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January 10, 2005

RECEIVED
JAN 1 0 2005
PUBLIC SERVICE COMMISSION

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

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

Dear Ms. O'Donnell:

Enclosed please find an original and ten (10) copies of Louisville Gas and Electric Company and Kentucky Utilities Company's Supplemental Rebuttal Testimonies of Paul W. Thompson, Martyn Gallus, Mark S. Johnson, David S. Sinclair, Mathew J. Morey, Susan F. Tierney and Michael S. Beer, in the above-referenced docket.

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Sincerely,

Kent W. Blake

Kent W. Blake

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

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

Filed: January 10, 2005

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

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

Q. Have you previously testified in this proceeding?

A. Yes. I offered both direct and rebuttal testimony in the initial phase of this proceeding and testified at the hearing on February 25, 2004, and submitted supplemental direct testimony on September 29, 2004 in the second phase of the Commission's investigation.

Q. What is the purpose of your rebuttal testimony?

A. I will provide a general overview of the Companies' rebuttal case in this phase of the proceeding. I will particularly emphasize rebuttal concerning the Midwest Independent Transmission System Operator, Inc.'s ("MISO") flawed cost-benefit analysis, which is the sole, faulty foundation for MISO's erroneous assertion that revenues associated with the Companies' continuing MISO membership will exceed the costs thereof. I will also rebut MISO's assertion that continued MISO membership is the best course for the Companies and their customers.

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

A. In addition to my testimony, the Companies offer the testimony of a number of other witnesses as part of their rebuttal case:

- Martyn Gallus will rebut Dr. McNamara's contentions that MISO's use of centralized Security Constrained Economic Dispatch ("SCED"), Locational Marginal Prices ("LMPs"), and Financial Transmission Rights ("FTRs") will have a favorable impact on the Companies' marketing operations, dispatch, and overall business.
- Mark S. Johnson will rebut Dr. McNamara's contention that if the Companies withdrew from the MISO there would be an adverse impact on reliability and will demonstrate that the Companies could engage the services of a third party for security coordination without exposing the Companies' customers to significant new reliability risks.
- David S. Sinclair rebuts Dr. McNamara's criticisms concerning the software models used by the Companies to support their cost-benefit study and explains the noteworthy error MISO made by including Western Kentucky Energy ("WKE") and Dynegy generation units in MISO's model of the Companies' dispatch.
- Mathew J. Morey rebuts MISO's cost-benefit analysis by showing that MISO's gross errors in its PROMOD IV modeling render MISO's cost-benefit analysis singularly inappropriate for drawing any useful conclusions.
- Dr. Susan F. Tierney will rebut certain regulatory contentions of Dr. McNamara concerning the purported regulatory benefits of MISO membership for the Kentucky Commission.
- Michael S. Beer will rebut the rate and regulatory contentions of Dr. McNamara that the Energy Markets Tariff "will not cause the Kentucky PSC to lose regulatory control over any aspect of retail rates or retail service."

Q. What are the most significant points MISO has made that the Companies wish to rebut?

A. There are three. First, as Messrs. Morey and Sinclair show with clarity in their rebuttal testimonies, MISO's claim that the Companies will enjoy any net benefit at all through continued MISO membership is entirely without foundation because MISO's cost-benefit analysis contains the gross and fatal error of including in the Companies' generation dispatch units those controlled by Western Kentucky Energy ("WKE"), but not included within the MISO footprint, while excluding long-standing generation supplied to the Companies by the OVEC and EE Inc units. As Mr. Morey concludes, MISO's erroneous inclusion of the WKE units renders the MISO cost-benefit analysis "unusable."

Even if MISO's study is corrected for MISO's error -- to the extent that is possible -- MISO's claim that the Companies will enjoy well over $300 million in total net benefits during the years 2005-2010 as compared to exiting MISO deflates to a projection that the Companies will receive only about $5 million in net benefits per year.[1] Given that MISO has already demonstrated that it grossly erred in the assumptions it used in its modeling, even the $5 million per year figure is highly suspect, and ought to be given no weight as compared to the Companies' more reliable cost-benefit study, which shows that the Companies will endure significant net <u>costs</u> over the study period if they continue as MISO members. And none of these figures account for the unquantifiable risks of the Companies' continued participation in MISO that neither the Companies nor MISO were able to include in their models.

[1] This figure is based on the reasonable assumption that there is a 95% payout from MISO on the face value of FTRs that the Companies hold. As Mr. Morey argued in his supplemental direct testimony, this assumption is reasonable, if not generous to MISO, based on actual FTR payouts in PJM.

Second, the Companies disagree with MISO's assertion that the Companies will enjoy net economic benefits as MISO members in Day 2 as compared to exiting MISO. MISO's administrative costs are certain and quantifiable; although MISO believes there are offsetting revenues, these are speculative at best. Moreover, there are other risks of continuing MISO membership that the Companies simply could not quantify, which might dwarf any potential offsetting benefits of MISO membership. The rebuttal testimony of Dr. McNamara and the rebuttal testimony of Mr. Morey, together, conclusively demonstrate that the Companies will incur additional costs from their membership in MISO in the range of $16.7 million to $17.8 million per year. What is far less certain is whether the Companies will incur sufficient additional revenues to cover these costs. Dr. McNamara's cost-benefit study predictably shows that the Companies are estimated to receive approximately $43.9 million per year in recurring net revenues or other economic benefits from their membership in MISO and participation in its real-time and day-ahead energy markets under its EMT tariff. Mr. Morey's analysis, however, continues to show that a reasonable estimate of the Companies' total net recurring cost of continuing as MISO members is between $6.5 million and $31.3 million per year, depending upon the assumptions used.[2] This represents a net loss to the Companies. The Companies' evidence demonstrates that MISO's purported revenues are highly speculative and cannot reasonably be anticipated to offset more than a portion of the Companies' MISO membership costs.

Third, the Companies disagree with MISO's assertions that the various alternatives to the Companies' continued MISO membership all degrade the level of reliability the Companies would experience if the Companies remain in MISO. The

[2] See Morey Supplemental Direct Testimony at 7 (Table 2).

rebuttal testimonies of Mr. Johnson and Mr. Gallus respectively address the transmission and generation reliability impacts of MISO membership versus non-MISO membership. Mr. Johnson's testimony makes clear that transmission reliability does not depend upon wholesale market economies, as Dr. McNamara asserts.

Q. Have the Companies given further consideration to their request to withdraw from MISO based on the testimony of Dr. McNamara?

A. Yes. However, further analysis by the Companies and Mr. Morey of the information provided in Dr. McNamara's rebuttal testimony continues to show that withdrawal from MISO would be in the best interest of our customers and the Commonwealth of Kentucky because the costs outweigh the benefits. For these reasons, on December 28, 2004, the Companies formally notified MISO of their intent to withdraw from the MISO. A copy of that written notice is attached to my testimony as PWT Rebuttal Exhibit-1. This will allow LG&E and KU to depart, subject to the approval of the Federal Energy Regulatory Commission and this Commission, at the earliest possible date, December 31, 2005.

Q. Is there any indication in Dr. McNamara's rebuttal testimony that MISO members can reasonably expect the costs of membership to significantly decrease in the future?

A. While MISO continues to assert, through its witness Dr. McNamara, that the revenues associated with the Companies' MISO membership will exceed the costs, as discussed above, the Companies' analyses clearly show that MISO's EMT will continue to increase the costs that the Companies will have to bear.

For example, through December 31, 2004, MISO estimates that it has incurred $176,297,000 in market start-up and market design issue costs. These costs are being deferred as regulatory assets for collection from MISO members once the EMT markets become operational. The concern over ever increasing costs caused many MISO members, certainly LG&E and KU, at a meeting in Carmel, Indiana on December 9, 2004, to vote against the Nomination Committee's endorsement of two incumbent board members, Mr. DeRosa and Mr. Albertini, and a third nominee. Both incumbents failed to receive the requisite majority. This is the first time a slate of candidates proposed by the Nomination Committee has been rejected by the members. The rejection reflects the increasing concern of MISO members with MISO's management of issues such as management transparency, the MISO budgeting process and RTO mission and scope.

Q. Do you agree with Dr. McNamara's assertion at page 7, lines 15-24 of his testimony that the Companies could not achieve the same reliability and regional coordination benefits as TORC[3] entities with reliability authority functions performed by another entity such as SPP or TVA?

A. No. As discussed in the rebuttal testimony of Mark S. Johnson, reliability is not dependent upon market efficiency or increased liquidity in the market.

Q. Do you agree with Dr. McNamara's assertion that the Companies in effect will be "free riders" once they withdraw from MISO when they transact in the MISO footprint?

A. No. His contention is without merit for two reasons. First, it ignores the undisputed fact that the Companies' participation in the Day 2 spot energy markets and FTR markets as TORC entities would be subject to the imposition of Schedule 16 (FTR administration) and 17 (market administration) fees. Thus, the Companies would be no different than any

[3] "TORC" is an abbreviation for "Transmission Operator with Reliability Coordination."

other non-MISO members, such as Big Rivers Electric Cooperative ("BREC") and East Kentucky Power Cooperative ("EKPC"), who transact in the MISO footprint.

Second, should the Companies receive Commission and Federal Energy Regulatory Commission ("FERC") authority to exit MISO, they will pay MISO an exit fee to cover their share of MISO's capital obligations to date. It is important to remember that the exit fee is, and was, intended to prevent capital costs from being inequitably shifted onto, or away from, a departing member. Therefore, unlike other non-MISO-member entities that transact in the Day 2 markets, the Companies, under any of the out-of-MISO options, will already have paid an exit fee designed to allow MISO to recoup the Companies' proportionate share of RTO development capital costs, making MISO's proposed access fee akin to double taxation of the Companies.

In other words, far from being free riders, should the Companies choose to transact in the MISO footprint as TORC entities, the Companies will have paid <u>more</u> than any other entities to do so, excepting any other entities transacting with MISO's Day 2 markets that are also <u>former</u> MISO members.

Q. Do you agree with Dr. McNamara that the best course of action for the Companies to pursue is continued MISO membership?

