase power at higher cost in the Midwest ISO spot markets, and there is even a suggestion that LG&E/KU loads might not be served because LG&E/KU

resources had all been dispatched or controlled by the Midwest ISO to meet some other utilities' loads.[10] Every one of these assertions and suggestions is simply false.

The reality is that the EMT will (1) allow LG&E/KU to use its own low-cost resources to serve its own resources, *and* (2) also allow LG&E/KU to rely on the ISO's day-ahead and real-time energy markets to serve its loads at even lower costs when other resources can serve those loads at costs less than LG&E/KU's generation costs. In other words, the EMT markets will expand LG&E/KU's options for providing low-cost service, rather than reduce them.

Q. DO THE PROVISIONS OF THE EMT CREATE A "MANDATORY" POOL IN WHICH GENERATION OWNERS LOSE CONTROL OVER HOW THEIR UNITS ARE OPERATED?

A. No. Participation in the RTO's dispatch and the energy markets that derive from this dispatch is essentially *voluntary*.[11] Under the EMT, generators have several choices in how they exercise control over the operation of their own plants.

First, generators within the Midwest ISO footprint can choose to offer their generation *or not* to the ISO for use in the ISO's security-constrained economic dispatch.[12] If they choose to offer any portion of their plants' output, that portion is subject to ISO dispatch instructions, just as it would be subject to utility dispatch instructions if the plant were available to the utility dispatch. If the utility/owners choose

---

10 *See, e.g.,* Beer supplemental testimony at 8-9.

11 This implies that in theory, all generators could voluntarily decline to participate in the dispatch, leaving the ISO with no flexible plants to dispatch up or down, a condition that would prevent the ISO from balancing the system and managing congestion. But in practice, as shown by how other ISOs function with features like the EMT, reliability is easily maintained, because the price signals used by the ISO to price the dispatch (LMP) strongly encourage generators to (1) be dispatchable and (2) follow the ISO's dispatch instructions. In ISOs with EMT-like provisions, generators quickly learn that if their units can be dispatched, it is almost always economically advantageous to offer to be dispatched. For some plants, such as nuclear units, dispatch is impractical or unsafe, so they are usually self scheduled. After accounting for these non-dispatchable units, there are enough voluntarily dispatchable units to balance the system and manage congestion reliably and efficiently.

12 *See* EMT § 38.3.

not to offer a plant's output for dispatch, the plant is not subject to ISO dispatch except under extreme emergency conditions threatening grid reliability, just as such plants would be subject to emergency instructions if the critical reliability function resided with local control area dispatchers.[13] *See generally*, EMT § 38.1.1g.

Second, even if a generator chooses to be subject to ISO dispatch, it can strongly affect how and when it will be dispatched by the ISO by defining the offer prices and operating conditions for each level of output.[14] For example, a plant that would prefer not to be dispatched except in exceptional circumstances (such as near shortage conditions) could, under the EMT, offer its output at very high offer prices, thus ensuring that it would not be dispatched unless actual shortage conditions pushed spot prices to very high levels at or above the unit's offer price. The essential point is that the EMT allows the generation owner to define the terms and conditions under which its plants will be dispatched. Once it has this information from the generator, the ISO can then optimize a reliable and economic dispatch in a way that is consistent with the generator's wishes, as expressed in the offer terms. *See generally*, EMT § 39.2.5.

Third, generators are free to submit bilateral schedules – indicating the hours and amounts of desired output – that are not subject to the ISO's dispatch. *See generally*, EMT §§ 39.1.3 and 39.1.4.

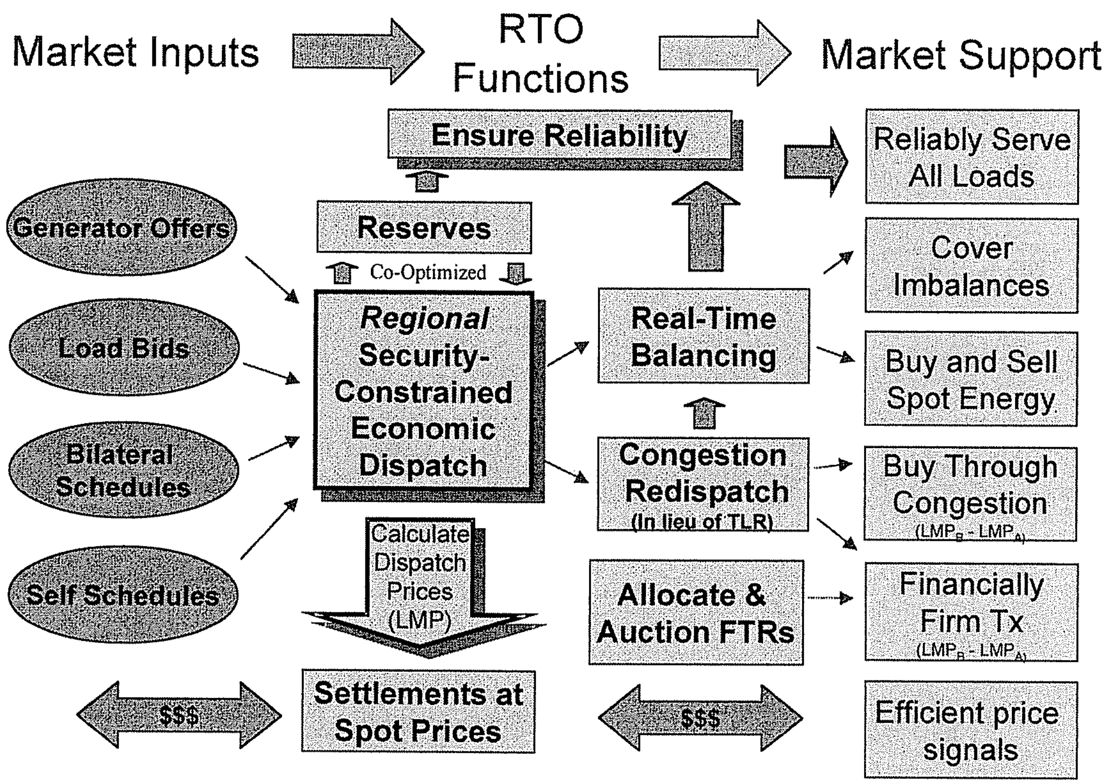
Fourth, generators may choose to "self-schedule" their plants to operate at the times and the outputs they choose and not be subject to ISO dispatch. *See generally*, EMT § 39.1.2. Each of these options is depicted along the left-hand side of the following picture.

---

[13] Importantly, moving the critical function of security-constrained, economic dispatch from the local control area level to the regional level, as the EMT will do, and supporting that dispatch through the ISO's inter-regional grid monitoring system, will enhance reliability, reduce the likelihood of emergency conditions, and increase the ability of the region to respond effectively to emergencies if and when they arise.

[14] A single generating unit's "offer" can consist of up to ten pairs of (MW) output and ($/MWh) prices, creating, in effect, a supply curve for the entire output of the plant. The generator is largely free to set the output and prices for each pair, subject only to limits that might indicate an effort to exercise market power.

Regional Security-Constrained Economic Dispatch Enhances Reliability & Creates Spot Markets



Q. DOES THIS STRUCTURE CREATE A VOLUNTARY SPOT MARKET?

A. Yes. An open, voluntary spot market arises as a natural consequence of having the RTO coordinate a regional, bid-based economic dispatch. The spot market arises logically from allowing generators and loads to offer/bid into the ISO's economic dispatch and from the necessity of paying generators for the energy they provide to the ISO's economic dispatch and charging loads for the energy they purchase through that dispatch. To do this, the ISO must determine the value of energy at each location where it might be injected and/or withdrawn and pay or charge participants the correct value.

This value is defined as the LMP, which reflects the marginal cost of serving an increment of load (1 MW) at each location on the grid, given the offers and bids from generators and loads, the actual dispatch for that interval, and the transmission constraints that were binding during that interval. Generators receive the LMP at their location for the energy they sell into this dispatch/spot market, and loads pay the LMP at their locations (or an average of the LMPs for a load region) for any purchases they make from this dispatch/spot market. Parties with imbalances pay or receive the LMP for their respective locations to reflect the value of the imbalance energy. Parties that choose to buy or sell spot energy pay or receive the LMP for their respective locations.

Q. IS LG&E/KU CORRECT IN SUGGESTING THAT THE MIDWEST ISO DEPARTED FROM ITS CORE FUNCTIONS OF TRANSMISSION OPERATIONS AND RELIABILITY WHEN IT CHOSE TO COORDINATE REGIONAL SPOT MARKETS?

A. No. The regional spot market arises of necessity from the same process that the ISO uses to ensure reliable operations. That is, the spot market arises from the regional, security-constrained, economic dispatch and the practical necessity to pay and charge parties for the energy they inject and withdraw through that dispatch and to charge them for the costs of the redispatch needed to accommodate their transmission schedules and keep flows within safe operating security limits. Furthermore, LMP prices used for settlement (1) are derived from and consistent with this reliable dispatch and (2) provide the correct incentives for generators to follow dispatch instructions. The spot market thus supports reliability, just as the reliability mechanism creates the spot market. That is why it is not correct to view operating the "spot market" and "reliability" as separate functions that could be administered by separate entities, even though parts of LG&E/KU's testimony – *e.g.*, its discussion of alternatives to RTO participation – implicitly assume that reliability functions could be broken apart with pieces provided by LG&E/KU and others by some alternative entity, while market operations could be handled in some other unspecified way.[15] The two cannot logically or practically be separated and still function well.

Q. DOES THE EMT FORCE UTILITIES TO PARTICIPATE IN THE MIDWEST ISO ENERGY SPOT MARKETS, AS LG&E/KU SUGGESTS?

A. No. Under the EMT, "participation" in the day-ahead and real-time energy markets is voluntary. Participation means that the generator/seller sells energy in the ISO's day-ahead or real-time markets and is paid for its quantities at the LMP at its location. For a load or buyer, participation means that the load/buyer purchases energy in the day-ahead or real-time markets and is charged for the purchased quantities at the LMP for its location (or more likely, a weighted average of the LMPs in the LG&E/KU pricing area). No entity is forced to participate in these markets if it covers its own loads with its own resources or with resources scheduled through a bilateral contract. Under the EMT, utilities and other load-serving entities are free to use their own generation and/or bilateral contracts to serve as much or as little of their load obligations as they choose, and rely on the spot markets only for the residual not covered by their own or contracted resources. *See generally*, EMT §§ 39.1.2 through 39.1.4. (In the picture above, these options are illustrated in the boxes "Cover Imbalances" and "Buy and Sell Spot Energy.")

Q. IS A UTILITY THAT ELECTS TO SCHEDULE A BILATERAL OR SELF SCHEDULE ITS OWN GENERATION TO MEET ITS OWN LOADS REQUIRED TO "SETTLE" ITS TRANSACTIONS IN THE MIDWEST ISO SETTLEMENT SYSTEM?

---

[15] *See, e.g.*, Beer supplemental testimony at 15, where he cites the Commission's initial AEP order to the effect that:

> "RTOs were intended to be independent bodies with functional control over utility transmission systems. If MISO sought only to continue to supply reliability-enhancing services, then MISO's objectives and the Commission's RTO policy would align...."

I submit that the Midwest ISO has steadfastly adhered to this reliability/transmission emphasis because the regional markets flow naturally from reliable dispatch and are designed to support and enhance reliable and efficient transmission operations.

A. Yes, but not in a way that forces them to participate in the spot markets. Scheduling parties participate in the ISO settlements so that the ISO can properly charge them for transmission losses and congestion associated with their schedules and so the ISO can properly charge or credit them for any imbalances (*e.g.*, deviations from their schedules). To make the settlement accounting complete, all injections and withdrawals must be accounted for. In the case of bilaterals and self-schedules, injection quantities are credited at their respective LMPs and withdrawal quantities are debited at their respective LMPs. *See generally*, EMT §§ 40.4 and 40.4.2. Putting losses aside for the moment, for the energy associated directly with balanced bilaterals and self-schedules, the quantity amounts net out to zero. For a self-scheduling entity, the netting out to zero means that the entity's load is served at the cost of the entity's generator, no matter what the ISO's spot market price may be. For a bilateral transaction, the netting out to zero means that the load is served at the bilateral contract price, no matter what the ISO's spot market price may be. Of course, if the parties do not follow their schedules, any deviations or imbalances amount to either purchases of energy from or sales of energy to the ISO markets, and so these quantities must be settled at the spot market LMPs where the deviations/imbalances occur. To that limited extent only, the parties participate in the spot market.

Q. HOW ARE BILATERALS AND SELF SCHEDULES CHARGED FOR LOSSES?

A. The LMP prices contain an energy component, a marginal losses component, and a congestion component. Under any system, parties that use the grid must either provide or pay for the losses associated with their transactions. Under the EMT, parties can either purchase the energy associated with supplying the losses or they can "self-provide" losses by generating extra energy. In the latter case, the party is credited for this energy's value through the LMP market settlements. Under non-LMP systems, parties tend to pay approximations of "average" losses that seldom reflect the marginal impact of their transactions on the system and thus send the wrong price signals about dispatch, operations and investment. Under LMP, scheduling parties will pay the marginal cost of losses associated with their schedules. Charging for losses in this way sends the correct economic signal about the marginal costs that each transaction imposes on the system. It thus provides an important incentive for efficient dispatch, efficient operations, and efficient investment decisions.

Q. DOES THE EMT'S USE OF MARGINAL LOSSES FORCE UTILITIES TO PAY MORE FOR LOSSES THAN THEY DO TODAY?

A. On balance, no. Marginal losses tend to be higher than average losses, so when the Midwest ISO charges for marginal losses, it will collect a surplus over what it actually costs to provide the actual losses on the system. In the initial settlements, the amounts charged for marginal losses will exceed the amounts paid out to those who supply the actual losses. This surplus will then be refunded to LG&E/KU and other LSEs on a *pro rata* basis. *See generally*, EMT § 40.6. Under the EMT, LG&E/KU and other utilities in each area will receive (in monthly settlements) a rebate of the difference between the amount charged for marginal losses and the amount charged for average losses, so that over time, LG&E/KU and its customers will in effect pay for average losses, just as they do now. The effect of charging marginal losses for each transaction in the daily settlements, while rebating the surplus back to utilities, will be to preserve efficient price signals for real-time operations while not overcharging the utilities and their customers. The marginal cost signals will tend to encourage generators to invest at locations that reduce losses, thus tending to lower costs of serving loads over time.

Q. HOW DOES THE EMT CHARGE AND SETTLE PARTIES FOR THEIR CONTRIBUTIONS TO CONGESTION?

A. The EMT settlements are based on LMPs, which contain a congestion component (as well as an energy component and marginal losses component). Parties are charged (or paid) for the marginal redispatch costs (or savings) associated with each transaction. Ignoring losses, the bid-based cost of any redispatch that is needed to accommodate each transaction is equal to the difference between the LMP at the sink and the LMP at the source. The difference between the congestion component of the LMP at the sink and the congestion component of the LMP at the source is the congestion charge (or credit). When a party schedules a transaction between location A and location B, the EMT settlements determine the usage charge for that schedule equal to the difference between the LMPs at the two locations. (In the picture above, this charge is represented by the box "Buy through Congestion.") In the settlements, parties whose transactions created or increased congestion pay the marginal cost of congestion redispatch to relieve the congestion, and parties whose transactions decreased congestion (by creating counterflows) receive a credit/payment for the marginal benefit, reflecting the reduced need for redispatch (and attendant savings). In any case, LG&E/KU and other parties whose customers have been paying the revenue requirements (including fixed costs) of the transmission grid will also receive FTRs that reflect the grid value they have been paying for. In the settlements, holders of FTRs will receive credits equal to the difference in the LMPs between sink and source (ignoring losses), and these credits will offset the congestion charges for corresponding energy transactions. (The allocation of FTRs and settlement of FTRs are both shown in the picture above in the bottom right corner.)

Q. DOES THE USE OF LMP REQUIRE LG&E/KU AND OTHERS TO PAY FOR CONGESTION IN DELIVERING THEIR OWN (OR BILATERALLY CONTRACTED) GENERATION ENERGY TO THEIR OWN LOADS?

A. Yes, but that is only part of the story and ignores the offsetting settlement effect of FTRs. When both are accounted for, the net effect is that LG&E/KU will typically not owe a net payment for congestion for the transactions on which it has historically relied to serve its loads.

All transmission schedules will be subject to LMP-based congestion charges, but LG&E/KU and other LSEs will also be allocated FTRs that will entitle them to receive a settlement credit that can offset the congestion charges. For example, when LG&E/KU is using the transmission system to deliver its own generation energy to its own loads on transmission it owns within its service area, LG&E/KU would have been allocated the FTRs associated with the value of the grid for which its customers had paid. The settlement value of these FTRs in the ISO settlements would ensure that LG&E/KU could deliver its own generation to its own loads at the cost of the supplying generation, as though there had been no explicit charge for congestion.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES HOW ANY CONGESTION CHARGE ASSOCIATED WITH THAT DELIVERY WOULD BE OFFSET BY THE FTR CREDITS.

A. Suppose LG&E/KU has a 100 MW bilateral contract with a long-time supplier that will deliver energy to LG&E/KU at location A (location A could be the bus where a generator injected or some other agreed upon delivery point, such as a hub). LG&E/KU would then need to transmit the energy to its loads at location B. The bilateral contract calls for energy to be delivered from the supplier for $30/MWhr. Assume there is congestion on the transmission system such that the LMP at location A is $30/MWhr while the LMP at the load location B is $40/MWhr. The source Location A is somewhere within the Midwest ISO footprint, and may or may not be in LG&E/KU's service area, so the energy may travel over other lines and partly over lines that are owned by LG&E/KU. However, LG&E/KU has historically reserved firm transmission from this source location to its loads. Because LG&E/KU has paid for this firm transmission and LG&E/KU customers have been paying the revenue requirements (for network service) for the transmission owned by LG&E/KU, LG&E/KU would be allocated 100 MW of FTRs from A to B corresponding to the A-to-B firm transmission it (and its customers) have been paying for.

LG&E/KU would schedule this bilateral transaction in the ISO's day-ahead market. In the day-ahead market settlement, LG&E/KU is credited for the 100 MW of energy for each hour at the LMP at A and debited for this amount for each hour at the LMP at B. The resulting settlement for congestion (ignoring losses)[16] is as follows:

Congestion charge = Schedule Quantity X (LMP_B minus LMP_A), or
Congestion charge = (100 MW X \$40/MW) – (100 MW X \$30/MW) = \$1000

In addition, LG&E/KU would receive a rebate or credit for the 100 A-to-B FTRs it holds:

FTR rebate = Quantity of FTRs X (LMP_B minus LMP_A), or
FTR rebate = (100 MW X \$40/MW) – (100 MW X \$30/MW) = \$1000
Net congestion charge less FTR rebate = \$0
Net cost to LG&E/KU = the contract price of \$30/MWh

The example shows that as long as LG&E/KU implements its bilateral transaction as scheduled, the FTR rebate "hedges" (offsets) LG&E/KU's congestion charge, allowing LG&E/KU to deliver the energy to its loads at the contract price it agreed to with its supplier.[17] Of course, if either the supplier or LG&E/KU does not follow this schedule, any deviations in real time would be settled as either purchases or sales of spot energy at the location where the deviation occurred. So, for example, if LG&E/KU's supplier injected only 95 MW at location A when it was supposed to deliver 100 MW, the

16 The example could be expanded to show that the LSE that paid marginal losses would receive a rebate of the difference between marginal losses and average losses.

17 There is nothing in the EMT that compels LG&E to own exactly the same amount of FTRs as its expected transactions or to own FTRs whose locations match the sources and sinks of its expected schedules. It may own more or fewer A-to-B FTRs than the MWs it plans to schedule. It may also own a different set of FTRs, such as from C-to-D or from X-to-Y, or any combination it chooses. In the day-ahead settlements, LG&E would receive the settlement value of all of the FTRs it held, and it would pay the congestion charges for the schedules it submits. The FTRs do not have to match the schedule locations, either to get access to the grid or to provide an effective hedge.

supplier would, in effect purchase 5 MW from the ISO spot market at location A at the LMP at A ($30/MWhr). Note that if this occurs, the ISO's dispatch will dispatch an additional 5 MW so that LG&E/KU's 100 MW load is fully served. Even if LG&E/KU's supplier had a total forced outage and no backup generation, the ISO dispatch would automatically dispatch 100 MW more to keep the system in balance. LG&E/KU would not have to scramble for an alternative supplier, because the scheduled amounts would be covered by the dispatch, while the supplier (not LG&E/KU) would be properly charged for its spot purchases to cover its schedule obligation and be settled at the corresponding LMP.

Q. DOES THE EMT FORCE LG&E/KU TO ACCEPT UNREASONABLE COUNTERPARTY RISKS IN THE SPOT MARKETS?

A. No. Again, LG&E/KU will retain control over the extent it chooses to use the ISO spot markets to meet its loads and/or make off-system sales. It may choose to rely almost exclusively on balanced bilateral contracts and self schedules and thus avoid reliance on spot market purchases and sales except for imbalances and deviations from schedules. In addition, the ISO itself will establish reasonable credit risk mechanisms to ensure that parties who use the ISO spot markets are not exposed to unreasonable counterparty risks. The Midwest ISO will be able to track third party participation in its markets, establish appropriate credit requirements and thereby limit the risk exposure of creditworthy parties.

Q. DOES THE EMT ALLOW A UTILITY TO HOLD SOME OF ITS OWN GENERATION BACK FROM THE DAY-AHEAD MARKET SO THAT THE GENERATION COULD BE USED IN THE EVENT IT IS NEEDED IN REAL

TIME TO BACK UP OTHER GENERATION OR TO MEET UNEXPECTED HIGHER LOADS THAT ARISE IN REAL TIME?

A. Yes. Generators can self-commit their units in advance and hold them at minimum operating levels for use if and when needed.

Q. DOES THE EMT ALSO ALLOW A UTILITY TO CONTROL HOW AND WHEN ITS GENERATION IS "COMMITTED?"

A. Yes. By "commit" I mean the decision to start up a generation unit and operate it at least at its minimum level of generation. Some units can be started quickly and reach their range of operating output in a relatively short period. These quick-start plants need not be committed too far in advance, as they can always be brought on line quickly when needed for economic or reliability reasons. Other units, however, may take several hours or more to start up and reach the minimum level of generation, so they may need to be "committed" well in advance to ensure that they are available to serve loads if and when needed. If a utility has such slow-start units that may not be in economic merit under forecast conditions, but could be needed if actual demands are higher than forecast (or there are unexpected outages) it is not uncommon for these plants to be started up in advance on a contingency basis, and held at the minimum levels of generation just in case they are needed. When this happens, the utility incurs start-up costs and minimum generation (mostly fuel) costs in committing these plants.

Because real-time loads may differ from day-ahead forecasts, generators with load obligations face some risk that they will start up more or fewer units than actually turn out to be needed. To help reduce these risks, and ensure that enough units are available for dispatch to cover loads not accounted for in day-ahead scheduling, the Midwest ISO will offer a day-ahead unit commitment service (called "RAC") that will optimize the unit commitment for each area and hold the utilities/owners harmless for commitment costs that are not recovered by payments in the energy markets. The optimization ensures not only that there are "enough" units committed to meet expected loads but also that the units the ISO selects are located in the right locations, given expected congestion patterns.

Q. CAN LG&E/KU CHOOSE WHETHER TO USE THE ISO'S OPTIMIZED UNIT COMMITMENT SERVICE?

A. Yes. Under the EMT, generation owners can choose whether and how they take advantage of this service. A generation owner can either self-commit its own plant or allow the ISO to "optimize" the plant's commitment,[18] in much the same way that the ISO attempts to optimize the security-constrained economic dispatch of those plants voluntarily offered for dispatch. The choice is up to the generation owner. If the owner decides to self commit its unit, it bears the start-up and minimum generation costs, and these costs may or may not be justified, depending on whether and how much the plant is actually dispatched to serve loads. The risks and costs of these self commitment decisions are incurred by utilities today and are presumably reflected somewhere in each utility's cost of service revenue requirements. Under the EMT, however, if the owner offers the plant to the ISO to optimize the commitment, and the ISO does commit the plant, the ISO assumes the cost risks. That is, the ISO will compensate the owner for its start-up and minimum generation costs to the extent that the revenues the plant receives in the energy markets is not sufficient to cover the plant's total start-up and operating costs at the level at which the plant is scheduled and dispatched. This rule, which is common (and commonly accepted) in other functioning ISO markets, reduces the generation owner's risks and, through an optimized unit commitment with other plants, tends to lower the overall cost of committing units that may or may not be needed in real

[18] Here, "optimize" means that the ISO will select plants to commit based on their commitment costs, as reflected in bid information provided by the generators. The ISO will attempt to minimize the cost to loads of commitment costs associated with having enough capacity available to meet the ISO's forecast of the next day's loads, after accounting for all other capacity scheduled by the parties or the ISO in the day-ahead market.

time, depending on uncertain load levels and other contingencies. Thus, instead of limiting generator flexibility, as LG&E/KU claims, the EMT's offer of a commitment optimization service expands the generator's options, reduces risks and optimizes unit commitment. These measures can lower the costs that utilities face in serving their loads.

Q. WHY DO SOME PARTIES (INCLUDING LG&E/KU) INITIALLY BELIEVE THAT THEY MAY LOSE CONTROL OVER DISPATCH AND UNIT COMMITMENT UNDER THE EMT?

A. It is my understanding that similar concerns were raised when other ISOs (*e.g.*, PJM) started EMT-like operations with unit commitment services, but these concerns diminished after parties became familiar with how the process works. In my opinion, the concerns may also arise from the link between assuring resource adequacy (having enough plants available to meet forecast demand plus operating reserve requirements) and the decisions to commit units before real time so that they are actually available in real time if they need to be dispatched to serve loads (and/or held for operating reserves).

Every electricity system has some type of adequacy requirement, and in the Midwest ISO footprint, that requirement may differ between different reliability councils (ECAR is different from MAPP, for example) and differ between states. To accommodate these differences, the Midwest ISO's EMT defines only a default reserve requirement (12 percent reserves) for load-serving entities. The EMT leaves it to the Regional Reliability Councils and/or the individual states to set the requirements and to determine how best to meet those requirements through various procurement means. Except for this default requirement, the Midwest ISO does not tell individual states how high to set reserve requirements or what processes utilities or load-serving entities (LSEs) in each state may or may not use to acquire (or contract for) the necessary capacity.

Q. HOW DOES THE ISSUE OF RESOURCE ADEQUACY RELATE TO THE ISSUE OF CONTROL OVER GENERATION?

A. Under the EMT, the Midwest ISO will have responsibility for ensuring sufficient operating reserves to meet NERC operating standards. The 12 percent default reserve requirement is a means to satisfy the NERC operating reserve standard. However, the requirement would not be meaningful unless plants that are counted well in advance towards meeting the reserve requirement are actually available for possible dispatch in real time in the event they are needed. The EMT does not require a utility to designate any given resource as meeting part of its resource adequacy obligation. The output of any plant that is not designated can be sold to any party, in or outside the Midwest ISO, at the owner's discretion. However, if the owner/utility does designate a plant as meeting its EMT reserve obligation – calling it a "Designated Network Resource" (DNR) – then the owner must choose how it will demonstrate to the ISO the plant's actual availability for possible real-time operation.

Q. WHAT CHOICES DOES THE EMT PROVIDE TO GENERATORS TO DEMONSTRATE THEIR AVAILABILITY?

A. The intent of the EMT is to give generators/utilities different choices in how they can demonstrate that the plants they designate as meeting the reserve requirements are actually available to ensure reliable operations. A utility/generator owner can: (1) offer a unit's output in the day-ahead market for possible dispatch, (2) schedule a bilateral with that unit's output in the day-ahead market, (3) self-schedule a plant's output with the ISO in the day-ahead market; (4) self commit or make the plant available for optimized commitment by the ISO in the day-ahead reliability commitment process. The EMT also allows a generator, through bidding or other notification, to indicate to the ISO that the plant is not available (*e.g.*, for maintenance outages). Note that these are the same kinds of choices that the utility generation owner would have in deciding how best to utilize a plant's capacity if the utility were solely responsible for generation dispatch and scheduling. Under the EMT, the Midwest ISO has the reliability responsibility for real-time dispatch and managing operating reserves. The Midwest ISO must therefore have the same kinds of information indicating how each plant that is meeting the reserve requirement is actually available to meet reliability requirements in real time. The EMT has given the utilities maximum flexibility in how they satisfy these requirements without undermining the ISO's ability to perform its essential reliability functions.[19]

Q. WOULD LG&E/KU LOSE THE ABILITY TO SELL THE OUTPUT OF A PLANT IN A BILATERAL CONTRACT IF THAT PLANT WERE COMMITTED BY THE MIDWEST ISO?

A. No. If a unit is committed by the ISO in the day-ahead time frame, the owner can still sell the output in a bilateral to any load in the ISO footprint and schedule that bilateral in the real-time market, only for the amount not committed.

Q. DOES THE EMT IMPOSE HIGHER COMMITMENT COSTS ON LG&E/KU IF IT CHOOSES TO MEET ITS LOADS PRIMARILY THROUGH SELF COMMITMENT?

A. No. The utility has the choice of self commitment or optimized commitment by the ISO. The suggestion that LG&E/KU would have to pay its own commitment costs plus a disproportionate share of the uplift for Midwest ISO commitment costs (see Gallus, at 14-15) is incorrect. The intent of the EMT is that if a party covers its own loads through any of the options provided in the day-ahead time frame, including bilateral and self-scheduling and/or self-commitment of its own resources, and/or purchases from the day-day-ahead market, it is not subject to additional settlement obligations in the real-time market. To the extent that the ISO incurs commitment costs on behalf of the

[19] Given this flexibility, it is misleading for LG&E to suggest that the Midwest ISO always has "first call" on the control of utility plants. The EMT gives plant owners considerable control and flexibility in choosing how their plants are used to meet loads.

larger market, the uplift to recover those costs is allocated to those real-time loads that were not covered in the day-ahead markets.