A. Absolutely not. As shown in this and the other Companies' witnesses' testimony, the Commission should determine that the Companies' continuing membership in MISO is no longer in the public interest of Kentucky customers and should authorize the transfer of the functional control over the Companies' transmission system from MISO to LG&E and KU, subject to FERC approval and conditioned upon the Companies entering into an adequate security coordination agreement with a third party.

Q. Does this conclude your testimony?

A. Yes, it does.

Paul W. Thompson
Senior Vice President
Energy Services

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VIA OVERNIGHT MAIL, FACSIMILE, AND ELECTRONIC MAIL
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December 28, 2004

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

Dear Jim:

Pursuant to and in accordance with Section 1 of Article Five and Section J of Article Nine of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("MISO"), a Delaware Non-Stock Corporation ("TO Agreement"), Louisville Gas and Electric Company and Kentucky Utilities Company (hereinafter, the "Companies"), each hereby tenders to you in your capacity as President of MISO notice of withdrawal to effectuate withdrawal of the Companies' facilities from the Transmission System (as defined under Article One of the TO Agreement). The Companies note that Section 1 of Article Five of the TO Agreement provides that, based on the delivery date of this notice of withdrawal, the Companies' withdrawal will not become effective at any time prior to December 31, 2005, and that such withdrawal requires the approval of the Federal Energy Regulatory Commission. Such withdrawal, when effective, shall terminate the Companies' status as an Owner pursuant to the TO Agreement.

The Companies look forward to working with you closely to coordinate any transition issues that may arise. We are also certain that MISO and LG&E personnel will continue to coordinate their efforts to ensure that the system is operated in a reliable and efficient manner.

Please do not hesitate to contact me if you have any further questions.

Sincerely,

VERIFICATION

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

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

Paul W. Thompson
PAUL W. THOMPSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of January 2005.

Tammy J. Elzy
Notary Public

My Commission Expires:

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

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

Filed: January 10, 2005

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

A. My name is Martyn Gallus. I am the Senior Vice President of Energy Marketing for LG&E Energy LLC ("LG&E Energy"), the parent company of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU" or "the Companies"). My business address is 220 West Main Street, P.O. Box 32030, Louisville, Kentucky 40202.

Q. Have you previously testified in this proceeding?

A. Yes. I previously testified in this investigation at the hearing on February 25, 2004. I submitted supplemental direct testimony on September 29, 2004 in the second phase of the Commission's investigation.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut Dr. McNamara's contentions that MISO's use of centralized Security Constrained Economic Dispatch ("SCED"), Locational Marginal Prices ("LMPs"), and Financial Transmission Rights ("FTRs") will have a favorable impact on the Companies' marketing operations, dispatch, and overall business.

Q. At page 5 of his rebuttal testimony, Dr. McNamara states that "there are numerous misconceptions in the LG&E/KU testimony that can be boiled down to a few misunderstandings of how the EMT works..." Does the filed stipulation entered into by LG&E/KU and MISO address these alleged "misunderstandings?" How should the Commission view and make use of the stipulation?

A. LG&E/KU do not agree with Dr. McNamara's claims that numerous misconceptions or misunderstandings with respect to the EMT exist in the

Companies' testimony. At the Companies' request, a meeting was held between the Companies and MISO on December 2, 2004, for the sole purpose of clarifying any misunderstanding of how the EMT works. The result of this meeting is a stipulation between LG&E/KU and MISO (the "Stipulation") filed in the record of this proceeding on December 7, 2004. The only new information of significance to the Companies was a clearer understanding of the role of the Independent Market Monitor ("IMM") in Day-Ahead energy markets. The basic claims of the Companies in this proceeding remain unchanged following the Stipulation. The basic issue is not a difference between the Companies and MISO with respect to what the tariff says, but rather a difference of opinion as to what it will mean operationally and financially to the Companies.

The Companies and MISO entered into the Stipulation in order to identify those issues relating to how the EMT works that are not in dispute. The Stipulation is intended to provide a foundation upon which the Commission can make the most efficient use of its time and resources during this investigation and bring the matter to an informed conclusion. The Stipulation recites operational mechanics of certain aspects of the EMT and is not meant to express or imply any position on the EMT as a matter of policy.

Q. Dr. McNamara states at pages 5-6 of his rebuttal testimony that the Companies retain "all the control they need to ensure that its own low-cost resources are available to serve LG&E/KU and Kentucky customer loads." Do you agree?

A. No. In a very simplified view, the Companies employ a two step process in serving native load customers. First, the Companies undertake to ensure that they have on hand at all times generation capacity sufficient to meet native load energy and operating reserve requirements. This process is continuous up until and including real-time. Second, once the Companies are reasonably certain that capacity sufficient to meet native load energy and operating reserve capacity is in place, the Companies proceed to optimize the value of this capacity for the benefit of native ratepayers through energy market purchases and sales.

The MISO Day-Ahead Energy Market and Reliability Assessment Commitment, ("RAC"), must offer requirements directly impact the Companies' ability to perform the process I just described. Specifically, as stated in the Stipulation,[1] the Companies must submit a unit commitment status for all Designated Network Resources ("DNRs") indicating that the Generation Resource identified as a DNR is either:

1. a Must Run unit;
2. an Economic unit;
3. an Emergency unit; or
4. unavailable.

Further, DNRs not receiving a Day Ahead Market commitment schedule at the close of the Day-Ahead Energy Market must provide a unit schedule or offer into the MISO's RAC.[2] These mandatory requirements in the Day-Ahead Energy market and RAC degrade the Companies' control over their own resources necessary to fulfill their obligation to serve their native load. Today, with the exception of Automatic Reserve Sharing ("ARS"), the Companies are not

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[1] Stipulation ¶ 3.
[2] Id. ¶ 4.

required to commit their resources for the benefit of regional (non-native) load. While the EMT provides the Companies the flexibility to reflect, in the price offered, the risks associated with resource availability and load fluctuations, this flexibility is limited in the Day-Ahead energy market by the $1,000 per MWh offer cap per EMT §39.2.5 f and is subject to the MISO's market monitoring and mitigation procedures contained in Module D of the MISO EMT. While these constraints appear on the surface to be relatively benign, the full impact of such restrictions may be significant during periods of high load and/or reduced generation availability.

Q. **Are there other aspects of the EMT and/or MISO Day 2 operating procedures which Dr. McNamara has neglected in determining that the companies retain "all the control they need to ensure that its own low-cost resources are available to serve LG&E/KU and Kentucky customer loads" (Dr. McNamara rebuttal testimony at pages 5-6)?**

A. Yes. In order to ensure that LG&E/KU customers will be served, LG&E/KU must retain the ability to commit capacity for the benefit of LG&E/KU customers at all times. As we know from MISO's response to LG&E/KU's data request on the topic, MISO has no obligation to serve LG&E/KU load and thus that obligation remains with LG&E/KU. It would seem axiomatic that one who has a particular obligation should also have the ability to fulfill that obligation. Today, LG&E/KU have the authority to support their obligation to serve; in Day 2, LG&E/KU will continue to have the obligation to serve but do not have the requisite authority to fulfill that obligation.

Regardless of whether the Companies elect to participate in whole or in part in the MISO Security Constrained Unit Commitment ("SCUC") and RAC commitment processes, the Companies will be subject to MISO load-shedding directives should an emergency situation progress to the NERC Energy Emergency Alert ("EEA") 3 level . Despite having adequate resources on-line to meet LG&E/KU native load, the Companies will not be able to ensure that its own low-cost resources are available to serve LG&E/KU loads.

The Stipulation includes an acknowledgement that this load-shedding directive may occur when energy emergencies arise on an unconstrained transmission system.[3] This is a true statement with which LG&E/KU agree, however, a review of the requisite filed EEA 3 reports shows that these events always occur within a sub-region defined by transmission constraints.[4] LG&E/KU submit that in Day 2, any time such a sub-region encompasses LG&E/KU and at least one other control area, LG&E/KU will be included in the definition of an energy deficient area regardless of how much LG&E/KU-owned capacity happens to be on-line producing energy. If a load-shedding directive is then issued to LG&E/KU, their retail customers will lose service in circumstances that would not result in a loss of service for those customers today.

Q. With reference to Dr. McNamara's assertion that the Companies will retain "all the control they need to ensure that its own low-cost resources are available to serve LG&E/KU and Kentucky customer loads," how does the role of MISO's Independent Market Monitor ("IMM") impact the

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[3] Stipulation ¶ 22.

[4] NERC policies require the energy deficient area to file an EEA 3 report after each EEA 3 event. These reports for the past five years can be found at http://www.nerc.com/~filez/alertlogs.html.

Companies' ability to price into their units' offers amounts to compensate for the risks faced by the Companies in serving native load caused by loss of control over such units resulting from the EMT's must-offer requirement?

A. As discussed at length above, MISO's EMT contains a must-offer requirement that obligates the Companies to offer their generation into MISO's day-ahead and real-time markets, which will deprive the Companies of significant control to dispatch their units needed to ensure that their native load customers are served. Instead, in Day 2 the Companies will have to purchase energy from the MISO markets to ensure their native load customers are served. This MISO-imposed inability for the Companies to dispatch their units in real-time to meet the needs of native load creates a real risk of additional cost to serve native load that the Companies would not have incurred had they been able to serve native load with their own units. This new risk is real and could have significant economic impacts.

One way that the Companies could attempt to soften the economic blow that this additional risk creates would be to price that additional risk into the offer curves they submit to MISO for the units they must offer into the markets. The IMM's monitoring and mitigation plans, however, threaten this legitimate business strategy. In Module D of the EMT, the IMM has proposed automatically to mitigate offer prices in the Day Ahead market that exceed certain conduct and impact thresholds. Additionally, to streamline the process, the IMM has suggested it would mitigate all bids that fail the conduct test, without regard to the market impact, but admitted that this would result in over-mitigation. Nevertheless, there remains the possibility that the IMM could mitigate the

Companies' market offers -- even those well below the $1,000 offer cap -- effectively preventing the Companies from being able to price their units at their real costs, which include the risk discussed above.