III. <u>The EMT Does Not Force LG&E/KU To Use Its Low Cost Resources To Serve Other Utilities' Loads At The Expense Of Its Own Loads, Nor Does It Force LG&E/KU To Rely On Higher-Cost Resources To Serve Its Own Loads. Instead, The EMT Allows LG&E/KU To Use Its Own Low-Cost Resources To Serve Its Own Loads, While Offering Opportunities For LG&E/KU To Serve Its Loads At Even Lower Cost.</u>

Q. DOES THE EMT ALLOW A UTILITY TO USE ITS OWN LOW-COST RESOURCES TO SERVE ITS OWN LOADS?

A. Yes. The EMT expressly accommodates parties who wish to (1) schedule bilateral transactions between contracted generation and their own loads and (2) schedule their own generation to serve their own loads. If a utility is a low-cost supplier, because it owns low-cost generation or has low-cost contracts with other suppliers, the utility can continue to rely on those low-cost resources to serve its own loads. Nothing in the EMT forces any entity to give up the economic benefits it has in access to low-cost resources.

Q. DOES PARTICIPATION IN A CENTRALIZED REGIONAL DISPATCH FORCE A LOW-COST UTILITY TO GIVE UP ITS LOW-COST ADVANTAGE IN SERVING ITS LOADS?

A. No. A regional economic dispatch will tend to dispatch the most cost-effective generation across the region to serve all loads not otherwise met through inflexible bilateral and self schedules. This means that the regional economic dispatch will tend to lower the overall cost of serving loads across the region. Low-cost providers cannot lose their low-cost advantage as a result of this regional economic dispatch, but they can improve that advantage by using the regional economic dispatch in two ways: First, if the regional economic dispatch results in prices in the utility's load areas that are lower than the utility's costs of serving those same loads when relying only on its own plants, the utility can lower its costs of serving loads by relying on the regional economic dispatch. Second, if the utility chooses to sell its output into the economic dispatch, and the resulting area prices are higher than it's plant's running costs, the margins the utility earns can be used to offset the higher prices. The cost of serving its load would remain no worse than the same, and could be lower. The market revenues make a contribution to the utility's generation revenue requirements, thus lowering the remaining cost of service to their native loads. This is the same benefit that a utility can achieve through economic off-system sales, whose profits are also available to reduce the revenue requirements that must otherwise be paid by the utility's native loads. Furthermore, the regional economic dispatch will facilitate the ability of low-cost providers to engage in profitable off-system sales, thus further reducing the remaining revenue requirements that would otherwise be paid by the provider's own native load customers.

Q. DOES THE EMT IMPROVE OPPORTUNITIES FOR UTILITIES TO ACCESS LOW-COST RESOURCES THEY DO NOT OWN OR HAVE UNDER CONTRACT?

A. Yes. Under the EMT, a load-serving entity has the option to purchase energy from the spot market in lieu of using its own plants or contracted resources to serve loads. If the spot market prices in the day-ahead or real-time markets are less than the operating costs of the resources upon which the LSE would otherwise rely, the LSE can lower its costs of serving loads by purchasing from the spot market. In addition, the EMT enhances the ability of all parties to arrange and implement bilateral transactions from resources anywhere in the Midwest ISO footprint and to make those transactions financially firm even in the face of congestion, using Financial Transmission Rights (FTRs).

Q. IS IT LIKELY THAT A "LOW-COST UTILITY" SUCH AS LG&E WILL FIND THESE MARKET OPTIONS ECONOMICALLY ATTRACTIVE?

A. Yes. While LG&E/KU is generally a low-cost utility, it does not always have the lowest-cost resources that could be used to meet its entire loads. There will always be periods in which LG&E/KU's lowest-cost resources are unavailable because of planned or forced outages, and during these periods, LG&E/KU would benefit from the likelihood that spot energy purchases would be less expensive than forcing LG&E/KU to rely exclusively on its remaining plants. In addition, it is my understanding that while LG&E/KU has very low cost base-load units and reasonably priced peaking units, its medium load units are not always the lowest cost resources available for meeting demands above base load levels. This means that even without outages at its lowest-cost plants, LG&E/KU could still find occasions when relying on purchases from the day-ahead and real-time markets would be cheaper than relying exclusively on its own or contracted resources.

Q. WHAT HAS BEEN THE EXPERIENCE OF UTILITIES IN OTHER RTO REGIONS WHEN REGIONALLY OPTIMIZED ECONOMIC DISPATCH AND SPOT MARKETS ARE INTRODUCED?

A. It has not been uncommon that the initial reaction from local utilities and other LSEs is that they expect to rely almost exclusively on their own resources or bilateral contracts to serve their own loads, just as LG&E/KU claims it would do. However, as they became familiar with the economic benefits of selectively using the open spot markets offered by the RTO, these parties began to use the markets more efficiently. Today, they selectively rely on the spot markets when it is economic to do so and rely on their own resources when that is the lower-cost option. Moreover, to ensure that they capture the comparative advantages, utilities that own their own generation tend to offer more of their flexible (dispatchable) generation to the RTO for optimized regional dispatch, because they know that by participating in the dispatch, they can serve their loads at the lowest possible cost. They realized that they can do no worse than if they relied exclusively on their own plants,[20] but they will often do better because of the savings possible in a regionally optimized economic dispatch.

Q. WOULD LG&E/KU ALSO BENEFIT FROM EXPANDED OPPORTUNITIES TO MAKE BENEFICIAL OFF-SYSTEM SALES?

A. Yes. The day-ahead and real-time energy markets created by the EMT will facilitate LG&E/KU's efforts to make off-system sales when it is economic to do so. If LG&E/KU chooses instead to arrange bilateral sales to other entities, the EMT will make those transactions easier to arrange and implement and more profitable, because of the reduction in transmission rates resulting from the elimination of "through and out" rates and "rate pancaking." The EMT assures all parties non-discriminatory access to the transmission grid throughout the Midwest ISO footprint and non-discriminatory access to the regional dispatch that supports transmission usage.

Q. IS LG&E/KU CORRECT IN SUGGESTING THAT MEMBERSHIP IN MIDWEST ISO WOULD HURT THE PROFITS IT WOULD RECEIVE FROM OFF-SYSTEM SALES?

A. No. LG&E/KU's argument boils down to an implicit acknowledgement that the ISO markets may tend to lower wholesale prices, thus reducing the profits LG&E/KU might receive from making off-system sales into the Midwest region. If that is true, the cost of serving LG&E/KU loads by relying on these markets could also be reduced. Moreover, if it is true, as we anticipate, that the ISO markets will be more efficient than current bilateral-only markets, then LG&E/KU as a *non-member* would also receive lower profits

---

[20] This "win-win" aspect of regional economic dispatch applies even if a smaller region already benefits from a "joint dispatch," as do LG&E and KU. Even if LG&E/LU realized every benefit of optimized "joint" dispatch for their two systems, they would still benefit from participating in a larger "joint" dispatch over a broader region. They would never do worse.

on average from selling into that more efficient market. However, as a member, LG&E/KU's postulated loss of profits would also be offset by better access (fewer barriers to) the larger regional market, thus allowing LG&E/KU to make more sales, at lower transaction costs, than it does today. In part VII of my testimony, I quantify the benefit from increased sales under various assumptions.

Q. CAN YOU EXPLAIN WHY LG&E/KU'S STUDIES SUGGEST THAT THERE IS LIMITED BENEFIT FROM THE POTENTIAL FOR REGIONALLY OPTIMIZED DISPATCH AND/OR INCREASED OFF-SYSTEM SALES?

A. There are a number of reasons, but a particularly important one has to do with the models LG&E/KU used. It is my understanding that the models LG&E/KU relied on are not capable of modeling how the network functions (they assume, *e.g.*, that available capacity at the interties is static) and thus do not accurately represent congestion or how the capacity of the network can change as a result of changes in net injection and net withdrawals at different locations. Static production cost models cannot show the higher costs of TLR curtailments or capture the benefits of using a regionally optimized, security-constrained dispatch, which can determine the least-cost way to dispatch generation across the region to reliably serve loads, balance the system and keep flows within operating security limits. The models we use at the Midwest ISO do capture these network interactions and thus provide a more realistic picture of the advantages of regional economic dispatch.

Q. DOES THE MIDWEST ISO'S REGIONAL ECONOMIC DISPATCH UNDERMINE LG&E/KU'S ABILITY TO MEET ITS OBLIGATION TO SERVE?

A. No. The suggestion that the EMT and its rules for participating in the ISO's scheduling process and/or regional economic dispatch will undermine a utility's ability to meet its obligation to serve is not correct. Each utility will continue to have the obligation to acquire sufficient resources to ensure that its loads can be reliably served. The Midwest

ISO's regional, security-constrained economic dispatch serves a related function, which is to coordinate the dispatch needed to ensure that the system remains in balance and keeps flows within operating security limits in real time. This function will support the utility's obligation to serve by keeping the lights on, given the resources acquired and made available for dispatch by the regulated utilities and other entities. The ISO's regional dispatch will also improve reliability throughout the region, better ensuring that all loads are reliably served. The ISO's regional economic dispatch, regional scheduling mechanisms and regional grid monitoring capabilities will enhance every utilities' options and abilities to reliably serve their native loads.

Q. WILL LG&E/KU LOSE CONTROL OVER CURTAILABLE RETAIL LOADS UNDER THE EMT?

A. No. Whether retail customers can participate directly in the ISO's wholesale markets is a matter for state regulators to decide. Moreover, under the EMT, the Midwest ISO may not curtail LG&E/KU retail load (absent an emergency in which it would work through LG&E/KU) unless the Kentucky PSC has approved that retail load's direct participation in the ISO markets.

Q. WILL LG&E/KU OR ITS CUSTOMERS BE HARMED IF THE EMT ALLOWS THE MIDWEST ISO TO UTILIZE A LOCAL UTILITY'S RESOURCES TO HELP SOLVE REGIONAL GRID PROBLEMS?

A. No. The simple answer is that under the EMT, whenever an LG&E/KU resource is called upon for dispatch, operating reserves or emergency responses, it will be fully compensated for at least its costs, and it will be compensated for more than its costs if the market value – LMP – is higher. LG&E/KU customers will therefore not be financially harmed, and the ISO's security-constrained dispatch will ensure that *all* loads are reliably served. In addition, there may well be occasions in which LG&E/KU and its customers will benefit from the ability of Midwest ISO to call on other regional resources to solve reliability problems on the LG&E/KU system. This will benefit LG&E/KU customers, by providing better reliability and regional coordination, and do so at a cost less than what it would cost LG&E/KU to provide the same level of reliability by relying exclusively on its own resources.

Q. IS THE CONCEPT OF REDUCING COSTS THROUGH REGIONAL SHARING AND DISPATCH COORDINATION NEW TO THE MIDWEST ISO OR KENTUCKY?

A. No. Utilities have long recognized that they can enhance the reliability of their individual systems and do so at lower costs by entering into various coordination arrangements with neighboring system operators, such as sharing of operating reserves, coordinated dispatch and mutual support obligations during emergency conditions. These sharing arrangements, sometimes implemented through "power pools," have historically been supported by utilities as cost-effective ways to deal effectively with reliability problems on an increasingly interconnected transmission network. Such coordination and sharing arrangements are considered "good utility practice," because the reliability and cost benefits of regional coordination are so obvious. Indeed, it is likely that LG&E/KU itself made these same arguments in explaining to the Kentucky PSC the advantages to Kentucky consumers of combining the operations of LG&E/KU and Kentucky Utilities when the two companies merged.[21] The EMT is, in effect, a regional coordination and sharing arrangement that will enhance both regional and local reliability in all areas by taking advantage of the benefits of regional security-constrained economic dispatch, regional reserve sharing and emergency response, and region-wide monitoring of grid conditions.

---

[21] *See, e.g.*, the quote from the LG&E/KU integration agreement, referred to in the Supplement Testimony of Mike Beer (at 16), which states that the Agreement would "provide the contractual basis for the coordinated planning, construction, operation and maintenance of the System to achieve optimal economies" which would be accomplished through "joint dispatch." The Midwest ISO's regional "joint dispatch" expands on this same concept to capture even greater "optimal economies."

Q. IS LG&E/KU CORRECT IN SUGGESTING THAT LOW-COST UTILITIES ARE LESS LIKELY TO BENEFIT FROM RTO MEMBERSHIP?

A. No. The enhanced *reliability* benefits of an RTO's regional security-constrained dispatch do not depend on whether the participating systems are high-cost or low-cost. Moreover, with respect to *economic* benefits, my testimony explains why even a generally low-cost utility can benefit from the ability of a regional economic dispatch to cover a local utility's loads when its own low-cost resources are out for maintenance or are otherwise not available. The ability to benefit from regional dispatch in lieu of TLRs depends more on the degree of interconnection, the extent of congestion, the location of plants that can be redispatched to relieve congestion and other factors than it does on whether the local utility is "low-cost."

Q. ARE THERE DIVERSITY BENEFITS FROM PARTICIPATING IN A LARGER REGIONAL MARKET?

A. Yes. A larger regional market provides a greater diversity of resources, technologies and fuels, allowing individual utilities to benefit from the reduced risks this diversity provides. The ability to access this larger market and to engage in regional reserve sharing also means that individual companies do not have to meet as high a reserve margin, for the same level of reliability, as they would if acting on a stand-alone basis.

Q. DOES A COMPETITIVE MARKET ITSELF TEND TO ENCOURAGE MORE EFFICIENT OPERATIONS?

A. Yes. Experience in other markets has shown that when generators are faced with larger regional markets, they have strong incentives to ensure availability and reduce their forced outage rates. I referred to this benefit in the report attached to my direct testimony. *See* Direct Testimony of Ronald R. McNamara at Exhibit RRM-1, p. 15.

IV. The Use Of LMP And FTRs Will Neither Increase Congestion Nor Increase The Costs And Risks Of Managing Congestion. Instead, LMP And FTR Values Will Make Today's Congestion And The Marginal Cost Of Managing That Congestion Transparent. In Addition, LMP And FTR Values Will Reveal Cost-Effective Solutions To Congestion, Including Generation And Transmission Investments That Reduce Congestion.

Q. DOES THE USE OF LMP INCREASE CONGESTION?

A. No. Congestion already exists on the transmission system. To manage this congestion, system operators must either limit access to the grid before it becomes over scheduled or curtail transactions (using TLRs) after the fact; or they can redispatch generation to bring flows within operating security limits. *LMP does not increase this congestion.* Instead, LMP determines the marginal cost of the regional security-constrained economic dispatch that relieves congestion. LMP thus reveals – makes transparent – the marginal costs of managing congestion through redispatch. LMP provides transparent price signals about the degree of congestion already present and the marginal costs of redispatching to relieve that congestion.

Q. CAN THE USE OF LMP LEAD TO REDUCTIONS IN CONGESTION?

A. Yes. LMP reveals the marginal cost imposed by injections and withdrawals at each location. If grid users face the LMPs in settlements, they can determine whether the choices they make are more or less costly than other options. They can calculate whether the value of their transactions is worth the marginal costs their schedules impose on the system. Faced with these transparent prices, grid users will tend to adjust their usage (*e.g.*, select generation sources/suppliers whose injections do not create as much congestion). Over time, different operational and investment choices will tend to reduce congestion towards economic levels.