Although in its November 8, 2004, Rehearing Order concerning the EMT, the Federal Energy Regulatory Commission ("FERC") allowed the IMM to delay the implementation of automatic mitigation procedures ("AMP") for Day-Ahead prices, it did so only because the IMM indicated that such mitigation procedures are not needed at the beginning of Day 2 operation and due to the fact that the IMM lacked the software to implement the AMP (existing software is inadequate given the vast size of the Midwest ISO compared to other regions using AMP), and the lack of time to run the mitigation procedures in the Midwest ISO's start-up market design. However, FERC is requiring the IMM to report on Day-Ahead pricing for possible implementation of automatic price mitigation at a later date.

Q. **Again with reference to Dr. McNamara's assertion that the Companies will retain "all the control they need to ensure that its own low-cost resources are available to serve LG&E/KU and Kentucky customer loads," are there any other aspects of the MISO EMT that degrade the amount of control LG&E/KU will have in Day 2 to serve LG&E/KU load?**

A. Yes. In approving the EMT, the FERC found it appropriate for the IMM to monitor for anti-competitive behavior at the control area level.[5] However, because the control area operators' responsibilities varied across the Midwest

[5] See Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,163 (2004) ("Order Conditionally Accepting Tariff Sheets to Start Energy Markets and Establishing Settlement Judge Procedures").

ISO, the Commission directed the IMM to develop and implement a plan for monitoring the actions of control area operators.[6] The Midwest ISO added a new section, 53.1.g, to the market monitoring section of the EMT dealing with monitoring of control area operators which provided that the actions to be monitored would include, but not be limited to:

1. Unnecessarily withholding capacity from the Energy Markets by arranging for more spinning, non-spinning and Operating Reserves than is justifiably needed for reliability purposes.
2. Causing more units to be committed through the RAC process or other supplemental commitment processes than needed for reliability purposes.
3. Failing to maintain reasonable levels of Area Control Error ("ACE").
4. Redispatching Generation Resources in a manner that is not necessary or is inefficient to resolve local constraints or satisfy local reliability requirements . . ..

These provisions establish the IMM as the ultimate arbiter of determining what is reliable system operation. LG&E/KU operate today in accordance with all applicable NERC, ECAR and state rules, regulations, procedures and policies. The Companies should not have to anticipate how the IMM's economic impact analysis might interpret actions designed to maintain system reliability and ensure load is served, particularly when there are already in place far more experienced and qualified entities responsible for these matters.

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[6] Id.

In response to protests by LG&E/KU and other parties, the FERC, in its December 20, 2004 Order, clarified that control area operators will not be subject to enforcement action by FERC when the control area is following the directions of NERC, MISO (under the Balancing Area agreement), local reliability councils or individual states.[7] The standards for monitoring control areas, however, are still unclear. In the December 20, 2004, Order, FERC rejected the standards laid out in the EMT for monitoring control areas on the basis that the proposed standards are not in the tariff, and the standards that were proposed in testimony filed with FERC are still not sufficiently objective.[8] FERC required the control area standards, including the vague ones, to be revised and clarified.[9] As a result of this ongoing process, much uncertainty remains as to what the IMM's role will be in monitoring control areas.

Q. With reference to page 7 of Dr. McNamara's rebuttal testimony, do the Companies agree that the benefits of regional economic dispatch merit the Companies' continuing MISO membership?

A. No. As Mr. Morey's testimony demonstrates, the costs of MISO membership, including all the costs attributable to MISO's SCED itself, outweigh any lower purchase-power costs and higher off-system sales volumes that the SCED might create. Moreover, MISO's assertion, like its other assertions concerning economic matters, is of dubious merit, given MISO's serious errors in the PROMOD IV modeling that underlies MISO's cost-benefit analysis. As Mr. Sinclair's and Mr. Morey's testimonies show, correcting for MISO's modeling

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[7] See Midwest Independent Transmission System Operator, Inc., 109 FERC ¶ 61,285 (2004) ("Order on Compliance Filing").
[8] Id.
[9] Id.

errors reduces the net benefit that MISO's cost-benefit analysis produces from well over $300 million over the course of the study period to, at most, $30 million in nominal dollars over the same period. Given the solid evidence of the Companies' cost-benefit analysis, which shows that the Companies will experience a net recurring cost totaling between $39 million and $80 million over the same period, and the fact that neither Companies nor MISO has undertaken to quantify several potentially economically consequential risks of MISO membership, the benefits of regional dispatch alone do not merit the Companies' continuing MISO membership.

Q. Again with reference to page 7 of Dr. McNamara's rebuttal testimony, do the Companies agree that the increased the scale and scope of MISO's regional economic dispatch will benefit the Companies, much as the joint dispatch between LG&E and KU has created economic benefits?

A. No, because the situations are not analogous, as Dr. McNamara erroneously implies. The Companies do not contest that SCED might create regional dispatch efficiencies that today's decentralized dispatches do not. But it is not enough simply to make such a statement and ignore both the associated costs of implementing and administering a given centralized dispatch and the extent to which the regional efficiencies redound to the benefit of LG&E/KU. In the case of LG&E and KU's joint dispatch, the benefits associated with enhanced dispatch efficiencies and other synergies in the LG&E and KU merger were significantly less than the costs to achieve those benefits; hence, it was a wise economic decision to implement the Companies' joint dispatch and other merger efficiencies. The same cannot be said for MISO's SCED, as the Companies' cost-benefit analysis shows. Increasing the scale and scope of a centralized dispatch is not an economic benefit to the Companies per se; it only makes economic sense if the benefits to the Companies of the larger-scaled dispatch outweigh the costs of achieving them. In the case of MISO's SCED, they do not.

In short, the fact that the scale and scope of MISO's SCED might create certain regional efficiencies and savings is irrelevant unless the benefits of achieving those efficiencies and savings exceed the costs to achieve them; only net economic benefits and costs to the Companies are relevant to the Companies' decision-making and the Commission's decision in this investigation.

Q. With reference to page 7 of Dr. McNamara's rebuttal testimony and your response to the question above, are there incremental costs associated with the changes in how LG&E/KU must utilize their resources to meet load under the EMT?

A. Yes. Cost implications of the MISO commitment processes arise from MISO's allocation of the Day-Ahead unit commitment and RAC unit commitment revenue sufficiency guaranties. In each case, Day-Ahead and RAC, LG&E/KU will bear a share of the cost of ensuring that generators that MISO commits recover their startup and standby (no load) costs.[10] This cost impact will be applicable even if LG&E/KU self commit LG&E/KU generation, thus incurring their own commitment costs.[11] Specific to the RAC cost allocation, deviations from Day-Ahead schedules are included in the RAC revenue sufficiency guaranty billing determinants.[12] Thus, RAC imposes a cost on the Companies' retention of the up

[10] Stipulation ¶¶ 17 & 23.
[11] Id.
[12] Id. at 16.

to real-time scheduling and commitment flexibility the Companies need to ensure LG&E/KU loads are reliably served.

With respect to other costs, all scheduled generation and load, whether self-scheduled in the Day-Ahead or Real-time or otherwise, is subject to MISO settlement.[13] This settlement includes congestion and losses which together comprise the MISO transmission usage charge.[14] Finally, despite the Companies' best efforts to self provide energy and capacity, in real-time the Companies will likely remain exposed to some amount of energy imbalance and unhedged congestion costs. I will discuss this exposure in more detail later in my testimony.

Q. Dr. McNamara states at page 41 of his rebuttal testimony that "the use of LMP and FTRs will neither increase congestion nor increase the costs and risks of managing congestion." Do you agree?

A. The use of LMP and FTRs may have benefits for the region as a whole; however, the more important question in this proceeding is whether there are benefits for the Companies and their customers. I contend that the use of LMP and FTRs to manage congestion will impose significant costs and increased risk on the Companies and their customers.

Today, the Companies realize the costs of congestion through the redispatch of higher cost units to relieve congestion. Those costs have been monitored since 1999 and range from $267,000 to $1.6 million per year. MISO's own forecast (as corrected by Mr. Morey) of the Companies' congestion costs associated with serving native load is $37.5 million per year, although there is still

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[13] See generally Stipulation.
[14] Id. ¶¶ 15 & 21.

great uncertainty about the accuracy of this estimate because of the errors committed by MISO in conducting its cost-benefit study, as discussed in detail by Mr. Sinclair and Mr. Morey in their rebuttal testimonies. This corrected estimate clearly confirms the risk that the Companies will experience an increase in the cost of congestion.

Q. **At page 44 of his rebuttal testimony, Dr. McNamara indicates that based on his analysis the Companies should be able to acquire more than enough FTRs to hedge fully their exposure to congestion costs and thus receive a net benefit from FTRs over congestion costs. Do you agree with this position?**

A. No. It would be highly speculative for the Companies to pursue a portfolio of FTRs with the expectation of a net gain. The Companies view FTRs as a tool for hedging the expected congestion costs associated with serving native load. To acquire more FTRs than are needed for this purpose is, in effect, speculating on the future value of the FTRs. The Companies seek to manage risks that are inherent in serving their native load customers, not introduce new risks that may potentially result in unnecessary costs. The future value of specific FTRs is highly uncertain and dependent upon many factors, including the behaviors of market participants in the new Day 2 markets. Therefore, the Companies' goal in the FTR allocation process is to acquire the FTRs that provide an offset, or hedge, against the uncertain congestion costs the Companies are expected to experience.

Q. **With reference to pages 43-45 of Dr. McNamara's rebuttal testimony, will FTRs provide an offsetting revenue such that the Companies' net congestion costs (congestion expense less FTR revenue) will be similar to that which the Companies have experienced historically?**

A. The effectiveness of FTRs as a hedge of the Companies' congestion costs is highly uncertain. The Companies cannot be certain at this time whether they will receive the desired portfolio of FTRs. MISO has completed two tiers of the four-tier FTR allocation process. Additionally, MISO has completed the assignment of counterflow FTRs and associated restoration FTRs. This process has provided the Companies with some indication of the FTRs which will ultimately comprise the Companies' FTR portfolio. The table below summarizes the allocation process to date for the Companies.

Percent of LG&E/KU Nominated FTRs Allocated by MISO

Allocation Phase	Spring On-Peak	Spring Off-Peak	Summer On-Peak	Summer Off-Peak
Tier 1	99.9%	99.9%	88.0%	98.4%
Tier 2	53.2%	100%	23.9%	23.3%
Restoration	99.0%	NA	49.4%	60.1%
Cumulative Result	97.3%	100%	83.2%	88.9%

As can be seen in the table, significantly less than 100% of the FTRs nominated by the Companies for the summer period have been allocated by MISO. While the allocation process is not complete, the results to date indicate that the Companies are not likely to receive the portfolio of FTRs necessary to provide an effective hedge against the congestion costs associated with serving native load customers. Attached as MG Rebuttal Exhibit 1 is an interim informational report MISO filed with FERC describing the process and results of the FTR allocation process for the first two tiers and a subsequent FTR "restoration" process through the assignment of counterflow FTRs.

Q. If the Companies receive 100% of the FTRs nominated in the FTR allocation, will the Companies then be in a position to limit the net congestion costs to the levels experienced historically?

A. No. Even in the event the Companies are able to assemble the desired portfolio of FTRs, the effectiveness of these FTRs as a hedge against the congestion costs the Companies will experience is highly uncertain. In supplying their native load customers from their own generating resources, the Companies will incur congestion costs as a result of the difference between the congestion component of LMP at the generating resource and the congestion component of LMP at the load zone. The actual hourly generation and load volume will be the other key determinants of the total congestion cost associated with serving load. FTRs, however, are allocated in seasonal tranches by peak-type (e.g. Spring-On Peak, Spring Off Peak), resulting in a fixed and constant volume of FTRs in each tranche. Given the traditional hourly load shape and weather related variability in demand, the volume of FTRs for a given hour is unlikely to match the actual load for that hour. Further, the FTRs are allocated from specific generating units (LG&E/KU have approximately 43) to specific load zones (LG&E/KU have 2). Unfortunately, the specific units do not supply fixed and constant volumes to each of the load zones.

Q. Dr. McNamara contends at page 43 of his rebuttal testimony that the Companies will not necessarily face higher exposure to unhedged costs if they do not get the FTRs they ask for. Do you agree?

A. No. The Companies have requested FTRs that are expected to counterbalance the uncertain congestion costs the Companies will face in serving native load customers. To the extent the Companies do not receive these FTRs, they are by definition unhedged and face a higher net exposure to congestion costs. Dr. McNamara misleads by stating that a non-matching set of FTRs could provide an effective hedge. The cash flows from a non-matching set of FTRs may happen to offset the congestion cost, but this would likely be only a coincidence. The price determinants of the non-matching FTRs are simply different than the price determinants of the Companies' congestion costs.

Q. At pages 34-36 of his rebuttal testimony, Dr. McNamara suggests that the Companies cannot under the TORC option achieve the trading opportunities available to LG&E/KU as MISO members. Do the Companies agree?

A. No. Dr. McNamara provided no empirical data to the Companies' data request on this matter.[15] Under the TORC option, the Companies could and would continue to trade bilaterally with traditional counterparties located outside the MISO footprint. In addition, the Companies would have the opportunity to export into MISO either bilaterally with specific MISO members or as a MISO market participant transacting at the external proxy bus. Similarly, on those rare occasions when there are lower cost resources available with which to serve LG&E/KU native load, LG&E/KU would identify these opportunities by monitoring the external proxy bus or, as today, by soliciting prices from prospective counterparties.

All parties recognize the fact that MISO Day 2 is one particular market design of multiple potential market designs. There is in place today an active

[15] See Response of the Midwest Independent Transmission System Operator, Inc. to the LG&E/KU 12/07/04 Supplemental Data Requests, Item No. 51.

bilateral market with a generally high level of energy price discovery. Today's bilateral market is efficient; to the extent that Day 2 may add efficiencies to the bilateral market, those efficiencies will not be appreciably impacted by the Companies' membership in or exit from MISO. So if we assume MISO Day 2 adds efficiency overall to the wholesale marketplace, and we assume further that that efficiency gain is a primary objective of Kentucky regulation (each a questionable assumption in isolation), then I would respectfully suggest that the question before the Commission is whether any further efficiencies LG&E/KU's membership in MISO might bring to wholesale markets is worth the cost of LG&E/KU's membership. LG&E/KU will in any event be actively involved in whatever wholesale energy market arises in the Midwest.

Q. Does this conclude your testimony?

A. Yes, it does.

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MISO MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

January 5, 2005

Via Hand Delivery

Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20246

Re: Informational Filing of Midwest Independent Transmission System Operator, Inc. on FTR Allocations, FERC Docket Nos. EL04-104-___ and ER04-691-___

Dear Secretary Salas:

The Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") hereby submits an original and fourteen copies of the enclosed interim informational report describing the process and results of the first two tiers of the Midwest ISO's Financial Transmission Rights ("FTRs")[1] allocation process. As detailed in this filing, the FTR allocation process has been successful in allocating approximately 98 percent of all eligible FTRs that have been nominated by Market Participants to date.

I. Background

On March 31, 2004, the Midwest ISO filed the EMT in this proceeding ("March 31 filing") based on input it received from stakeholders and guidance provided by the Commission.[2] The essential elements of the EMT submitted with the March 31 filing included the following: (1) regional, bid-based security-constrained economic dispatch based on Locational Marginal Pricing ("LMP"); (2) Day-Ahead and Real-Time Energy Markets (collectively, the "Energy Market"); (3) allocation of Financial Transmission Rights ("FTRs") and administration of supplemental FTR auctions; (4) an appropriate market monitoring and mitigation program; and (5) interim resource adequacy requirements. On May 26, 2004, the Commission issued an order

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1 Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the EMT.

2 *Midwest Independent Transmission System Operator, Inc.*, 105 FERC ¶ 61,145 (2003) ("Guidance Order"), *reh'g denied*, 105 FERC ¶ 61,272 (2003).

which, among other things, directed the Midwest ISO to file the results of its initial allocation of FTRs at least 90 days prior to the start of the EMT's Energy Markets on March 1, 2005.[3]

On September 15, 2004, the Commission issued an order that concluded its investigation into how grandfathered transmission agreements ("GFAs") should be treated in the Midwest ISO's new energy markets.[4] The GFA Order also discussed how GFAs should be treated for purposes of the allocation of FTRs to Market Participants operating under GFAs. As a result of the need for the Midwest ISO to evaluate and respond to the FTR related directives of the GFA order, the Midwest ISO informed the Commission in its October 5, 2004, compliance filing in this proceeding that it would not be able to complete and file with the Commission the results of FTR allocations until at least January 31, 2005.[5] As a result, the Commission granted the Midwest ISO leave to make the required compliance filing of FTR results on or near the expected completion date of FTR allocations.[6]

The Midwest ISO will file complete results of the entire FTR allocation process with the Commission on or about January 31, 2005. However, in order to provide the Commission and Market Participants with an update on how the FTR allocation process is progressing, this interim informational filing describes the results achieved so far in the FTR allocation process. The FTR allocation process is taking place through a series of four tiers in which a set percentage of eligible FTRs are nominated by each market participant in each tier[7] and then granted by the Midwest ISO according to the results of a simultaneous feasibility test ("SFT") that determines the ability to actually accommodate the FTRs nominated. In addition, at the end of the second tier of nominations and allocations, the Midwest ISO completed a "restoration process" which restored some FTRs that were not allocated in Tiers I and II.[8] During this restoration process, the Midwest ISO attempted to restore FTRs that were not granted in Tiers I and II by defining Counter Flow FTRs sufficient to make nominated (but not granted) FTRs simultaneously feasible.

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3 *Midwest Independent Transmissions System Operator, Inc., et al.,* 107 FERC ¶ 61,191 at P 95 (2004) (the "May 26 Order").

4 *Midwest Independent Transmission System Operator, Inc.,* 108 FERC ¶ 61,236 (2004) (the "GFA Order").

5 *See Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,285 at P 53 (2004).

6 *Id.* at P 88.

7 In each tier of the FTR allocation process, market participants are allowed to nominate a specific percentage of its maximum nomination eligibility less the FTRs awarded to it in the prior tier. The cumulative amount of eligible FTRs that may be nominated in each allocation tier are as follows: Tier I, 35 percent; Tier II, 50 percent; Tier III, 75 percent; and in Tier IV, 100 percent.

8 To be eligible for restoration, nominated (but not granted) FTRs must be from a network resource with an average capacity factor of at least 70 percent, or if nominated FTRs represent a conversion of existing point-to-point service, the nominated FTRs must be for service that has a historical scheduling factor of at least 70 percent.

The Midwest ISO has completed Tiers I and II of the FTR allocation and has also completed the process of determining what FTRs can be restored though the assignment of Counter Flow FTRs. Tiers III and IV of the FTR allocation process still need to be completed before the results of the entire FTR allocation process can be known.[9] This interim informational report will describe the process that the Midwest ISO has used to allocate the FTRs that have been assigned thus far and the results that have been obtained through Tiers I and II and the restoration phase of the FTR allocation process.

II. Process Used to Allocate FTRs in Tier I, Tier II and the Subsequent FTR Restoration and the Results of These FTR Allocations

Pursuant to Section 43 of the EMT, the FTR Allocation process consists of three basic steps: registration, nomination and allocation. This three step process was developed as part of a compromise proposal designed to give all Market Participants the opportunity to receive a full allocation of FTRs from resources used to serve base load.[10] The compromise, which was accepted by the Commission, struck a balance between certain stakeholders that sought mandatory FTR allocations based on historical uses of the transmission system and others that sought flexibility in the ability to nominate and be allocated FTRs.[11] As explained by the Commission, the compromise allocation proposal was based on the idea that while nominations for the first two tiers of FTR allocation would be voluntary, to the extent that a voluntary decision not to nominate FTRs from baseload generation resources within these tiers resulted in there not being counterflow available to support the simultaneous feasibility of other Market Participant's FTR nominations, then entities would be required to accept FTRs that were needed to provide the necessary counterflows to make the FTRs that were nominated but not granted in the first two tiers feasible.[12] This entire FTR allocation process is explained in more detail below.