Q. DOES THE USE OF LMP INCREASE THE TOTAL COST OF MANAGING CONGESTION?

A. No. LMP reflects the marginal cost of redispatching generation to manage congestion. It does not raise the cost of redispatch in any way. If anything, the use of a security-constrained economic dispatch (in lieu of uneconomic TLR curtailments) reduces the cost of managing congestion by choosing the least-cost dispatch that will keep flows within operating security constraints. Relying on TLRs to manage congestion almost always increases congestion management costs, because (1) the lack of precision and certainty in TLRs leads to calling more TLR curtailments than required to manage the actual congestion and (2) the TLR mechanism takes no account of economics.

Q. IS THE MARGINAL COST OF REDISPATCH DIFFERENT FROM THE AVERAGE COST OF REDISPATCH?

A. Yes. Marginal costs provide efficient price signals about the effects of taking actions on the grid, so it is important to use marginal cost pricing. In an LMP system, the difference between average costs (or actual costs in any given redispatch) and the marginal costs of redispatch creates a settlement surplus in the RTO spot market. This settlement surplus is used to fund FTRs. That is, the settlement surplus from using LMP that is attributable to congestion redispatch is returned to grid users through the FTRs. (The settlement surplus attributable to charging for marginal losses is returned to grid users through another mechanism described above.)

Q. DOES RELIANCE ON FINANCIAL TRANSMISSION RIGHTS (FTRS) INCREASE THE RISKS OF MANAGING THE COSTS OF CONGESTION?

A. No. LMPs monetize the risks of congestion that are already present. FTRs provide a means to hedge these monetary risks so as to avoid the physical and economic risks of TLR curtailments. Without these mechanisms, the risks of congestion would be seen through increased exposure to uncertain TLR curtailments and other non-economic restrictions on grid usage. The economic costs of those risks would be largely hidden. Thus, FTRS, like LMPs, make what was hidden before more transparent. Moreover, because FTRs are financial instruments and not physical rights that lock up grid capacity,[22] using FTRs does not undermine the ability of the RTO to arrange an efficient dispatch nor the ability of parties to arrange efficient transactions. FTRs retain their economic value (FTR holders are paid their settlement value based on the LMP differences) whether or not the FTR holder schedules a transaction matching its FTR.

Q. WILL LG&E/KU FACE HIGHER EXPOSURE TO UNHEDGED CONGESTION COSTS IF IT DOES NOT GET THE EXACT FTRS IT ASKS FOR?

A. Not necessarily. FTRs have a settlement value whether or not the FTR owner schedules transactions matching its FTRs. A non-matching set of FTRs could therefore provide an effective hedge against congestion charges.

Q. DOES LG&E/KU FACE UNUSUAL RISKS STEMMING FROM THE FTR ALLOCATION PROCESS PROPOSED IN THE EMT?

A. It will be important for each utility to carefully select a portfolio of FTRs that it believes best hedges these risk. With respect to LG&E/KU, our analysis suggests that it is likely that LG&E/KU faces unusual opportunities to benefit from possible FTR allocations, as I explain below.

The EMT's FTR allocation process will occur in several phases. In initial phases, utilities/LSEs voluntarily choose some of the FTRs to which they are entitled (a percentage of their base-load demand), based on their expected values and/or their match with expected schedules for serving their loads. The Midwest ISO will honor these

---

[22] Physical rights systems lock up capacity that may not actually be used, preventing other schedules from being implemented and thus raising costs for parties whose schedules could have been accommodated on the grid but were rejected. Further, the holder of a physical right can only achieve its value by using exactly that right – actually scheduling a transaction to match the right – which may not always be the economic choice. This "use-it-or-lose-it" feature of physical rights is a serious drawback to economic trades and a principal reason for using financial transmission rights instead.

requests to the extent they are simultaneously feasible. In later phases, additional FTRs are assigned by the Midwest ISO to match how utilities will probably serve their loads. These assignments are associated with counterflow schedules that help reduce congestion and thus allow the ISO to restore FTRs that were not simultaneously feasible in the voluntary phase of the allocation. When all phases are complete, each utility should have a set of FTRs that provides approximately the level of financial hedging needed to cover its exposure to likely congestion charges, given the capacity of the grid.[23] The process is not exact, but on balance we believe it is equitable. The initial allocation is for a limited period, and we expect parties to learn from the experience and improve their hedges in future allocations over time.

Q. WHY DO YOU SUGGEST THAT LG&E/KU MAY BE IN A FAVORABLE POSITION WITH RESPECT TO FTRS AND CONGESTION COSTS?

A. We have examined possible FTR allocations for LG&E/KU (and others) and have determined that LG&E/KU is in *an unusually favorable position* with respect to how transmission limits affect LG&E/KU's ability to serve its own loads at low costs. This position suggests that if LG&E/KU pursues a reasonable approach, it should be able to acquire more than enough FTRs to fully hedge its exposure to congestion charges,[24] and thus receive a net benefit from FTRs over congestion charges. In part VII of my testimony, I attempt to quantify that economic benefit.

---

[23] The allocation should not exceed this capacity, so the process will limit the total set of allocated FTRs to one that is simultaneously feasible. To violate this limit would be equivalent to awarding more physical rights to the grid than can be physically accommodated at the same time. That is the condition that frequently leads to TLR curtailments.

[24] By "cover its exposure," I mean that the utility will be able to achieve at least the financial equivalent of the firm transmission it could have exercised under the current regime with no net exposure to congestion charges. It should be understood that if firm transmission has been oversold under today's regime, parties would not be able to exercise all of it at the same time. The FTR allocation process will help make these oversold conditions transparent.

Q. HOW DOES THIS FAVORABLE CONDITION ARISE?

A. It appears that as a result of regional flows, a large portion of LG&E/KU loads are located in regions where we expect to see fairly low LMPs, meaning that it will cost less to serve LG&E/KU loads, while major LG&E/KU resources are located in regions that will tend to see higher LMPs, meaning that they will be credited in the ISO markets with higher LMP values for the energy they produce. This puts LG&E/KU in a highly favorable position. If LG&E/KU chooses to use its own resources to serve its own loads, it could create counterflows that are valuable (because they reduce congestion) in the ISO market settlements. Or put another way, LG&E/KU loads could be served at low costs from the markets while LG&E/KU resources could be sold into these markets at higher prices, giving LG&E/KU a net economic advantage. It would be reasonable to expect LG&E/KU to lock in this advantage in choosing its FTRs. It would then be up to the Kentucky PSC to determine whether to allocate the full economic benefits to LG&E/KU customers or consider allocating part to LG&E/KU shareholders (*e.g.*, as an incentive to encourage LG&E/KU to seek out such economies that lower its cost of service). The LMP system will make such opportunities more transparent.

Q. WILL THIS BENEFIT BE PARTIALLY OFFSET BY OTHER FTR-RELATED "UPLIFT" COSTS IMPOSED ON LG&E/KU?

A. Yes. LG&E/KU is correct in stating that under the provisions approved (or ordered) by FERC, an extra allocation of FTRs is to be awarded to utilities in Narrow Constrained Areas (NCAs).[25] These are areas that have traditionally experienced high levels of congestion. For these NCAs, FERC directed the Midwest ISO to award more than the simultaneously feasible set of FTRs as a means to convince participating utilities that they would not be financially harmed by congestion charges because of the degree of congestion in those areas. The net effect is likely to produce a set of FTRs than cannot

---

[25] Beer supplemental testimony at 7.

always be funded from the collection of congestion charges in the ISO markets. Any deficit in the funding of the FTRs would be recovered through an uplift charged to all parties, including LG&E/KU. We estimate LG&E/KU's cost from this uplift to be approximately $1 million per year for the five-year transition period.

I agree that this "subsidy" to those regions does not follow normal cost causation principles and that ideally it should be eliminated. It was FERC's determination that requiring others to pay this subsidy over a limited transition period was in the public interest, presumably because it would help ensure that the RTO covered a large and physically contiguous region of the interconnection. After considering the experience and "growing pains" of other RTOs, we reluctantly accepted the principle that to achieve the full benefits of regional dispatch and grid coordination it may be necessary to accommodate such transitional arrangements that fall short of the ideal.

It is important to note that the total of uplift payments that LG&E/KU considers to be "subsidies"[26] falls far short of the net benefits we estimate for the LG&E/KU system as a result of its participation in the RTO regional economic dispatch, the RTO's regional markets, and the allocation of region-wide FTRs. In part VII of my testimony, I attempt to quantify this net benefit from LG&E/KU's RTO participation in the Midwest ISO.

Q. WILL THE USE OF LMP AND FTRS REVEAL COST-EFFECTIVE SOLUTIONS TO CONGESTION?

A. Yes. Higher LMPs at some locations than others will signal locations where it would be preferable to site new generation or invest in demand-side management. LMP locational differences reveal the cost of managing congestion between those locations, and the forward prices that parties pay for long-run FTRs reveal what the market is willing to pay

---

[26] The EMT's solutions for accommodating so-called "grandfather agreements" (Option B) may also require an extra allocation of FTRs, though its financial impact on LG&E and others should be less than the allocation for NCAs.

to avoid congestion, such as by expanding the grid. LMP and FTR values together indicate situations in which transmission upgrades would be cost effective.

Q. WILL THE USE OF LMP AND FTRS PROVIDE ECONOMIC INCENTIVES FOR GENERATION AND TRANSMISSION EXPANSION TO REDUCE CONGESTION?

A. Yes. LMP and FTR price signals will provide incentives to market participants to invest in generation at the right locations and transmission upgrades that reduce congestion to economic levels. They will also provide regulators with useful economic measures of the value of investments proposed by utilities for rate base treatment.

V. The EMT Will Not Cause The Kentucky PSC To Lose Regulatory Control Over Any Aspects Of *Retail* Rates Or *Retail* Service. The EMT Will Improve The Efficiency Of *Wholesale* Markets And Regional Transmission Access, Which Should Help Kentucky Preserve Its National Status As A Low-Cost State.

Q. ARE LG&E/KU'S CLAIMS THAT THE EMT WILL ERODE STATE AUTHORITY OVER RETAIL RATES AND TERMS AND CONDITIONS OF RETAIL SERVICE ACCURATE?

A. No, they are incorrect. The EMT establishes a regionally optimized economic dispatch and a set of day-ahead and real-time energy markets that function entirely at the *wholesale* level. The prices paid and received in these markets are prices for wholesale energy and transmission usage. The prices for wholesale transactions and transmission have always been subject to FERC jurisdiction under the Federal Power Act. The Midwest ISO does not have, nor can it seek, authority over any aspects of *retail* electricity service, which remains with the states. The EMT does not, indeed legally cannot, change the allocation of regulatory authority between FERC and the State of Kentucky. Under the Federal Power Act, FERC also has authority over the terms and conditions of transmission service. As a FERC-regulated entity, the Midwest ISO will offer non-discriminatory, open access transmission service to all parties and so will be subject to FERC oversight.

Q. DOES THE EMT UNDERMINE THE KENTUCKY PSC's AUTHORITY OVER GENERATION SITING APPROVALS?

A. No. Nothing in the EMT affects a state's authority over power plant site certification and associated environmental reviews. States also retain environmental review over new transmission lines. Further, the EMT does not allow the Midwest ISO to determine where new generation will be sited.

Q. WILL THE EMT PREVENT THE KENTUCKY PSC FROM ENGAGING IN INTEGRATED RESOURCE PLANNING WITH KENTUCKY UTILITIES?

A. No. States in RTO regions remain free to engage in integrated resource planning with their respective jurisdictional utilities. As the provider of regional transmission service, the Midwest ISO will also offer a regional transmission planning process in which all parties, including transmission owners and state regulatory commissions, can participate. Under the EMT, how utilities respond to the needs identified in the RTO planning exercise remains subject to state control.

Q. WILL THE KENTUCKY PSC LOSE AUTHORITY OVER RETAIL RATES UNDER THE EMT?

A. No. Nothing in the EMT asserts authority over the setting of retail rates. The EMT contains provisions for how transmission service is provided and how *wholesale* spot prices are defined, but the EMT does not force any party to rely primarily on the wholesale spot markets to acquire power. If, for example, utilities rarely use the spot markets and rely primarily on their own resources to serve their own loads, there could be little if any effect on retail rates. States are free to determine how much they wish their regulated utilities to rely on regional wholesale markets and how much on their own resources. States are also free to determine how wholesale power costs in general, whether from bilateral transactions or spot purchases, are reflected in retail rates.

Q. DOES THE EMT CONVERT RETAIL SALES TO WHOLESALE TRANSACTIONS AND THUS MAKE THEM SUBJECT TO FERC AUTHORITY?

A. No. Bundled retail service, as used in Kentucky, is not subject to FERC jurisdiction and remains within the jurisdiction of the State.

Q. WOULD A RESOURCE ADEQUACY MECHANISM AT MIDWEST ISO UNDERMINE THE KENTUCKY PSC's AUTHORITY OVER HOW KENTUCKY UTILITIES ACQUIRE RESOURCES?

A. No. At present, the Midwest ISO does not have a mechanism that requires LSEs or utilities to acquire resources in any particular manner. The design of these mechanisms is left to each state. The Midwest ISO has only a default 12 percent reserve requirement. This default requirement is reasonably necessary to ensure that there will be sufficient operating reserves in real time to meet forecast loads plus reserve requirements. It should be understood that if the Midwest ISO did not impose some standard on all LSEs in a region, then it would be possible for LSEs in some areas to "lean" on the resources developed by other entities. That is, in a free-flowing grid such as the Eastern Interconnection, it would be very difficult for Kentucky and its utilities to prevent other LSEs from leaning on the reserves developed and paid for by Kentucky utilities and their customers. The EMT requirement asks that each utility/LSE meet its share of the collective reserve requirements.

Q. COULD THE MIDWEST ISO DEVELOP FORMAL "CAPACITY MARKETS" IN THE FUTURE TO DEAL WITH RESOURCE ADEQUACY ISSUES?

A. Yes, that has occurred in other RTOs. The Midwest ISO is currently sponsoring working groups to consider potential ways to address resource adequacy over the long run. State regulatory commissions play a prominent role in these discussions, through the Organization of Midwest ISO States (OMS). Moreover, FERC has made it clear that it is prepared to give deference to Regional State Committees (like OMS) on how best to design regional resource adequacy mechanisms.

The Kentucky PSC is an active member of the Organization of Midwest ISO States, one of the first functioning RSCs in the nation. Through the OMS, Kentucky has both a forum for and a voice in the resolution of regional planning and expansion issues and the allocation of regional expansion costs. These benefits would not exist but for Kentucky's participation in the Midwest ISO/RTO and the OMS.

VI. <u>LG&E/KU And Kentucky Cannot Achieve The Benefits Of An RTO Through Any Of The "Alternatives" To Midwest ISO Membership Described By LG&E/KU.</u>

Q. IS IT POSSIBLE FOR LG&E/KU TO OBTAIN THE SAME OR GREATER BENEFITS UNDER ANY OF THE ALTERNATIVES IT DESCRIBES TO CONTINUING PARTICIPATION IN THE MIDWEST ISO RTO?