A. Registration

In the first phase of the FTR allocation process, existing transmission entitlements were registered and converted to FTR entitlements. Transmission entitlements eligible for registration included existing OATT service valid for one or more seasons during the allocation period and pre-OATT agreements that elected to be treated as Options A or B GFAs under the EMT. The registration process included defining FTR entitlements in terms of CPNode sources and sinks, MW quantities and terms of service. In addition, Market Participants identified FTR entitlements that meet the definition of an Eligible Base CFTR, as defined under the EMT.

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9 Tier III FTRs are scheduled to be completed January 13, 2005; Tier IV is scheduled to be completed January 28, 2005.

10 *See* August 6 Order at PP 139-141; *Midwest Independent Transmissions System Operator, Inc., et al.*, 109 FERC ¶ 61,157 at P 128 (2004).

11 *Midwest Independent Transmissions System Operator, Inc., et al.*, 109 FERC ¶ 61,157 at P 128 (2004).

12 *Id.*

B. Nomination

FTR entitlements are nominated by Market Participants. The allocation process includes four tiers. In each tier, Market Participants may nominate up to the tier limit, based on a percentage of their total entitlements for both Network Integration Transmission Service and for Point-to-Point Transmission Service. Tier caps are as follows:

- Tier I: 35 percent
- Tier II: 50 percent
- Tier III: 75 percent
- Tier IV: 100 percent.

Tiers are cumulative, meaning that in each tier, Market Participants may nominate to the cap, less amounts allocated in previous tiers. Thus for example, in Tier II Market Participants could have nominated up to 50 percent of their total eligibility, less amounts allocated in Tier I.

In addition, a "Restoration Allocation," was conducted after Tier II. Market Participants with Eligible Base CFTRs that were nominated, but curtailed during Tier II, had the opportunity to request restoration of those curtailed quantities. Such restoration requests were granted to the extent feasible, by adding counter flow provided by Eligible Base CFTRs that had not been previously allocated or requested for restoration.

C. Allocation

After all nominations are received, the Midwest ISO analyzes nominated candidate FTRs ("CFTRs") to determine the amount that can be awarded, given the aggregate of nominations and any physical (*e.g.*, thermal) or operational (*e.g.*, contingency) limits that may arise. To the extent nominated CFTRs exceed the level that can be awarded due to such limitations, CFTRs are curtailed to a feasible level.

D. Process Dates and Results

On November 12, 2004, the Midwest ISO published for stakeholder review and comment, the model assumptions to be used in the upcoming allocation period, including:

- Summer and Spring network models
- Carve out GFAs assumptions
- Contingencies to be included in the model, including contingency selection criteria
- Flowgate constraints to be included in the model
- Loopflow assumptions
- Phase-Angle-Regulator assumptions

The FTR registration period opened on August 9, 2004, and closed on November 19, 2004.

The Tier I nomination period opened on November 22, 2004, and closed on November 30, 2004. Tier I allocations were posted on December 6, 2004 and a conference call was held to discuss results with stakeholders on December 7, 2004. Updated Tier I allocation results were posted on December 12, 2004. Overall, Tier I FTR allocations were 97 percent of nominated values, broken down by period as follows:

- Summer Peak: 95 percent
- Summer Off-Peak: 97 percent
- Spring Peak: 97 percent
- Spring Off-Peak: 98 percent.

The Tier II nomination period opened on December 7, 2004, and closed on December 14, 2004. Tier II allocations were posted on December 20, 2004, and a conference call was held to discuss results with stakeholders on December 21, 2004. Updated Tier II allocations were posted on December 26, 2004. Overall, Tier II FTR allocations were 89 percent of nominated values, broken down by period as follows:

- Summer Peak: 82 percent
- Summer Off-Peak: 85 percent
- Spring Peak: 90 percent
- Spring Off-Peak: 99 percent.

The restoration nomination period opened on December 21, 2004, and closed on December 28, 2004. Market Participants in all cases nominated all eligible CFTRs for restoration. Restoration allocations were posted on January 3, 2005, and a conference call was held to discuss results with stakeholders on January 5, 2005. Overall, FTR allocations for Tiers I, II and the restoration were 98 percent of nominated values, broken down by period as follows:

- Summer Peak: 96 percent
- Summer Off-Peak: 97 percent
- Spring Peak: 99 percent
- Spring Off-Peak: 100 percent.

The complete results of the Tier I, Tier II and Restoration Allocations are included herein in Attachment A to this interim informational filing.

III. Notice and Service

Included herein as Attachment B, and also provided on diskette, is a Notice of Informational Filing suitable for publication in the *Federal Register*. The Midwest ISO hereby respectfully requests waiver of the requirements set forth in 18 C.F.R. § 385.2010 (2003). The Midwest ISO has served a copy of this filing electronically, including attachments, upon all Midwest ISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the Midwest ISO Advisory Committee participants, as well as all state commissions within the region. In addition, the filing has been posted electronically on the Midwest ISO's website at www.midwestiso.org under the heading "Filings to FERC" for other interested parties in this matter.

Good cause exists for granting this waiver due to the volume of interested parties in this matter, the limited resources available to make service and the financial burden to the Midwest ISO in copying and mailing copies of this filing. Many parties, in fact, prefer receiving their copy in electronic format or by the Midwest ISO's website. In addition, the Midwest ISO will provide hard copies to any interested party upon request.

IV. Conclusion

For all of the foregoing reasons, the Midwest ISO respectfully requests that the Commission accept the report filed herein for informational purposes and grant waiver of any Commission regulations that the Commission may deem applicable to this informational filing.

Respectfully submitted,

/s/ *Stephen G. Kozey*

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Attachments

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Patrick Clarey, FERC
Christopher Miller, FERC
Penny Murrell, FERC
Stephen Teichler, Esq.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

MARTYN GALLUS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of January 2005.

Tammy J. Elzy
Notary Public

My Commission Expires:

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

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

Filed: January 10, 2005

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

A. My name is Mark S. Johnson. I hold the position of Director of Transmission for LG&E Energy LLC ("LG&E Energy"), the parent company of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU" or "Companies"). My business address is 119 N. Third Street, P.O. Box 32020, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

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

Q. Have you previously testified before this Commission?

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut Dr. McNamara's claim that the Companies' reliability will suffer if they exit MISO.

Q. Do you agree with Dr. McNamara's assertion on page 2, lines 20-22, that Security Constrained Economic Dispatch ("SCED") is a more efficient way to solve transmission constraints than the current Transmission Load Relief ("TLR") process?

A. No, the efficiency gains Dr. McNamara often refers to in his testimony are not related to reliability, but rather to increased liquidity in the market. To my knowledge, there is no empirical data to support Dr. McNamara's claim that SCED is a more effective way to solve transmission constraints. Dr. McNamara often interchanges operational reliability with economic efficiency. His assertions that SCED provides for a more precise reduction of transactions on a constrained flow-gate than the TLR process arguably are correct because SCED provides for the continuation of transactions through economic dispatch that might be curtailed under a TLR regime. This is clearly market efficiency and not a reliability benefit.

Q. Do you agree with Dr. McNamara's testimony that "there may well be occasions in which LG&E/KU customers will benefit from the ability of MISO to call on other regional resources to solve reliability problems on the LG&E/KU grid?" Is MISO unique in having this ability to call on other regional resources to solve local grid reliability problems?

A. Dr. McNamara is correct that there may be occasions in which LG&E/KU customers would benefit from the ability of MISO to call on other regional resources to solve reliability problems on the LG&E/KU grid; however, MISO is not unique in having the ability to call on other regional resources to solve local grid problems. NERC Policy 9, section E1.6 and the entirety of Section F provide for all NERC approved Reliability Coordinators to have this authority. A copy of these sections of NERC Policy 9 is attached hereto as MSJ Rebuttal Exhibit 1. In addition, this requirement serves as an impetus for the development of Joint Operating agreements between Reliability Coordinators.

Q. Do you agree with Dr. McNamara's testimony that it is "misleading for LG&E/KU witness to compare having some new third party provide this traditional but limited service with the regional dispatch and reliability capabilities that the MISO is offering." What are the limited functions of a reliability coordinator that make it misleading to compare other reliability coordinators with MISO?

A. No, it is not misleading to compare a third party Reliability Coordinator ("RC") with MISO. The functions of all NERC certified Reliability Coordinators are defined by NERC policies. The limited functionality Dr. McNamara is referring to, in my opinion, is related to Day 2 market attributes and not reliability. Again, I believe this is another example of Dr. McNamara conveniently and inappropriately equating operational reliability with economic efficiencies.

Q. Again with reference to Dr. McNamara's assertion on page 2, lines 20-22, that SCED is a more efficient way to solve transmission constraints than the TLR

process, is the TLR process an <u>adequate</u> means for resolving transmission constraints?

A. Yes, purely from a reliability standpoint the TLR process has served the industry well. For an example of how these processes work, it is useful to consider what would occur under both processes if 100 MW needs to be removed from a constrained flow gate. Let's assume SCED can precisely curtail transactions needed (100 MW) and the TLR process for various reasons curtails 150 MW. From a reliability standpoint, the constrained flow gate is relieved by both methods. The primary difference is that the 50 MW of transactions curtailed under the TLR process would have been permitted to continue. Again, this is a market efficiency/liquidity benefit, not a reliability benefit.

Q. Dr. McNamara contends on pages 11 and 12 of his rebuttal testimony that the Companies are employing "outmoded" reliability operations. Are the Companies, in fact, imperiling the reliability of the grid through "outmoded" reliability operations?

A. No, far from it. LG&E/KU completed a very successful NERC readiness audit in May 2004. In fact, our vegetation management procedures were considered industry "best in class" and improvements being implemented in our dual dispatch center operations were cited in our exit interview as moving toward industry "best in class." A copy of this audit is attached hereto as MSJ Rebuttal Exhibit 2.

Additionally, in a letter dated November 1, 2004 to LG&E's CEO, Vic Staffieri, from Jim Torgerson, providing an update on market readiness testing, MISO's own assessment of the Companies' Day 2 control area readiness was that the Companies had successfully completed testing related to reliability readiness. A copy of this letter is attached hereto as MSJ Rebuttal Exhibit 3.

Reliability is the number one priority for the transmission organization. To that end, the company continues to make investments in new technology, tools and training to enhance our operational capabilities.

Q. Dr. McNamara contends at pages 50 through 51 of his rebuttal testimony that no alternative to MISO that the Companies have discussed could provide the Companies same reliability benefits as MISO. Is this true?

A. No. With the proper protocols and procedures for coordination and information sharing in place, reliability coordinators in the region can provide the benefits of MISO's much-touted "regional view" of the region's transmission grid. And, in fact, MISO has heralded its efforts to put such agreements in place. To suggest that one NERC certified RC is superior to another, or that the joint operating agreements ("JOAs") would somehow be insufficient, is a contradiction of MISO's ability to comply with NERC policies as a Reliability Coordinator. Moreover, the tools that Midwest ISO put into place following the blackout were increases in SCADA and other transmission-related equipment not related to Day 2 energy markets, thus, these improvements to transmission monitoring can be performed regardless of whether a company is in MISO or operating transmission outside of the Midwest ISO footprint.

Q. Do the Companies agree with Dr. McNamara's assertion on page 52 of his rebuttal testimony that "[t]here is no apparent logic . . . and no apparent reason to believe that this arrangement [joining SPP] could benefit Kentucky in any way" because SPP is not physically interconnected with the Companies' transmission system?

A. No. To provide reliability coordination services it is not necessary for the Companies' and SPP's transmission systems to be contiguous as long as the necessary real-time operational data can be exchanged between the parties. The Companies would require nothing more than standard kinds of data transfer facilities readily available in the retail market from numerous telecommunications providers (e.g., T1 lines) to obtain the data transfer capacity necessary for SPP to act as the Companies' reliability coordinator. In addition, it would be the responsibility of the RC to implement and execute operating agreements to mitigate reciprocal flow-gate issues.

Q. On page 8 of his rebuttal testimony, Dr. McNamara contends that membership in MISO would improve the Companies' loop flow problems. Do you agree?

A. No. I have seen no evidence produced in this proceeding -- or anywhere else -- to support his claim that loop flows will be improved. The Day 2 market may very well change, or significantly alter, the flow patterns on the system. If, in reality, a shift occurs from historical patterns, different transmission expansion and upgrade plans may be required to address loop flow issues. Also, it will be incumbent upon MISO to implement and execute operating agreements, particularly with entities outside the MISO footprint, to mitigate loop flow conditions.

Q. Dr. McNamara states at page 61 of his rebuttal testimony that SCED should allow MISO to load flowgates up to 100% of their operating security limits ("OSL") on "most, if not all, flowgates." What are some possible short- and long-term consequences of operating the transmission grid under that kind of loading?

A. Assuming that MISO could load "most, if not all, flowgates" at or near 100% of the flowgates' operating security limits because SCED will supposedly allow MISO much finer control over loads on the system, there will be potentially significant detrimental impacts on reliability in the short-term and a more rapid degradation of transmission system elements in the long-term. Understanding the short-term impact is not complicated: the closer you operate any system to its maximum capacity, the less room there is for error. When contingencies occur on the transmission system, the results are felt on the remaining system elements instantly. It is, in my opinion, foolhardy even to suggest loading system elements at or near 100% of their OSL because it compromises the reliability of the system in single- or multiple contingency events, even accounting for MISO's five-minute redispatch under the SCED.

Q. Is it true, as Dr. McNamara asserts on page 11 of his rebuttal testimony, that the transmission grid is much more interconnected and requires more coordination today than in the past?

A. I do not believe that the transmission grid between control areas in the Midwest is vastly more interconnected today than it has been in recent years. The Companies, for example, spend around $20 million annually on transmission expansion and upgrades, but these expansion and upgrade projects are for reliability on the Companies' own system and to connect new customers to the grid, <u>not</u> to enhance the Companies' interconnectivity to other control areas.

As to Dr. McNamara's point concerning coordination, the degree of coordination required to operate the grid reliably depends upon the use of the transmission system. Any mechanism such as Day 2, which in theory strives to increase the economic efficiency of transmission capacity, uses and brings together new buyers and sellers, will require additional coordination from a reliability standpoint. This is particularly true if

MISO really does intend to load flowgates at or near their OSLs because there will be little or no room for error, requiring a significant amount of coordination.

In other words, to the extent that Dr. McNamara implies in his testimony that a supposedly more interconnected grid requires MISO's market to provide the coordination necessary to maintain reliability, he overlooks this fundamental fact: the reliability of the grid does not depend upon the reliability of the market, but the reliability of the market does depend upon the reliability of the grid.

Q. Do you believe that the historical exemplary reliability performance of LG&E/KU can be maintained in the TORC option?

A. I certainly believe that LG&E/KU can and would do everything in its power to ensure our customers continue to enjoy reliable service. We certainly understand and appreciate that as markets evolve a premium will be placed on effective coordination, communication, training and technology. These basic elements are necessary for all parties RTOs, Reliability Coordinators, Transmission Owners and other market participants to ensure reliability.

Q. Does this conclude your testimony?

A. Yes, it does.

MSJ Rebuttal Exhibit 1 – NERC Policy 9

Policy 9 – Reliability Coordinator Procedures

Version 2

Subsections

A. **Responsibilities – Authorization**
B. **Responsibilities – Delegation of Tasks**
C. **Common Tasks for Current-Day and Next-Day Operations**
D. **Next-Day Operations**
E. **Current-Day Operations**
F. **Emergency Operations**
G. **System Restoration**
H. **Coordination Agreements and Data Sharing**
I. **Facility**
J. **Staffing**

Introduction

This document contains the process and procedures that the NERC RELIABILITY COORDINATORS are expected to follow to ensure the operational reliability of the INTERCONNECTIONS. These include:

- Planning for next-day operations, including reliability analyses (such as pre- and post-CONTINGENCY thermal monitoring, system reserves, area reserves, reactive reserves, voltage limits, stability, etc.) and identifying special operating procedures that might be needed,
- Analyzing current day operating conditions, and
- Implementing procedures (local, INTERCONNECTION-wide, or other) to mitigate SYSTEM OPERATING LIMIT (SOL) and INTERCONNECTION RELIABILITY OPERATING LIMIT (IROL) violations on the transmission system. Regardless of the process, the RELIABILITY COORDINATOR shall ensure its CONTROL AREAS return their transmission system to within INTERCONNECTED RELIABILITY OPERATING LIMITS without delay, and no longer than 30 minutes[1]

RELIABILITY COORDINATORS shall have the capability to monitor their responsibilities with a WIDE AREA view perspective and calculate INTERCONNECTED RELIABILITY OPERATING LIMITS. WIDE AREA is described as the ability to monitor the complete RELIABILITY COORDINATOR AREA and may include critical flow and status information from adjacent RELIABILITY COORDINATOR AREAS as determined by detailed system studies. With this in mind it is likely that RELIABILITY COORDINATORS will discover IROL violations not normally seen by its TRANSMISSION OPERATING ENTITIES.

Terms

RELIABILITY COORDINATOR. The entity that is the highest level of authority who is responsible for the reliable operation of the BULK ELECTRIC SYSTEM, has the WIDE AREA view of the BULK ELECTRIC SYSTEM and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real time operations.

OPERATING AUTHORITY. An entity that:

[1] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives — generation/demand balance, transmission reliability, and/or emergency preparedness, and

2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies, and

3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING AUTHORITIES include such entities as CONTROL AREAS, generation operators and TRANSMISSION OPERATING ENTITIES; they do not include RELIABILITY COORDINATORS.

RELIABILITY COORDINATOR AREA. That portion of the Bulk Electric System under the purview of the Reliability Coordinator.

OPERATING AUTHORITY AREA. That portion of the Bulk Electric System under the purview of the Operating Authority that is contained within a Reliability coordinator area.

BURDEN. Operation of the Bulk Electric System that violates or is expected to violate a SOL or IROL in the Interconnection or that violates any other NERC, Regional, or local operating reliability policies or standards.

WIDE AREA. The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

CONTINGENCY. The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components that are related by situations leading to simultaneous component outages.

SYSTEM OPERATING LIMIT (SOL). The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-CONTINGENCY equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-CONTINGENCY Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-CONTINGENCY Voltage Stability)
- System Voltage Limits (Applicable pre- and post-CONTINGENCY Voltage Limits)

INTERCONNECTION RELIABILITY OPERATING LIMIT (IROL). The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the SYSTEM OPERATING LIMITS, which if exceeded, could expose a widespread area of the BULK ELECTRIC SYSTEM to instability, uncontrolled separation(s) or cascading outages.

A. Responsibilities – Authorization

Requirements

1. **RELIABILITY COORDINATOR responsibilities.** The RELIABILITY COORDINATOR is responsible for the reliable operation of its RELIABILITY COORDINATOR AREA within the BULK ELECTRIC SYSTEM in accordance with NERC, Regional and sub-Regional practices.

    1.1. The RELIABILITY COORDINATOR is responsible for having the WIDE AREA view, the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions.

    1.2. The RELIABILITY COORDINATOR shall have clear decision-making authority to act and to direct actions to be taken by other OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA to preserve the integrity and reliability of the BULK ELECTRIC SYSTEM. These actions shall be taken without delay, and no longer than 30 minutes[2]

    1.3. The RELIABILITY COORDINATOR shall not delegate its responsibilities to other OPERATING AUTHORITIES or entities.

2. **Serving the interests of the RELIABILITY COORDINATOR AREA and the INTERCONNECTION.** The RELIABILITY COORDINATOR shall act in the interests of reliability for the overall RELIABILITY COORDINATOR AREA and its INTERCONNECTION before the interests of any other entity (CONTROL AREA, TRANSMISSION OPERATING ENTITY, PURCHASING-SELLING ENTITY, etc.).