A. No. The only way that LG&E/KU could achieve benefits comparable to or better than those it could achieve from membership in the Midwest ISO RTO would be if the "alternatives" to that membership provided the same (or greater) regional functionality and the same (or better) benefits of non-discriminatory open access to transmission as will be provided under the EMT. Neither the TVA nor SPP option comes close to offering the same features.

Q. HOW WOULD YOU ASSESS THE SUGGESTED USE OF TVA OR SPP AS A RELIABILITY COORDINATOR FOR KENTUCKY?

A. TVA could provide the limited functions of a "reliability coordinator," which monitors regional transmission schedules and administers the system of TLRs to unschedule the grid when it becomes overscheduled. It is important to understand that this function falls far short of the improved regional coordination that should be available for the Kentucky transmission system. Today's reliability coordinators function within the framework of the old physical rights system and contract path scheduling. These mechanisms frequently result in over-scheduling of the transmission system that must be corrected to keep flows within safe operating limits. Without a regionally optimized dispatch to solve this problem at the lowest redispatch cost, local utilities can only turn to their Reliability Coordinator to "unschedule" the grid through TLR curtailments. TLRs have proven to be inadequate for the many reasons outlined in my previous testimony, including the facts that they ignore economics, leave the grid under used, and disrupt far too many transactions, all of which are ultimately serving some utility's native loads. To effectively solve the problem of scheduling the interconnected grid up to its transfer capacity, while assuring that flows remain within operating security limits, RTOs should offer a regionally optimized, security-constrained economic dispatch. The security-constrained dispatch solves congestion and does so on a lowest cost basis for the region, thus avoiding the uneconomic and often uncertain reliance on TLRs. Thus, it is misleading for LG&E/KU's witness[27] to compare having some new third party provide this traditional but limited service with the regional dispatch and reliability capabilities that Midwest ISO is offering. At this time, SPP and its members have not agreed that SPP should have this essential function. Importantly, LG&E/KU is not suggesting that it submit its generation and transmission system to an optimized regional dispatch coordinated by TVA, SPP or any other regional entity.

Q. COULD LG&E/KU ACHIEVE COMPARABLE BENEFITS AND FUNCTIONALITY BY JOINING SPP?

A. Not in the foreseeable future. Although FERC has provisionally approved SPP as an emerging RTO, SPP has a long way to go to achieve the functionality achieved by the

[27] *See* Supplemental Testimony of Mark S. Johnson, at 2.

Midwest ISO and other RTOs. The regional dispatch approach used in the Midwest ISO and in Eastern RTOs has been shown to be a workable approach for solving these problems for meeting the requirements of FERC Order No. 2000.

Q. IS THERE ANY REASON TO BELIEVE THAT A COMPARABLY FUNCTIONAL SPP WOULD BE ANY LESS COSTLY THAN MEMBERSHIP IN MIDWEST ISO?

A. No. If SPP were to replicate the regional dispatch and market functions that Midwest ISO has already developed, if would have to do so from scratch. There is no reason to believe that SPP could do so at lower cost for its members. If anything, SPP's small membership and lower total load would probably mean that the costs per MWh of SPP administrative expenses and capital costs would be higher than they are for Midwest ISO.

Q. ARE THERE OTHER PRACTICAL ISSUES ASSOCIATED WITH LG&E/KU JOINING SPP?

A. LG&E/KU's transmission system is not contiguous with SPP's systems; it is "two wheels away." There is no apparent logic for a Kentucky utility to be considering joining an RTO so far distant from its own transmission system and no apparent reason to believe that this arrangement could benefit Kentucky in any way.

Q. ARE MIDWEST ISO COSTS HIGHER THAN PJM?

A. No. Currently, PJM's rates total about \$0.397/MWh (39.7 cents/MWh). while the Midwest ISO's rates total about \$0.386/MWh (38.6 cents/MWh). They are roughly the same.

Q. WOULD LG&E/KU LOWER ITS COSTS BY SWITCHING TO PJM?

A. No. LG&E/KU is already committed to remain with the Midwest ISO at least through 2005, which means it will incur whatever costs are associated with working with Midwest ISO and its settlement systems. By leaving Midwest ISO to join PJM, LG&E/KU would be subject to a significant withdrawal fee but would not be receiving any offsetting benefit.

VII. Benefit - Cost Analyses

A. Overview of Benefit – Cost Analysis Findings

Q. HAS THE MIDWEST ISO COMPLETED FURTHER ANALYSIS OF THE BENEFITS AND COSTS OF MIDWEST ISO MEMBERSHIP TAKING INTO CONSIDERATION THE ORDERS OF THE FERC REGARDING IMPLEMENTATION OF THE MIDWEST ISO EMT?

A. Yes. When I presented my direct testimony in this proceeding, I described an initial modeling analysis which indicated that LG&E/KU and their customers could expect to achieve savings from regionally coordinated economic dispatch and participation in the Midwest ISO regional energy markets. Having reviewed the Companies' supplemental testimony in this proceeding, we have updated our analysis to reflect FERC Orders regarding implementation of our EMT and to address the remaining uncertainties inherent in such a forecast of alternative futures. Our expanded analysis clearly demonstrates that under any plausible set of assumptions LG&E/KU and their customers would suffer significant economic losses by withdrawing from the Midwest ISO.

Q. PLEASE SUMMARIZE YOUR FINDINGS WITH RESPECT TO THE BENEFITS AND COSTS OF LG&E/KU CONTINUING TO PARTICIPATE IN THE MIDWEST ISO AFTER IMPLEMENTATION OF THE EMT IN COMPARISON TO OTHER OPTIONS THAT MAY BE AVAILABLE TO THE COMPANIES.

A. LG&E/KU occupy a unique position in the middle of the transmission grid for eastern North America. The LG&E/KU system includes transmission elements that regularly constrain interregional power flows. As a result, extending regional congestion management to the LG&E/KU system creates significant economic gains. And, if they participate in the Midwest ISO's regional economic dispatch and energy markets, LG&E/KU and their customers will benefit from the resulting efficiency improvements.

When compared to continued participation in the Midwest ISO, if the Companies withdraw to pursue the Transmission Owner – Reliability Coordinator (TORC) option, LG&E/KU and their customers can expect a net annual increase in their costs of service, after deducting the costs for the EMT implementation, of $43.9 million per year. Taking into account both these recurring costs and the additional exit fee of $40.2 million which LG&E/KU would have to pay to withdraw effective January 1, 2006 – the earliest date on which they could withdraw under the Midwest ISO Transmission Owners' Agreement, leaving the Midwest ISO could cost LG&E/KU customers $303.6 million in additional costs and foregone benefits over the period 2005 through 2010. The present value of these near term economic impact is $264.1 million. Please refer to the attached Table 1 for a summary of these near-term benefits and costs.

This Commission can have a high degree of confidence that the net benefits to LG&E/KU and its customers of participating in the Midwest ISO's regionally coordinated economic dispatch and energy markets under the new EMT will be significant and positive. We examined a broad range of sensitivity cases involving 23 different combinations of key input variables. In each of these cases, the recurring annual net benefits of Midwest ISO membership to LG&E/KU and their customers remained significant and positive. The results of these cases showed that when compared to continued Midwest ISO membership the TORC option could cost LG&E/KU between $5.3 million more in the best case for TORC to $101.9 million more per year. Please refer to Table 6.[28] These projections of recurring annual savings do not take into consideration the exit fee that the Companies would have to pay upon withdrawal from

[28] The detailed results for these cases can be found in Tables 3 and 7-11 (attached).

the Midwest ISO. The results of our base case projection of $43.9 million represent a conservative view of the most likely annual cost of pursuing the TORC option.

Moreover, these results reflect only the near-term economic benefits of continued membership in the RTO. Having a transparent energy market over time will improve incentives, facilitate enhanced regulatory oversight, promote reserve sharing, and may permit the Companies to avoid capital investments that otherwise would be needed. For example, our modeling suggests operating additional generating capacity at the Trimble County site may in some circumstances further constrain transmission, limit regional power flows, and be more costly than locating generation in other portions of the LG&E/KU system. The EMT markets would help make such economic signals transparent and highlight opportunities to reduce costs for LG&E/KU and their customers. The Midwest ISO EMT is an investment in producing intermediate and long-term economic efficiencies that will benefit Kentucky consumers, if LG&E/KU remain within the Midwest ISO.

Placing the economic analysis in context, I disagree with the "assumption" in the Companies' supplemental testimony that each of the available options would provide LG&E/KU customers equivalent reliability. For Kentucky and the portions of the grid with which LG&E/KU are most closely interconnected, the Midwest ISO offers regional real-time visibility of power flows and contingencies, the most detailed available network model of transmission operations, and advanced reliability coordination tools that are not available from other reliability coordinators. The Midwest ISO has developed, and over the last 15 months significantly enhanced, its reliability coordination tools and capabilities specifically to serve LG&E/KU and other RTO members. If LG&E/KU were to withdraw, there would be significant negative reliability impacts for LG&E/KU customers.

From the findings that the TORC option is more costly than continued membership in the Midwest ISO, the Commission can also conclude that withdrawing from the Midwest ISO to join SPP would be a more expensive option. Assuming for the sake of argument that the FERC would permit them to leave Midwest ISO to join SPP, LG&E/KU would have to pay additional costs for SPP membership, but would receive fewer benefits from centralized dispatch and little or no benefit from improved access to markets. The Companies are not physically connected to any SPP transmission owners. Even if LG&E/KU could purchase a transmission path that might create such a connection and reach coordination agreements to manage the related seams, the operation of the Companies system would be difficult to integrate with those of a region that is in centered in Kansas, Oklahoma, and northern Texas and includes smaller portions of New Mexico, Arkansas, and Louisiana.

Finally, I concur with Companies' witness Morey that "switching to the PJM RTO would not be improving the welfare of retail customers in Kentucky." While the functions of the two RTOs are comparable, the Companies would have to pay both a Midwest ISO exit fee and higher PJM administration fees.

Q. WHAT ARE THE PRIMARY FACTORS THAT MAKE THE TORC OPTION MORE EXPENSIVE THAN CONTINUED MEMBERSHIP IN THE MIDWEST ISO?

A. There are four primary factors that on a recurring annual basis make TORC operations more expensive than continued membership in the Midwest ISO.

1. The Midwest ISO regional economic dispatch reduces the costs associated with managing congestion and facilitates the purchase of economic power to reduce generation and purchased power costs to serve LG&E/KU control area load. Under the TORC option, generation and purchased power costs would be $4 million per

year higher than what could be achieved with Midwest ISO coordinated dispatch. Please refer to the attached Tables 2 and 3.

2. One result of implementing centralized economic dispatch will be the creation of one of the world's largest day-ahead and real-time power markets. The Midwest ISO spot market will be coordinated in real time with changing power flows and optimized with respect to transmission constraints. Participation in the Midwest ISO energy markets will identify opportunities for power sales that would never be realized within a bilateral market. Without participation in regionally coordinated economic dispatch, bilateral trades cannot be fully and effectively integrated with the operation of the transmission system. Moreover, withdrawal from the Midwest ISO will tend to reduce the price that LG&E/KU can expect to receive for its remaining off-system sales. In the absence of participation in regionally coordinated transmission operations, LG&E/KU would lose the opportunity to sell at a premium when its generation is needed to relieve transmission constraints. And the presence of a large, efficient regional market adjacent to LG&E/KU will tend to depress prices for LG&E/KU generation in comparison to both current prices and the prices available to LG&E/KU as a member of the Midwest ISO. As a result, under the TORC option, LG&E/KU can expect to lose at least $27.3 million per year in net margins on off-system sales. This figure conservatively assumes that LG&E/KU could increase its off-system sales under the TORC option to levels that are nearly double the average levels projected for the TORC option in the Company's Supplemental Testimony.[29] A comparison of sales volumes and prices for the different cases is contained in Table 4; the increase in costs from the TORC

[29] The projected volume of off-system sales in our base case analysis is 9,127 GWH per year for the TORC option and 14,178 GWH per year for LG&E/KU in the Midwest ISO. Due to our use of conservative hurdle rates, the projected off-system sales in our analysis of the TORC option are more than 197 percent of the annual average off-system sales projected for the TORC option in Mr. Gallus' Supplemental Testimony at p. 9.

option result in part from reduced utilization of LG&E/KU generation as indicated in Table 5.

3. By continuing its membership in the Midwest ISO, LG&E/KU will continue to receive a distribution of transmission revenues from Schedules 1, 7, 8, and 14 of the Midwest ISO tariff. Based on actual settlements with LG&E/KU over the last 12 months, these revenues are expected to be approximately $25.7 million per year. While a number of factors may influence these revenue distributions in the future, these actual values represent the best evidence of likely future revenue distributions.[30] By contrast under the TORC option, LG&E/KU transmission would be surrounded by large interconnected systems. And LG&E/KU transmission revenues would be almost entirely limited to revenues from transmission service supporting LG&E/KU off-system sales. Third parties would have no incentive to reserve a contract path for transmission service that includes a stand alone LG&E/KU system. Given our very conservative assumption about an increase from historical levels in LG&E/KU off-system sales under the TORC option, our base case analysis reflects the loss of a net $6.1 million per year in transmission revenues under the TORC option. See Table 2.

4. Our analysis indicates that LG&E/KU congestion costs to serve control area loads are likely to be low compared to the value of the FTRs that the Companies will have an opportunity to nominate. In our base case, LG&E/KU congestion costs total $35.2 million per year. The Companies' total congestion costs are moderated in some hours by conditions where major LG&E/KU's loads are upstream and large

[30] Events that could reduce this amount would be the elimination of the through and out rate between the Midwest ISO and PJM as well as a reduction in the quantity of point-to-point transmission service into or within the Midwest ISO footprint. On the other hand, the development of a regional market could increase Midwest ISO transmission revenues through increasing exports and reconsideration of the current practice of discounting rates for point-to-point service. Moreover, reductions in point-to-point service reservations may be offset by additional FTRs becoming available for auction. On balance, using the actual values for the last 12 months as a guide for the future is warranted.

LG&E/KU generating stations are downstream from transmission constraints created by broader regional power flows through their system. Under these conditions LMP prices at their upstream load centers fall while prices at downstream generators located near to the constraint increase. The downstream LG&E/KU generators in these circumstances will enjoy higher prices in the Midwest ISO LMP market because increased power production at these facilities creates counter flows that alleviate the constraint. Such price signals would not be present in a bilateral market. While final FTR allocations may not be known until early 2005, the Midwest ISO with input from market participants developed an illustrative summer season, peak period FTR allocation in April 2004. Making a conservative assumption regarding the FTR opportunities that will be available to LG&E/KU, our base case analysis modified this illustrative allocation by assuming that LG&E/KU would be required to take in all seasons and peak and off-peak periods all of their base load (Tier 1 and Tier 2) allocation including money losing FTRs. In the actual allocation process, LG&E/KU will be free to not nominate FTRs that might lose money. While the counter flow restoration step at the end of the Tier 2 allocation might require them to take some money losing base load FTRs where necessary to enable other companies to receive FTRs for their base load generation, it is highly unlikely that LG&E/KU would have to take all such FTRs.[31] With this conservative assumption, we projected that LG&E/KU would have an opportunity to nominate FTRs valued at $58 million per year.[32] While we considered cases with a range of positive and negative FTR over congestion cost values, our base case reflects LG&E/KU's unique position in the grid and the

[31] LG&E/KU would not be required to take counter flow restoration FTRs for non-Midwest ISO loop flows or to support additional FTRs for their own load.