3. **Compliance with RELIABILITY COORDINATOR directives.** All OPERATING AUTHORITIES shall comply with RELIABILITY COORDINATOR directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances the OPERATING AUTHORITY must immediately inform the RELIABILITY COORDINATOR of the inability to perform the directive so that the RELIABILITY COORDINATOR may implement alternate remedial actions.

4. **Reliability Plan approval.** The NERC Operating Committee must approve the RELIABILITY COORDINATOR or Regional Reliability Plan.

[2] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

B. Responsibilities – Delegation of Tasks

Requirements

1. **Delegating tasks.** The RELIABILITY COORDINATOR may delegate tasks to other OPERATING AUTHORITIES and entities, but this delegation must be accompanied by formal operating agreements. The RELIABILITY COORDINATOR shall ensure that all delegated tasks are understood, communicated, and addressed by all OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA.

2. **Designating delegation**. The RELIABILITY COORDINATOR or Regional Reliability Plan must list all OPERATING AUTHORITIES and entities to which RELIABILITY COORDINATOR tasks have been delegated.

3. **Requirements for certified operators.** OPERATING AUTHORITIES and entities must ensure that these delegated tasks are carried out by NERC-certified RELIABILITY COORDINATOR operators.

4. **Auditing delegated tasks**. Entities that accept delegation of RELIABILITY COORDINATOR tasks, may have these tasks audited under the NERC RELIABILITY COORDINATOR audit program.

C. Common Tasks for Next-Day and Current-Day Operations

Requirements

1. In all time frames RELIABILITY COORDINATORS are responsible for the following:

   1.1. **Assessing CONTINGENCY situations.** The RELIABILITY COORDINATOR shall coordinate operations in regards to SOLS and IROLS for real time and next day operations for its RELIABILITY COORDINATOR AREA including thermal, voltage and stability related analysis. Assessments shall be conducted, up to and including next-day, at the CONTROL AREA level with any identified potential SOL violations reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR is to ensure that its WIDE AREA view is modeled to ensure coordinated operations.

   1.2. **Determining IROLS.** The RELIABILITY COORDINATOR shall determine IROLS based on local, regional and interregional studies. The RELIABILITY COORDINATOR must be aware that an IROL violation can be created during multiple, normally non-critical outage conditions and, as such, the RELIABILITY COORDINATOR must be knowledgeable of events that could lead to such an occurrence. The RELIABILITY COORDINATOR is responsible for disseminating this information within its RELIABILITY COORDINATOR AREA and to neighboring RELIABILITY COORDINATORS.

   1.3. **Assuring OPERATING AUTHORITIES shall not BURDEN others.** The RELIABILITY COORDINATOR shall ensure that all OPERATING AUTHORITIES will operate to prevent the likelihood that a disturbance, action, or non-action in its RELIABILITY COORDINATOR AREA will result in a SOL or IROL violation in another area of the INTERCONNECTION. Doing otherwise is considered a BURDEN that one OPERATING AUTHORITY places on another. In instances where there is a difference in derived limits, the BULK ELECTRIC SYSTEM shall always be operated by the RELIABILITY COORDINATOR and its OPERATING AUTHORITIES to the most limiting parameter.

   1.4. **Operating under known conditions.** The RELIABILITY COORDINATORS shall ensure OPERATING AUTHORITIES always operate their OPERATING AUTHORITY AREA under known and studied conditions and also ensure they reassess and reposture their systems following CONTINGENCY events without delay, and no longer than 30 minutes[3], regardless of the number of CONTINGENCY events that occur or the status of their monitoring, operating and analysis tools.

   1.5. **Total Transfer Capability or Available Transfer Capability and transmission coordination.** The RELIABILITY COORDINATOR shall make known to OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA, SOLs or IROLs within its WIDE AREA view. The OPERATING AUTHORITY shall respect these SOLs or IROLs in accordance with filed tariffs and regional TTC/ATC calculation processes.

[3] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

1.6. Communications. The RELIABILITY COORDINATOR shall issue directives in a clear, concise, definitive manner. The RELIABILITY COORDINATOR shall receive a response from the person receiving the directive that repeats the information given. The RELIABILITY COORDINATOR shall acknowledge the statement as correct or repeat the original statement to resolve misunderstandings.

D. Next-Day Operations

Requirements

1. **Performing reliability analysis and system studies.** The RELIABILITY COORDINATOR shall conduct next-day reliability analyses for its RELIABILITY COORDINATOR AREA to ensure that the BULK ELECTRIC SYSTEM can be operated reliably in anticipated normal and CONTINGENCY event conditions.

    1.1. **Contingency analysis.** The RELIABILITY COORDINATOR shall conduct CONTINGENCY analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.

    1.2. **Considering parallel flows.** The RELIABILITY COORDINATOR shall pay particular attention to parallel flows to ensure one RELIABILITY COORDINATOR AREA does not place an unacceptable or undue BURDEN on an adjacent RELIABILITY COORDINATOR AREA.

2. **Sharing information.** Each OPERATING AUTHORITY in the RELIABILITY COORDINATOR AREA shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known INTERCHANGE TRANSACTIONS. This information shall be available by 1200 Central Standard Time for the Eastern INTERCONNECTION, and 1200 Pacific Standard Time for the Western INTERCONNECTION.

3. **Developing action plans.** The RELIABILITY COORDINATOR shall, in conjunction with its OPERATING AUTHORITIES, develop action plans that may be required including reconfiguration of the transmission system, redispatching of generation, reduction or curtailment of INTERCHANGE TRANSACTIONS, or reducing load to return transmission loading to within acceptable SOLs or IROLs.

4. **Sharing study results**. The RELIABILITY COORDINATOR shall share the results of its system studies, when conditions warrant or upon request, with other RELIABILITY COORDINATORS, and OPERATING AUTHORITIES within its RELIABILITY COORDINATION AREA. Study results shall be available no later than 1500 Central Standard Time for the Eastern INTERCONNECTION, and 1500 Pacific Standard Time for the Western INTERCONNECTION, unless circumstances warrant otherwise.

5. **Communication of results of next-day reliability analyses.** Whenever conditions warrant, the RELIABILITY COORDINATOR shall initiate a conference call or other appropriate communications to address the results of its reliability analyses.

6. **Alerts.** If the results of these studies indicate potential SOL or IROL violations, the RELIABILITY COORDINATORS shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS) and direct their OPERATING AUTHORITIES to take any necessary action the RELIABILITY COORDINATOR deems appropriate to address the potential SOL or IROL violation.

7. **Operating Authority Response.** OPERATING AUTHORITIES shall comply with the directives of its RELIABILITY COORDINATOR based on the next day assessments in the same manner in which the OPERATING AUTHORITY would comply during real time operating events.

E. Current-Day Operations

Requirements

1. **Monitoring and Coordination**

1.1. **WIDE AREA view.** The RELIABILITY COORDINATOR shall monitor all BULK ELECTRIC SYSTEM facilities within its RELIABILITY COORDINATOR AREA and adjacent RELIABILITY COORDINATOR AREAS as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the RELIABILITY COORDINATOR is able to determine any potential SOL and IROL violations within its RELIABILITY COORDINATOR AREA. This responsibility may require RELIABILITY COORDINATORS to receive sub-transmission information not normally monitored by their Energy Management System to assist in IROL determination.

1.1.1. **WIDE AREA view – coordination.** When a neighboring RELIABILITY COORDINATOR is aware of an external operational concern, such as declining voltages, excessive reactive flows, or an IROL violation, the neighboring RELIABILITY COORDINATOR shall contact the RELIABILITY COORDINATOR in whose RELIABILITY COORDINATOR AREA the operational concern was observed. They shall coordinate any actions, including emergency assistance, required by the RELIABILITY COORDINATOR in mitigating the operational concern.

1.2. **Facility status.** The RELIABILITY COORDINATOR must know the status of all current critical facilities whose failure, degradation, or disconnection could result in an SOL or IROL violation. RELIABILITY COORDINATORS must also know the status of any facilities that may be required to assist area restoration objectives.

1.3. **Situational awareness.** The RELIABILITY COORDINATOR shall be continuously aware of conditions within its RELIABILITY COORDINATOR AREA and include this information in its reliability assessments. To accomplish this objective the RELIABILITY COORDINATOR shall monitor its RELIABILITY COORDINATOR AREA parameters, including but not limited to the following:

1.3.1. Current status of BULK ELECTRIC SYSTEM elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems and system loading

1.3.2. Current pre-CONTINGENCY element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate an SOL or IROL violation including the plan's viability and scope

1.3.3. Current post- CONTINGENCY element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate an SOL or IROL including the plan's viability and scope

1.3.4. System real and reactive reserves (actual versus required)

1.3.5. Capacity and energy adequacy conditions

1.3.6. Current ACE for all its CONTROL AREAS

1.3.7. Current local or TLR procedures in effect

1.3.8. Planned generation dispatches

1.3.9. Planned transmission or generation outages

1.3.10. CONTINGENCY events

1.4. **BULK ELECTRIC SYSTEM monitoring**. The RELIABILITY COORDINATOR shall monitor BULK ELECTRIC SYSTEM parameters that may have significant impacts upon the RELIABILITY COORDINATOR AREA and with neighboring RELIABILITY COORDINATOR AREAS with respect to:

1.4.1. **INTERCHANGE TRANSACTION information.** The RELIABILITY COORDINATOR shall be aware of all INTERCHANGE TRANSACTIONS that wheel-through, source, or sink in its RELIABILITY COORDINATOR AREA and make that INTERCHANGE TRANSACTION information available to all RELIABILITY COORDINATORS in the INTERCONNECTION. (Note: This requirement is satisfied by the Interchange Distribution Calculator and E-Tag process for the Eastern INTERCONNECTION.)