[32] This includes a $2 million per year projected share of FTR auction revenues. *See also* Supplemental Investigation Report at 49 as attached to the Supplemental Testimony of Mathew Morey.

resulting opportunities available to the Companies to benefit from a system which actually rewards their capacity to redispatch generation in a way that permits more efficient regional power flows. See Table 3.

Our analysis also considers the administrative charges associated with RTO start-up and operations, transitional transmission uplift charges, and what the Companies claim will be an increase in their Administrative and General expenses associated with RTO membership.

Q. HOW CONFIDENT CAN THE COMMISSION BE THAT THERE WOULD BE SIGNIFICANT RECURRING NET COSTS TO LG&E/KU AND THEIR CUSTOMERS ASSOCIATED WITH WITHDRAWAL FROM THE MIDWEST ISO AND OPERATING ON A TORC BASIS?

A. The Commission can have a very high degree of confidence that it would be significantly more expensive for the Companies to pursue the TORC option than to remain in the Midwest ISO after the implementation of the EMT.

The issues presented in this case involve the counterfactual evaluation to two alternative approaches to future operations. Whether LG&E/KU remains within the Midwest ISO or leaves to pursue a different option, the future will not look like the past. The historical trend within our industry is that improvements in information and communications technology have permitted parties with information to engage in additional economic transactions between control areas. And these transactions have increased power flows across the region. That trend will continue. And the development of the Midwest ISO regional energy markets will alter the economic landscape for LG&E/KU in a manner that provides advantages to Midwest ISO members. Our analysis indicates that if LG&E/KU leaves the Midwest ISO and the EMT creates a large regional market adjacent to the Companies' service territory, the creation of an adjacent market alone is likely to lead to a decline in LG&E/KU off-system sales revenues of more than

$27 million per year and could increase the net cost to serve LG&E/KU load by $15.1 million relative to what would have occurred with a continuation of the Midwest ISO Day 1-type operations. Please refer to the attached Table 3. Thus, it is not sufficient to assume that a future outside of the Midwest ISO will approximate the past.

In this case, the recurring costs of leaving the Midwest ISO to pursue the TORC or SPP options are large. And we have analyzed a large number of sensitivity cases indicating that under a broad range of conditions the recurring annual costs of the TORC (or SPP) option(s) remain positive and significant.

Q. WOULD YOU PLEASE DESCRIBE THE SENSITIVITY ANALYSIS THAT YOU CONDUCTED?

A. We started with a base case that was built on a conservative set of inputs that were designed so as to avoid overstating the costs of LG&E/KU withdrawal from the Midwest ISO. These are described in a later section of my testimony. We then modified those assumptions to determine how sensitive the results would be to alternative circumstances. And we began this process by modeling five alternative sets of input assumptions:

1. <u>Failure to meet objectives for improving transmission utilization under real-time dispatch</u>: With the implementation of the EMT, the Midwest ISO will start using real-time security-constrained economic dispatch to manage power flows across the grid. With real-time dispatch, the Midwest ISO will be sending new dispatch signals to generators across its footprint at least once every five minutes. Real-time dispatch provides the Midwest ISO a much more precise and immediate way to manage flows over constrained interfaces. As this system is implemented, the Midwest ISO intends to move as rapidly as possible to manage flows over heavily loaded flowgates up to their (post-contingency) operating security limits so as to use 100 percent of each flowgate's capacity. We believe this objective can be achieved at most, if not all flowgates. However, we will not compromise system

reliability to enhance transmission utilization. To evaluate what would be the effect of being unable to operate up to security limits under real-time dispatch, we ran a sensitivity case in which flowgate utilization was limited to 97 percent of capacity on all flowgates. In this case, the net cost of the TORC option, in comparison to continued participation in the Midwest ISO, fell from $43.9 million per year to $42.1 million per year, a 4 percent reduction in net costs. See Tables 6 and 7.

2. GFA Carve Out: In its September 16, 2004 Order, the FERC directed the Midwest ISO to physically carve out certain Grandfathered Agreements (GFAs) from the operation of the EMT.[33] LG&E/KU are beneficiaries of two of these contracts, GFA # 220 under which they also provide service to East Kentucky Power Cooperative and GFA # 222 that provides LG&E/KU access to its share of the output of Electric Energy Inc.'s Joppa Generating Station. The GFA carve out has three potential effects. First, to the extent LG&E/KU load is served under carved out agreements, LG&E would not pay congestion costs.[34] Second, some of these agreements will limit the redispatch options available to the Midwest ISO. Third, in some cases, carved out GFAs could affect the allocation of FTRs. We modeled the dispatch impacts, took into account the effects of LG&E/KU GFA carve outs on congestion costs and FTRs, and found that the carve out could reduce the net cost of the TORC option by $3.3 million per year or 7.5 percent under our conservative assumption about LG&E/KU's FTR allocation. However, when we made a very unfavorable assumption about FTR coverage of congestion costs – 75 percent coverage in the base case and 65 percent coverage in the GFA carve out case – the

---

[33] *Midwest Independent System Operator, Inc.*, 108 FERC ¶ 61,236.

[34] Additionally, GFA agreements will also be exempt from marginal loss charges. Such charges will go into effect for other existing transmission contracts after the five year transition period established in FERC's Order of August 6, 2004, 108 FERC ¶ 61,163.

cost of the TORC option was higher when the GFA carve out was taken into consideration. See Tables 6 and 8.

3. High Fuel Costs: Assuming a 20 percent increase in coal, oil, and natural gas costs from projected 2005 levels increased the cost of the TORC option, relative to Midwest ISO participation, from $43.9 million per year to $47.2 million per year. See Tables 6 and 9.

4. Low Fuel Costs: Similarly, a 20 percent reduction in forecast coal, oil, and gas prices lowered the expected cost of the TORC option from $43.9 million to $35.9 million annually. However, when we overlaid a very unfavorable assumption about FTR coverage the results of the base case, high fuel cost, and low fuel cost cases converged such that the difference between the three cases in projected cost of the TORC option was only $339,000. See Tables 6 and 10.

5. Benchmarking to Historical Off-System Sales: In our base case analysis, we made a very conservative assumption about hurdle rates – an input that keeps the model from overstating the economic efficiency of existing bilateral markets. I will discuss this assumption further at a later point in my testimony. However, we also analyzed the level of hurdle rates that would be needed to benchmark the model such that when we modeled a historical year (in this case 2003), modeled transaction levels would approximate those actually observed for that period. To benchmark our model to actual levels of off-system sales required increasing the hurdle rate from our conservative assumptions. When we then applied the higher hurdle rate to our TORC run for 2005, the model forecast a level of LG&E/KU off-system sales of 4,196 GWH per year, which is comparable to the actual volumes of 3,754 GWH in 2002 and 4,381 GWH for 2003 reported in Mr. Gallus' testimony and more than 50 percent lower than the volumes forecast for the TORC

option in our base case analysis.[35] Substituting off-system sales volumes that were representative of recent historical experience for the more conservative levels used in our base case analysis significantly increased the projected cost of the TORC option. Benchmarking our model to LG&E/KU's recent actual trading experience increased the projected cost to the Companies and their customers of withdrawing from $43.9 million to $71.1 million per year, an increase in projected costs of more than 60 percent. Please refer to Tables 3, 6, 9, and 11. This result strongly suggests that our base case results may significantly understate the cost of the leaving the Midwest ISO.

We then overlaid on our base case and each of the five additional sets of inputs more and less favorable assumptions regarding FTR allocations. The final FTR allocations that will be available to LG&E/KU will not be known until we get closer to the start of the market.

To illustrate the potential savings available to the Companies from the FTR allocation process, we analyzed the April illustrative FTR allocation without the conservative assumption that LG&E/KU would have to take money losing counter flow FTRs. In this FTR valuation, we followed the Midwest ISO's FTR nomination process and assumed that LG&E/KU would nominate and receive only those FTRs that were "in the money" for the season and peak or off-peak period in question. Given our remaining base case model inputs, this more favorable FTR allocation increased the potential recurring costs of the TORC option to $74.7 million per year. See Tables 3 and 6.

To bound the lower end of FTR allocation values, we examined what would be the impact of LG&E/KU receiving FTRs which covered only 65 percent of their congestion costs in the GFA carve out case and 75 percent of their congestion costs

---

[35] Supplemental Testimony of Martyn Gallus at 9.

in the remaining cases. I want to emphasize that this is highly unlikely to occur. In their analysis, the Companies assumed that they would receive sufficient FTRs to cover 95 percent of their congestion costs.[36] Even with this very low level of FTR coverage, the TORC option could cost LG&E/KU consumers $14.3 million per year more than remaining in the Midwest ISO. Again, see Tables 3 and 6.

Finally, we considered what would be the impact if there turned out to be no net transmission revenue benefit to remaining within the Midwest ISO. This permitted us to develop a "worst case" scenario in which the volume of LG&E/KU off-system sales under the TORC option reached levels that are assumed to be more than double recent historical experience, the Midwest ISO's real-time dispatch fails to achieve anticipated levels of transmission utilization, the value of LG&E/KU FTRs are unexpectedly very low when compared to congestion costs, and LG&E/KU receives no net transmission revenue benefit from continued Midwest ISO membership. Even when we applied assumptions that were highly biased in favor of the Companies withdrawing from the Midwest ISO, the recurring costs of withdrawing to pursue the TORC option totaled more than $5.3 million per year. See Tables 6 and 7. This figure does not take into account the $40.2 million exit fee the Companies would have to pay to leave the Midwest ISO in January 2006.

Considering the conservatism of our base case analysis and broad range of sensitivity cases analyzed, the Commission can have a very high degree of confidence that remaining in the Midwest ISO will be significantly less costly for LG&E/KU and its customers than any of the other available options.

Q. YOU INDICATED THAT THERE ARE SIGNIFICANT INTERMEDIATE AND LONG-TERM BENEFITS ASSOCIATED WITH LG&E/KU'S PARTICIPATION IN THE MIDWEST ISO. DID THE ADDITIONAL ANALYSIS PREPARED FOR

---

36 Supplemental Testimony of Mathew Morey at 44-45.

THIS TESTIMONY PROVIDE ADDITIONAL INFORMATION REGARDING THOSE BENEFITS?

A. Yes. The intermediate and long-term benefits are described in greater detail in Exhibit RRM-1 attached to my direct testimony in this proceeding. And, while our analysis prepared in response to the Company's Supplemental Testimony largely focuses on near-term impacts, we identified a frequently occurring pattern in the location specific prices for the LG&E/KU system. In this pattern, prices at LG&E/KU's Trimble County facility were often lower than those at LG&E/KU generating sites downstream from frequently encounter constraints within the LG&E/KU system. If LG&E/KU stay in the Midwest ISO, actual market prices may confirm and add additional information regarding scope and frequency of occurrence of this price pattern.

The pattern which we observed has important and lasting implications for LG&E/KU's investment in generating capacity. For example, our analysis suggests that, given operating patterns typical of LG&E/KU combustion turbines, the value of combustion turbine at the Ghent plant site, for example, would be nearly $1 million per year higher than what could be earned or the costs that could be avoided if that generator were placed at Trimble County. If the LG&E/KU system were viewed as an island onto itself, this result would appear counter intuitive given that Trimble County is closer to LG&E/KU's largest load center. However, when the efficient management of regional power flows are taken into consideration, LG&E/KU will have significant opportunities to improve the return on their long-term capital investments and reduce costs for ratepayers.

Q. YOU HAVE MENTIONED THE UNIQUE POSITION THAT THE LG&E/KU TRANSMISSION SYSTEM OCCUPIES IN THE TRANSMISSION GRID FOR EASTERN NORTH AMERICA, WOULD YOU PLEASE DESCRIBE WHAT THAT POSITION IS?

A. The LG&E/KU system is not an island. Given its central location, the LG&E/KU system plays an important and at times limiting role in power flows from West to East and from South to North and North to South. LG&E/KU transmission flowgates account for a disproportionate percentage of transmission constraints within the Midwest ISO footprint – approximately 9 percent of all flowgate hours spent in Level 3 or higher TLR events on which the Midwest ISO gathered power flow data during 2003. Many of these events are not primarily the result of internal power flows from LG&E/KU generators to LG&E/KU loads, but reflect loop flows through the LG&E/KU system. When congestion occurs in an isolated system, LMPs at the load centers increase relative to generation LMPs to reflect congestion costs. In our analysis, we found that the opposite pattern occurred with some frequency in the LG&E/KU system because of the externally caused loop flows. In several cases, average hourly LG&E/KU generation LMPs exceeded average hourly LG&E/KU load LMPs in more than 200 hours per year. In our base case model run, generation LMPs were higher than load LMPs in 312 hours by an average amount in those hours of $1.26 per MWH. Appendix B illustrates the conditions of the system during two of those hours. In these circumstances, major LG&E/KU loads, particularly in the Louisville area, are located on the upstream or low price side of transmission constraints, while major generating stations including the Ghent, Brown, Tyrone, and Green River plants are just on the downstream or high price side of the constrained flowgates.

In these circumstances, being within the Midwest ISO's regional economic dispatch provides significant benefits to LG&E/KU and its customers that would not be available under any other option. First, major LG&E/KU load centers will benefit from low LMP prices and low or negative congestion costs. Second, major LG&E/KU generators would have an opportunity to sell additional energy into the Midwest ISO markets at high LMPs as increased generation at their locations would create counter flows to alleviate the transmission constraints. Regional management of the constraints and power flows on the LG&E/KU system thus creates additional opportunities for LG&E/KU generators to make off-system sales at higher prices than would be available in bilateral markets that were not fully integrated with the operation of the transmission system. Third, only through centralized dispatch and the coordination of power flows for the region as a whole is it possible to develop an economically efficient dispatch response to such loop flows. Because the flows originate outside the LG&E/KU system, under the TORC option it would be impossible for LG&E/KU to efficiently manage much of the transmission congestion found in the LG&E/KU system. The Companies or their reliability coordinator would be forced to rely on a TLR based system of congestion management, which, as I discuss elsewhere in my testimony, is highly imprecise and economically inefficient.

The principal conclusion of our analysis is that the LG&E/KU transmission system is not an island and the Companies and their customers will pay a significant cost penalty if they attempt to operate the system as if it were only loosely connected to the Midwest region when that is not in fact the case.

Q. IS THIS A DIFFERENT PERSPECTIVE ON THE COMPANIES' POSITION IN THE GRID THAN THAT TAKEN BY COMPANY WITNESS TIERNEY, WHICH FOCUSES ON LG&E/KU BEING A LOW COST UTILITY?

A. Yes. The Companies have presented an overly simplified and generation centric perspective. For purposes of determining whether it makes sense for LG&E/KU to continue to have its transmission system managed by the Midwest ISO, it is necessary to see the Companies' position in the grid from a transmission operations perspective. This perspective focuses on the factors which actually influence the economics of participation in a centralized dispatch RTO, including: the areas with which the system is most closely interconnected, the location of constraints, regional power flows which may loop through the system whether or not it is included on the contract paths for such flows, and the diversity – not simply the average cost - of generation. In the case of LG&E/KU, these factors strongly favor participation in an RTO with regional dispatch. Coordinated management of regional power flows that loop through their system and the resulting transmission constraints will help the Companies take better advantage of their low cost resources, while making available intermediate priced generation to fill in the substantial gap that exists in their dispatch stack after the low cost coal plants have been fully dispatched.

B. Benefit – Cost Analysis Methodology

Q. HOW DOES THE STUDY THAT SUPPORTS THIS TESTIMONY DIFFER FROM THE STUDY THAT ACCOMPANIED YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. There were major updates and enhancements in the analysis that accompanies my testimony today. These include:

1. My testimony today reflects FERC's approval of the Midwest ISO EMT and quantitative analysis of various FERC orders on tariff implementation including consideration of Orders related to the treatment of Grandfathered Agreements and Narrow Constrained Areas.
2. Our analysis was based on an updated and enhanced power flow model for 2005, which facilitated a more accurate analysis of the role of centralized dispatch in managing power flows across the LG&E/KU system.

3. My testimony includes an analysis of a four tier illustrative FTR allocation that incorporated stakeholder input and better reflected the manner in which the final FTR allocation will be developed.

4. Our updated modeling reflects the results of an analysis of transmission utilization under all 2003 Midwest ISO Level 3 or higher TLR events in the Midwest ISO for which actual power flow data is available.

5. Our study incorporates updates to model inputs such as fuel costs and transmission upgrades and updates to exit fees and other cost information.

Additionally, my testimony incorporates an extensive analysis of uncertainty factors and enabled me to conclude that there are no plausible circumstances under which it is likely that LG&E/KU could reduce their costs of serving load by withdrawing from the Midwest ISO.

Q. CAN YOU PLEASE SUMMARIZE THE ANALYSIS THAT WAS PERFORMED?

A. We completed a detailed production costing and power flow analysis of the cost to LG&E/KU and its customers of withdrawing from the Midwest ISO to pursue the TORC option and of the Midwest ISO continuing to manage the operation of the LG&E/KU transmission system under the Midwest ISO EMT. In addition to the description given here, Appendix C provides further information about the analysis.

This analysis was conducted using the PROMOD IV® model, which integrates hourly chronological production costing and detailed power flow analysis. The EMT, TORC, and current (Day 1) operation cases were based on identical input assumptions related to loads, generator costs and characteristics, forecasted fuel[37] and emissions credit prices, and a base case power flow. The model included a representation of power system operations and considered, in its security-constrained unit commitment and

[37] Oil and gas price forecasts reflect forward prices on the New York Mercantile Exchange adjusted for regional geographic basis differentials. Our analysis included high and low fuel price sensitivity cases in which all natural gas, oil, and coal prices were increased or decreased respectively by 20 percent.

dispatch and identification of cost-effective trades, power flows for most of the Eastern Interconnect. The Eastern Interconnect is the largest power grid in North America extending from Florida to Northern Texas and the Dakotas to Quebec.[38] Our model included representations of more than 5,000 generating units, 40,000 transmission buses, and 50,000 transmission lines. It was used to project production costs and location-specific hourly market clearing prices. The model calculates and can track location-specific, hourly prices for up to 8,000 specific locations.

The modeling analysis was used to quantify differences between alternative futures based on modeling a representative time period. In this case, we selected calendar year 2005. Given the level of detail necessary to properly represent the relationship between how power flows are managed and the cost to serve load, the selection of a representative year for modeling of this type is a generally accepted to be a reasonable practice given the type of circumstances present in this case. There is no reason to believe that the difference between the cost to serve load under the TORC option and in the Midwest ISO will change materially over the period 2005 through 2010.

Q. WHAT ARE THE PRIMARY FACTORS DISTINGUISHING THE EMT AND TORC MODEL RUNS?

A. The are three primary factors that distinguish how the transmission system and energy markets will perform under the EMT from both current operations and what LG&E/KU would experience operating on a TORC basis. First, in the TORC case, we represented the expected maximum utilization of monitored flowgates during periods of transmission congestion based on the historical average utilization of flowgates during TLR events. Second, we reflected appropriate tariff rates in modeling opportunities for economic purchases and sales in all cases. These rates comprise the first of two components of

---

38 The model included simplified representations of the Northeast Power Coordinating Council and Florida Reliability Coordinating Council regions, which were based on more detailed modeling of those regions.

what is known as a "hurdle rate." Hurdle rates are used in such modeling to keep the model from over optimizing and representing a level of economic transactions that cannot be maintained under current operating practices. Third, the inherent inefficiencies of reliance on a bilateral market that is not closely integrated with the operation of the transmission system is reflected in a second hurdle rate component, which takes into account both transaction and lost opportunity costs. We specified hurdle rates that were conservative in that when we ran the model with our conservative hurdle rates for a historical period (2003), the model produced a larger overall volume of economic purchases and sales for LG&E/KU and other Midwest ISO control areas than had actually occurred during that historical period.

Q. HOW DID YOU REFLECT THE LIMITS ON EXPECTED MAXIMUM FLOWGATE UTILIZATION?

A. When operating outside of a market based on regional, security-constrained, economic dispatch, the maximum amount of transmission capacity that can be effectively utilized is limited by the imprecision and inefficiency of current approaches to congestion management that rely on physically rationing transmission capacity through calculations of Available Flowgate Capacity ("AFC") and physical curtailments under the North American Electric Reliability Council's ("NERC's") TLR procedures. As I described in my direct and supplemental testimony in this proceeding, this results in under utilization of transmission capacity even when the desire to utilize the transmission system exceeds its capabilities.

To better understand the extent of this under utilization, the Midwest ISO has extended the analysis that described in my direct and supplemental testimony to include all Level 3 or higher TLR events in the Midwest ISO footprint during calendar year 2003.

The results of that analysis were reflected in our modeling by reducing the capacity of monitored flowgates to the levels actually observed during TLR events in 2003.[39]

Under the Midwest ISO's EMT, bids and offers will be accepted in real-time based on analysis of actual and post-contingency power flows. This will allow the Midwest ISO to match the resulting power flows over constrained flowgates to operating security limits. More precise management of power flows in the real-time market will permit the Midwest ISO to approach full utilization of available flowgate capacity. Thus, we did not derate the effectively available flowgate capacity in the base case analysis of the EMT option. A sensitivity analysis was performed to test what would be the impact if the Midwest ISO was unable to achieve its post-EMT operating objective of full flowgate capacity utilization.

Q. HOW DID YOU DEVELOP THE HURDLE RATES USED IN YOUR ANALYSIS?

A. We began by identifying the actual through-and-out transmission charges for the key dispatch pools in our analysis. We then added to these individual pool hurdle rates a $3 per MWh transaction and lost opportunity cost component. This value for this additional component was based on benchmarking the model against actual historical performance. This initial benchmarking exercise indicated that a value for transaction and opportunity cost of at least $3 per MWh or more was necessary. At a $3 per MWh adder for transaction and lost opportunity costs, the volume of transactions produced by the model exceeded those that had been historically observed based on an analysis of net interchange among control areas in the Midwest ISO footprint. See Appendix C, page 4.

We subsequently ran a sensitivity case, which raised the LG&E/KU hurdle rate to a level that would be necessary for the model to produce a level of transactions that approximated actual levels of LG&E/KU off-system sales. As indicated earlier in my

[39] Flowgate capacity in the LG&E area was reduced by 9 percent. The reductions to flowgate capacity varied based on results for different portions of the region.

testimony, in this sensitivity case, the cost of TORC operation is significantly higher than what is reflected in our base case analysis. Please refer to Table 11. This sensitivity case confirms that our base case forecast of TORC costs may be lower than what LG&E/KU might actually experience.

Q. WHAT FACTORS ARE TAKEN INTO CONSIDERATION BY THE TRANS-ACTION AND LOST OPPORTUNITY COST PORTION OF THE HURDLE RATE?

A. The transaction and opportunity cost portion of the hurdle rate was selected to reflect to cumulative impact of several inherent inefficiencies in bilateral contract markets, including:

- The inability of markets that are not tightly integrated with the operation of the transmission system to identify all cost-effective transactions.
- Current utility practice that tends to reflect a bias, which may be appropriate given the lack of a liquid spot market, towards commitment of each utility's own generation to serve its native load.
- Existing scheduling procedures limit market participants to whole hour or longer transactions. By contrast, the Midwest ISO energy markets will be able to optimize the operation of generation across member utilities at least every five minutes.
- Finding a cost-effective mix of purchases and sales requires bilateral negotiations with multiple other market participants. Such negotiations and the resulting transactions impose transaction costs related to the search for cost-effective transactions, negotiations, contracting, scheduling, settlement, managing counter-party risk, and dispute resolution. These transaction costs are a direct cost to bilateral market participants. They are either largely avoided (*i.e.*, search, negotiations, contracting, and dispute resolution) or covered by the Midwest ISO

charges (*i.e.*, scheduling, settlement, and counter-party risk management) under the Midwest ISO's EMT.

- In such power trading negotiations, each participant has an incentive to limit its disclosures to counter parties to maintain its advantages arising from the asymmetric information availability and capture as large a portion of the benefits from the transactions as possible. Given imperfect information and a non-transparent market, identifying a cost-effective mix of transactions takes time and not all economic transactions will be discovered.
- Given a lack of transparency, geographic price spreads occur in bilateral markets that do not reflect genuine differences in locational marginal costs. These spreads create misleading operating incentives that may fail to mitigate and in some cases exacerbate transmission congestion. The lack of transparency has direct cost impacts and secondary cost impacts through its failure to efficiently alleviate transmission congestion.
- Power markets are highly dynamic. Given the transaction costs and the time involved in completing bilateral transactions, the utilities' generation, purchases and sales are seldom fully optimized given continuously changing conditions.

Q. CAN YOU SUMMARIZE WHY YOU HAVE SELECTED THIS MODELING APPROACH AND THE FACTORS THAT WERE USED TO DISTINGUISH THE EMT FROM NON-EMT OPERATIONS?

A. The transmission system in the Midwest cannot simultaneously accommodate all reservations and requests for transmission service. System operators have to perform a complex task of managing congestion to keep power flows within operating security limits. When that task is performed efficiently, resources are committed and dispatched and the transmission system may be reconfigured to optimize economic outcomes subject to meeting reliability-based limits on power flows.

The electric power system has unique characteristics that increase the complexity of congestion management:

- Power flows can change instantaneously. Following the laws of physics, when load, generation, or transmission facilities change, power flows immediately redistribute themselves along the paths of least impedance.
- Within the short time frames that are critical for managing such flows, the transmission system in large part lacks the capability to operate as a switched network. Thus, unlike a telephone call that can be rerouted when a line goes out of service, power system operators have limited direct control about where power will flow when a line or transformer fails.
- Given that power flows will change at near the speed of light in the event of an equipment failure, operators would be unable to respond with sufficient speed if each element in the system were loaded up to its individual thermal limit. Therefore, the transmission system is operated on a contingency basis. That means the security limits on the use of specific transmission lines must be based not only on the physical capabilities of each line, but on how the flows over that line would change in the event of the failure of other transmission facilities.
- A single transaction from point A to point B produces a distribution of power flows that can affect transmission paths across a broad region of the grid. The changing overall pattern of generation, load, and transmission facilities in service determines which paths will be impacted. And in some circumstances, a power transfer in one part of the grid can produce a disproportionate impact on the ability to move power in a geographically distant portion of the system.
- Changing the location at which power is generated is the primary mechanism used to manage power flows within security limits. Thus, efficiency with which congestion in the transmission system is managed is a direct function of the scope

> and efficiency with which generation can be re-dispatched to accommodate transmission constraints. By facilitating the economic re-dispatch of generation in response to transmission constraints on a region-wide — not just a local — basis, the Midwest ISO energy markets are expected to significantly reduce the costs of congestion management.

The implications of these complexities cannot be captured in a simple model that treats the transmission system as a set of pipes with fixed capacities. It is necessary to select an appropriately complex model that can reflect the impact of such factors to evaluate how regional security-constrained economic dispatch can impact economic outcomes and opportunities to make cost-effective market purchases and sales.

We have used a model that, much more effectively than the models strung together in the Companies' analysis, can capture in an integrated fashion the impact of such effects.

In order to provide a conservative representation of the differences between TORC and EMT operations, we have actual data on recent transmission capacity utilization to set the maximum effective capacity of the system. And, we have selected conservative hurdle rates that actually allow the model to select a larger number of cost-effective transactions in the TORC cases than LG&E/KU has ever been able to achieve in practice. Thus, our approach very likely understates the costs of LG&E/KU leaving the Midwest ISO to pursue the TORC option.

C. <u>Assessment of Companies' Benefit – Cost Analysis</u>

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN YOUR CONCLUSIONS REGARDING THE BENEFITS OF MIDWEST ISO MEMBERSHIP AND THOSE PRESENTED BY THE COMPANIES' WITNESSES.

A. While there are a number of smaller differences between the Midwest ISO's analysis and that presented the Companies' supplemental testimony, there are three major issues on which the studies diverge where the Companies have failed to conduct an appropriate analysis. Those issues are:

1. The selection and structure of models for analyzing the economic effects of regional transmission operations and dispatch;
2. The inefficiencies inherent in bilateral power markets that are not closely integrated with transmission system operations; and
3. The distribution of transmission revenues under the Midwest ISO tariffs.

Q. HOW DO THE STUDIES DIFFER IN THE SELECTION AND STRUCTURE OF MODELS USED TO ANALYZE REGIONAL TRANSMISSION OPERATIONS AND DISPATCH?

A. The use of models described in Mr. Gallus' supplemental testimony and relied upon to support Mr. Gallus' and Mr. Morey's conclusions is simply inappropriate for purposes of assessing the benefits and costs of centralized regional dispatch and regional management of the transmission system. The models selected by Mr. Gallus were not designed for this purpose and cannot be expected to identify more than a small fraction of the benefits of regional congestion management and increased opportunities for utilities in the position of LG&E/KU to increase off-system sales.

To understand this point, let us begin with Mr. Gallus' description of his modeling effort. He states that: "Three software packages were used to perform this analysis. MIDAS Gold ("MIDAS") was used to generate the electricity price forecasts. PROSYM was used to evaluate the Companies' cost to serve native load and off-system sales margin production cost revenue requirements. MUST was used in the calculation of transfer limits used in both MIDAS and PROSYM." We can see, first, that Mr. Gallus is not using one integrated model to consider both regional and local prices and costs. MIDAS appears to have been used to estimate prices in the LG&E/KU control area and for other control areas within the region. A second model, PROSYM, was then used to calculate LG&E/KU generation costs and, by deducting these costs from prices calculated in MIDAS, to determine margins on off-system sales. To understand the limitations of his analysis, however, one needs to know something about the models he used. MIDAS is a production costing and financial analysis model often used to rapidly analyze a range of different scenarios under conditions of uncertainty. To facilitate more rapid scenario analysis and incorporate the model's financial focus, MIDAS makes compromises in its representation of the transmission system. Transmission is represented primarily as a set of fixed capacity interfaces between control areas. If one were conducting a financial analysis related to the operation of a single control area under stable conditions with respect to regional energy markets and few internal transmission constraints, this type of representation of the transmission system for some purposes might be sufficient. However, MIDAS does not integrate production costing and detailed power flow modeling. The PROSYM model identified by Mr. Gallus, according to his testimony, was used to calculate the Companies' costs. It appears to have been used to quantify only the costs of operating the LG&E/KU control area. While PROSYM's vendor does offer a multi-area model, there is no indication that Mr. Gallus used that model or applied PROSYM to evaluate system operations outside the LG&E/KU control area. MUST is a model that allows the analyst to input a specific power flow and assess the appropriate transfer limits for a set of transmission facilities. It is not generally used to assess the economic implications of regional versus local unit commitment and dispatch or analyze power markets. What is missing in the combination of models deployed by Mr. Gallus is any reasonable capacity to analyze the relationship between detailed regional power flows and regional economic dispatch. In effect Mr. Gallus has built into the set up of his models the assumption that LG&E/KU operates as an island connected to the surrounding region with interfaces that have fixed capacities, with purchasing from and selling to adjacent entities at prices that do not change based on the operation of the LG&E/KU system. These assumptions, which are inherent in the way in which Mr. Gallus designed his modeling, are simply false.

While historically, given limited trading between utilities, one might get by for some purposes with a simplifying assumption of fixed interface capacities between control areas, this is just not the way power systems operate. As illustrated for simple network in Appendix A can change significantly depending on the selection of generating capacity operating at that time.

Moreover, under the Midwest ISO EMT, when one moves out of a bilateral trading model in which available transmission capacity is physically rationed to an LMP market in which prices reflect congestion on the transmission system. The selection of which generators operate in one control area may increase or alleviate a transmission constraint that in turn changes power prices in neighboring control areas. These prices change with the dispatch of generation because the market is reflecting the value of generation and load at specific nodes within the transmission grid.

The production costing model used by Mr. Gallus to calculate regional prices was not designed to adequately capture either of these effects. By contrast, the Midwest ISO's analysis used the PROMOD IV® model which integrates a detailed power flow model with chronological production costing. In so doing, our model captures the effects of changing power flows on interface capacity and location-specific prices. As a result, PROMOD sees opportunities to improve the efficiency of system operations and make economic power purchases and sales that simply would never be identified by the models Mr. Gallus has employed. While PROMOD is an hourly model and will not identify the additional opportunities to improve system operations through the Midwest ISO's 5-minute redispatch, it much more closely approximates the operation of the Midwest ISO power markets. PROMOD is a more detailed model - requiring more than 70 hours of continuous run time to complete each one-year simulation - that was designed to analyze the type of operating efficiencies achieved through regional economic dispatch and congestion management.

Q. HOW SHOULD THE COMMISSION EVALUATE MR. GALLUS' PRODUCTION COSTING ANALYSIS?

A. Given that Mr. Gallus relied on models that are inappropriate for analyzing the primary issues in this proceeding, whether regional security-constrained economic dispatch that is integrated with regional operation of the transmission system will produce economic benefits for LG&E/KU, the Commission should give no weight to the results of his production costing analysis for purposes of answering the key questions in this proceeding.

Q. HOW DOES THE COMPANY'S REPRESENTATION OF THE ECONOMIC INEFFICIENCIES INHERENT IN A BILATERAL MARKET WITHOUT COORDINATED ECONOMIC DISPATCH DIFFER FROM YOUR ANALYSIS?

A. As I discussed earlier in my testimony, there are three primary factors that permit multi-area models to develop a reasonable representation of power purchases and sales. First, flowgate capacities can be limited to reflect the ability given the prevailing congestion management system to actually use the physical capacity of the system. For our analysis, we have set those limits based on a comprehensive study of actual transmission utilization during all Level 3 TLR events in the Midwest ISO for which data was available. Second, it is necessary to reflect any transmission charges that would affect the economics of purchasing power from another control area versus generating that power locally. These charges become the first of two components of what is called a "hurdle rate." The hurdle rate is the minimum economic value that a transaction must provide before it will be executed in the model. We have used actual tariff rates for all key entities in and adjacent to the Midwest ISO footprint, while the Companies have assumed a flat $3 per MWh on-peak and $2 per MWh off-peak tariff charge for all areas.

Finally, it is customary to add an additional component to the hurdle rate to reflect the inefficiencies inherent in trading power bilaterally. This second component I have referred to as the transaction and opportunity cost component. For our base case analysis, we have set this second component of the hurdle rate at $3 per MWh. Other analysts often use much higher hurdle rates, but we have sought to be conservative so as to not overstate the benefits of Midwest ISO energy markets. The fact that we have been very conservative is evident in the fact that our analysis assumes that, even if it were to pursue the TORC option outside of Midwest ISO, LG&E/KU would have much higher off-system sales than they have today or what is assumed in the Companies' analysis. The Companies have used only a $1 per MWh transaction component in their hurdle rate. They have applied this additional component not only to bilateral transactions – where it may be appropriate to apply a higher transaction and opportunity cost element in the hurdle rate, but also to centralized dispatch within the Midwest ISO pool. This application of a hurdle rate component designed to capture the inefficiencies of having to rely on bilateral transactions to the modeling of regional security-constrained economic dispatch is clearly inappropriate. There is no such hurdle rate in the unit commitment and dispatch algorithms that will be used by the Midwest ISO to operate its Day-Ahead and Real-Time Energy Markets.

My primary concern with the way Mr. Gallus' models reflect the inefficiencies of bilateral energy markets, however, is more fundamental. It is that the models he has used were not designed to enable an analyst to see the opportunities for economic transactions that become available when the operation of transmission and power markets are closely integrated and would occur as a result of the Companies' participation in the Midwest ISO energy markets. Because his multi-area model – MIDAS – uses fixed transfer limits that are inappropriate for answering the questions before the Commission and his approach appears to assume that the dispatch of generation in LG&E/KU – which he models in PROSYM – will not materially affect prices for off-system purchases and sales – prices that he took from MIDAS, his analysis simply never recognizes the additional opportunities to purchase and sell power that become available when power flows are managed on a regional level and integrated with energy markets through regional economic dispatch. This is self-evident in the fact that our model, that was designed to identify these opportunities, forecasts much higher transaction volumes for LG&E/KU, on both a stand alone basis and when in the Midwest ISO, than does Mr. Gallus' model – even though we have used higher hurdle rates and similar or more restrictive limits on the use of transmission capacity.

Q. MR. GALLUS TESTIFIES THAT HE BELIEVES THAT LG&E/KU IDENTIFIES ALL TRADES BETWEEN WILLING TRADING PARTIES AND REFERS TO ITS USE OF THE ELECTRONIC BROKER "ICE" AND SEVERAL DIRECT BROKERS TO IDENTIFY AND EXECUTE POSSIBLE TRANSACTIONS. WOULD YOU PLEASE COMMENT ON HIS CONCLUSIONS?

A. First, none of these trading mechanisms – the Inter-Continental Exchange ("ICE") or private brokers – are closely integrated with the operation of the transmission system. Thus, even if any individual broker had – and no single broker or utility does have – knowledge of the price bids for all generators, they would not be able to put together an optimized portfolio of transactions. Every transaction affects power flows and thus what should be the market clearing price for power at other locations on the grid. So, even if Mr. Gallus' assertion were credible and the Companies were omniscient with respect to every possible transaction that others would be willing to enter, knowing the trades that parties might be willing to make would not be the same as knowing the trades that would be economically efficient to make given the dynamic power flows and how the operation of the transmission system affects the value of power at various locations on the grid.

Second, while the mechanisms mentioned by Mr. Gallus are useful and identify many cost reducing transactions, it is simply not reasonable to believe that brokered bilateral markets will identify all potential cost-reducing transactions. Unlike buying a house or a car, the economic value of power is location-specific, dependent on all other power flows through the grid, reflects the real-time management of the transmission system, and changes continuously.

Third, today brokers and traders have an incentive to not disclose the true economic cost or value of power because non-disclosure allows them to exploit their information advantages over counter parties to increase their margins on individual transactions. Parties to transactions have asymmetric information because there is no transparent centralized market that is integrated with operation of the transmission system. While the use of perceived information advantages may benefit individual traders and brokers in the context of a specific transaction, it depresses the number of cost-effective transactions that can be completed and prevents opportunities for cost reduction from being realized.

Finally, our analysis demonstrates that Mr. Gallus' assumption that he is identifying all cost effective transactions is simply wrong. Even when we build into the model a hurdle rate that reflects $3 per MWh in transaction and lost opportunity costs, the model identifies a volume of cost-effective off-system sales that is approximately double the volume sales that LG&E/KU have been making in recent years.

Q. WHAT IS YOUR CONCERN WITH THE COMPANIES' TREATMENT OF TRANSMISSION REVENUES UNDER THE MIDWEST ISO OPTION?

A. Company witness Morey states that, "With respect to transmission revenues associated with providing PTP [point-to-point] service, there is not likely to be a significant difference among the several options since the major user of the Companies' grid will be its own generation division in making off-system sales into the Midwest ISO/PJM combined market or outside of that footprint, predominately to TVA."[40] For those cases when LG&E/KU is outside the Midwest ISO, the Companies' witness is correct in the limited sense that other entities are not likely to contract for transmission service through LG&E/KU. The LG&E/KU system is surrounded by much larger interconnected markets and transmission providers. Under the TORC option, LG&E/KU transmission revenues would be based on whether LG&E/KU transmission facilities were on the "contract path" used to schedule a given transaction. And third, parties would not need to pay for such an extra link in their transmission path through the LG&E/KU system. Thus, the transmission revenues that LG&E/KU would receive under the TORC option are likely to be limited to revenues associated with the Companies' own off-system sales. However, given that the transmission customer's selection of a contract path does not change the physical flow of power, LG&E/KU would continue to experience loop flow associated with third-party transactions for which it would not be compensated under the TORC option.

The Company is incorrect in its characterization of the distribution of point-to-point transmission revenues when LG&E/KU is within the Midwest ISO. The Transmission Owners Agreement governs revenue distributions within the Midwest ISO. Based largely on the systems impacted by the physical power flows and the relative level of transmission investment of different member systems, the Midwest ISO distributes certain point-to-point transmission revenues under a pooling formula which results in payments to LG&E/KU that substantially exceed the transmission revenues that LG&E/KU would earn if point-to-point transmission revenues reflected only revenues associated with LG&E/KU off-system sales. Moreover, because the pooling arrangements reflect actual power flows, not a fictional "contract path," LG&E/KU is

---

[40] *Supplemental Investigation into the Costs and Benefits to Louisville Gas and Electric Company and Kentucky Utilities Company of RTO Participation Options* (September 29, 2004), at 24 – 25.

compensated for the use of its transmission system regardless of whether or not its trading operation makes the sale. If, for example, a point-to-point transaction sourcing at Cinergy and delivered to Big Rivers Coop were to displace a sale from a nearby LG&E/KU generator, this would not change the Schedule 1, 7, 8, or 14 transmission revenues received by LG&E/KU as a Midwest ISO member.

Q. DON'T YOU HAVE TO DEDUCT FROM YOUR CALCULATION OF BENEFITS AND COSTS THE TRANSMISSION PAYMENTS WHICH LG&E/KU HAS TO MAKE WHEN IT COMPLETES AN OFF-SYSTEM POWER SALE AS AN OFFSET TO THE RECOGNITION OF TRANSMISSION REVENUES?

A. Yes. And, I have done so. In both my direct testimony and here my analysis has presented revenues from off-system power sales as revenues net of any transmission charges – that is after already deducting the cost of transmission payments.

Q. WOULD YOU PLEASE SUMMARIZE THE REMAINING IMPORTANT DIFFERENCES BETWEEN YOUR ANALYSIS AND THE BENEFIT – COST STUDY PRESENTED BY THE COMPANIES?

A. First, the Companies analysis inappropriately includes an increase in costs to LG&E/KU for a Schedule 21 uplift. The Schedule 21 proposal was intended simply to direct payments to independent power producers when they provide services for which control area operators were being paid. As it is being implemented, the Schedule 21 proposal does not create an uplift for and does not change the costs paid by LG&E/KU.

Second, Mr. Morey's report references the Midwest ISO's proposed use of marginal loss LMPs and rebate of surplus loss revenues to loss revenue pools.[41] The FERC's August 6, 2005 Order modified the application of the marginal loss methodology by requiring surplus loss revenues to be credited back to current market participants whose costs from marginal losses exceed average losses or their historical loss charges

[41] *Id.* at 19.

for a five year transitional period.[42] This effectively maintains the current approach in which all existing customers will pay for losses on an average loss basis. I have reflected this in my benefit – cost analysis.

Third, I have reflected in my results a $1.3 million per year increase in internal Administrative and General costs that the Companies assert would be associated with their participation in the Midwest ISO. However, the Commission may wish to consider two mitigating factors. First, the Companies will have already made most of the investments required to participate in the Midwest ISO energy markets. The Companies have been preparing for market start on March 1, 2005 and are obliged under the Transmission Owners' Agreement to remain in the Midwest ISO through at least the end of 2005. Investments made by the Companies to enable them to participate in the market are sunk costs and will not be avoided regardless of the outcome of this proceeding. Second, if the Companies participate in the Midwest ISO Day-Ahead and Real-Time energy markets, the security constrained economic unit commitment and dispatch algorithms that clear those markets will identify for LG&E/KU the most economic day-ahead and real-time purchase and sale opportunities for the location of their generators and given power flows across the region. While the Companies might elect to maintain day-ahead and real-time trading operations after March 1, 2005, it would be economic to do so only if such operations could out perform the Midwest ISO energy markets. All else being equal, the Companies should be able to reduce their Administrative and General costs in some areas by taking advantage of the efficiency of Midwest ISO Day-Ahead and Real-Time energy markets.

---

[42] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 at P 74 (2004).

Q. IN HIS TESTIMONY, MR. MOREY REFERS TO A TREND TOWARD INCREASING RTO COSTS; DOES THIS FAIRLY CHARACTERIZE LIKELY FUTURE DEVELOPMENTS IN TERMS OF THE COSTS THAT WILL BE PAID BY MIDWEST ISO MEMBERS?

A. No. Mr. Morey has identified increases in costs that are to a large degree associated with RTO start-up, RTOs expanding the services that they provide such as implementation of LMP and ancillary services markets or enhancing their monitoring of system reliability, or RTOs increasing the geographic scope of their operations such as the incorporation of new members into the Midwest ISO and PJM. As the RTOs mature, the cost of RTO operations will level off and should decline over time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

The answers in the foregoing testimony are true and correct to the best of my knowledge and belief.

Ronald R. McNamara

STATE OF INDIANA)

COUNTY OF HAMILTON)

Subscribed and sworn to before me by Ronald R. McNamara, on this the 19th day of November 2004.

Dorothy M. Shute

Notary Public

DOROTHY M. SHUTE
NOTARY PUBLIC, State of Indiana
My County of Residence: Hendricks
My Commission Expires: May 8, 2009

(SEAL)