1.4.2. **Pending INTERCHANGE SCHEDULES to identify potential flow impacts.** As portions of the transmission system approach or exceed SOLs or IROLs, the RELIABILITY COORDINATOR shall work with the OPERATING AUTHORITIES to evaluate and assess any additional INTERCHANGE SCHEDULES that would violate those limits. If the potential or actual IROL violation cannot be avoided through proactive intervention, the RELIABILITY COORDINATOR shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes[4]. All resources, including load shedding shall be available to the RELIABILITY COORDINATOR in addressing a potential or actual SOL or IROL violation.

1.4.3. **Availability or shortage of OPERATING RESERVES needed to maintain reliability.** The RELIABILITY COORDINATOR shall monitor CONTROL AREA parameters to ensure that the required amount of OPERATING RESERVES are provided and available as required to meet NERC Control Performance Standard and Disturbance Control Standards requirements. If necessary, the RELIABILITY COORDINATOR shall direct the CONTROL AREAS in the RELIABILITY COORDINATOR AREA to arrange for assistance from neighboring areas (CONTROL AREAS, REGIONS, etc.). The RELIABILITY COORDINATOR shall issue ENERGY EMERGENCY Alerts, as needed, and at the request of LOAD SERVING ENTITIES.

1.4.4. **Actual flows versus limits.** The RELIABILITY COORDINATOR shall identify the cause of the potential or actual IROL violations and initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes[5]. All resources, including load shedding,

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[4] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

[5] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

shall be available to the RELIABILITY COORDINATOR in addressing a SOL or IROL violation.

1.4.5. **Time error correction and GMD notification.** The RELIABILITY COORDINATOR will communicate start and end times for time error corrections to the CONTROL AREAS within its RELIABILITY AREA. The RELIABILITY COORDINATOR will ensure all CONTROL AREAS are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

1.4.6. **RELIABILITY COORDINATOR coordination with other Regions.** The RELIABILITY COORDINATOR shall participate in NERC Hotline discussions, assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The RELIABILITY COORDINATOR will disseminate information within its RELIABILITY COORDINATOR AREA.

1.4.7. **System frequency and resolution of significant frequency errors, deviations, and real-time trends.** The RELIABILITY COORDINATOR shall monitor system frequency and its CONTROL AREAS' performance and direct any necessary rebalancing to return to CPS and DCS compliance. All resources, including firm load shedding, shall be utilized as directed by a RELIABILITY COORDINATOR to relieve the emergent condition.

1.4.8. **Sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY COORDINATOR AREAS.** The RELIABILITY COORDINATOR shall coordinate with other RELIABILITY COORDINATORS and CONTROL AREAS, as needed, to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. This would include coordination of pending generation and transmission maintenance outages in both the real time and next day reliability analysis timeframes.

1.4.9. **Availability or shortage of Interconnected Operations Services required (in applicable RELIABILITY COORDINATOR AREAS).** As necessary, the RELIABILITY COORDINATOR shall assist the CONTROL AREAS in its RELIABILITY AREA in arranging for assistance from neighboring RELIABILITY COORDINATOR AREAS or CONTROL AREAS.

1.4.10. **Individual CONTROL AREA or RELIABILITY COORDINATOR AREA ACE (in applicable RELIABILITY AREAS).** The RELIABILITY COORDINATOR will identify sources of large AREA CONTROL ERRORS that may be contributing to frequency, time error, or inadvertent interchange and will discuss corrective actions with the appropriate CONTROL AREA operator. If a frequency, time error, or inadvertent problem occurs outside of the RELIABILITY COORDINATOR AREA, the RELIABILITY COORDINATOR will initiate a NERC Hotline call to discuss the frequency, time error, or inadvertent interchange with other RELIABILITY COORDINATORS. The RELIABILITY COORDINATOR shall direct its CONTROL AREAS to comply with CPS and DCS as indicated in section 1.4.7 above.

1.4.11. Use of Special Protection Systems (in applicable RELIABILITY COORDINATOR AREAS). Whenever a Special Protection System that may have an inter-CONTROL AREA or inter-RELIABILITY COORDINATOR AREA impact (e.g. could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the RELIABILITY COORDINATORS shall be aware of the impact of the operation on inter-Area flows. The RELIABILITY COORDINATOR shall be kept informed of the status of the Special Protection System including any degradation or potential failure to operate as expected.

1.5. Communication with RELIABILITY COORDINATORS of potential problems. The RELIABILITY COORDINATOR who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its RELIABILITY COORDINATOR AREA shall issue an alert to all CONTROL AREAS and TRANSMISSION OPERATING ENTITIES in its RELIABILITY AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the Reliability Coordinator Information System without delay. The RELIABILITY COORDINATOR will disseminate this information to its OPERATING AUTHORITIES.

1.6. Provide other coordination services as appropriate and as requested by the CONTROL AREAS within its RELIABILITY COORDINATOR AREA and neighboring RELIABILITY COORDINATOR AREAS. The RELIABILITY COORDINATOR shall confirm reliability assessment results and determine the effects within its own and adjacent RELIABILITY COORDINATOR AREAS. This action includes discussing options to mitigate potential or actual SOL or IROL violations and taking actions as necessary as to always act in the best interests of the INTERCONNECTION at all times.

F. Emergency Operations

Requirements

1. **Mitigating SOL and IROL violations.** Regardless of the process it uses, the RELIABILITY COORDINATOR shall direct its OPERATING AUTHORITIES to return the transmission system to within the IROL as soon as possible, but no longer than 30 minutes. With this in mind, RELIABILITY COORDINATORS and their OPERATING AUTHORITIES must be aware that Transmission Loading Relief (TLR) procedures may not be able to mitigate the SOL or IROL violation in a timely fashion. Under these circumstances other actions such as reconfiguration, redispatch or load shedding may be necessary until the relief requested by the TLR process is achieved. In these instances the RELIABILITY COORDINATOR shall direct and OPERATING AUTHORITIES shall comply with the more timely requests.

2. **Implementing emergency procedures.** If the RELIABILITY COORDINATOR deems that IROL violations are imminent, the RELIABILITY COORDINATOR shall have the authority and obligation to immediately direct its OPERATING AUTHORITIES to redispatch generation, reconfigure transmission, manage INTERCHANGE TRANSACTIONS, or reduce system demand to mitigate the IROL violation until INTERCHANGE TRANSACTIONS can be reduced utilizing a transmission loading relief procedure, or other procedures, to return the system to a reliable state. The RELIABILITY COORDINATOR shall coordinate these emergency procedures with other RELIABILITY COORDINATORS as needed. [See also Policy 5, "Emergency Operations"]

3. **Implementing relief procedures.** If transmission loading progresses or is projected to violate a SOL or IROL, the RELIABILITY COORDINATOR will perform the following procedures as necessary:

   3.1. **Selecting transmission loading relief procedure.** The RELIABILITY COORDINATOR experiencing a potential or actual SOL or IROL violation on the transmission system within its RELIABILITY COORDINATOR AREA shall, at its discretion, select from either a "local" (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure, such as those listed in Appendix 9C1, 9C2, or 9C3

   3.2. **Using local transmission loading relief procedure.** The RELIABILITY COORDINATOR may use local transmission loading relief or congestion management procedures, provided the TRANSMISSION OPERATING ENTITY experiencing the potential or actual SOL or IROL violation is a party to those procedures.

   3.3. **Using a local procedure with an INTERCONNECTION-wide procedure.** A RELIABILITY COORDINATOR may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, the RELIABILITY COORDINATOR is obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY COORDINATOR desires to use a local procedure *as a substitute* for curtailments as directed by the INTERCONNECTION-wide procedure, it may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.

   3.4. **Complying with procedures.** When implemented, all RELIABILITY COORDINATORS shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.

3.5. **Complying with interchange policies.** During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY COORDINATORS and OPERATING AUTHORITIES shall comply with the Requirements of Policy 3, Section C, "Interchange Schedule Standards."

4. **Determining causes of Interconnection frequency error.** Any RELIABILITY COORDINATOR noticing an INTERCONNECTION frequency error in excess of 0.03 Hz (Eastern INTERCONNECTION) or 0.05 Hz (Western and ERCOT INTERCONNECTIONS) for more than 20 minutes shall initiate a NERC Hotline conference call, or notification via the Reliability Coordinator Information System, to determine the CONTROL AREA(S) with the energy emergency or control problem.

4.1. If a RELIABILITY COORDINATOR determines that one or more of its CONTROL AREAS is contributing to the frequency error, the RELIABILITY COORDINATOR shall direct those CONTROL AREA(S) to immediately comply with CPS and DCS requirements by using all resources available to it, including load shedding. The CONTROL AREA(S) shall comply with the RELIABILITY COORDINATOR request.

5. **Authority to provide emergency assistance.** The RELIABILITY COORDINATOR shall have the authority to take or direct whatever action is needed, including load shedding, to mitigate an energy emergency within its RELIABILITY COORDINATOR AREA. OPERATING AUTHORITIES shall ensure the directive of the RELIABILITY COORDINATOR is implemented. RELIABILITY COORDINATORS shall provide assistance to other RELIABILITY COORDINATORS experiencing an energy emergency in accordance with Appendix 5C, Subsection A, "Energy Emergency Alerts."

6. **Communication of Energy Emergencies.** The RELIABILITY COORDINATOR that is experiencing a potential or actual Energy Emergency within any CONTROL AREA, RESERVE-SHARING GROUP, or LOAD-SERVING ENTITY within its RELIABILITY COORDINATOR AREA shall initiate an Energy Emergency Alert as detailed in Appendix 5C, Subsection A – "Energy Emergency Alert Levels." The RELIABILITY COORDINATOR shall also act to mitigate the emergency condition, including a request for emergency assistance if required.

G. System Restoration

Requirements

1. **Operating Authority restoration plans.** The RELIABILITY COORDINATOR shall be aware of each OPERATING AUTHORITY'S restoration plan in its RELIABILITY COORDINATOR AREA in accordance with NERC and Regional requirements. During system restoration, the RELIABILITY COORDINATOR shall monitor restoration progress and coordinate any needed assistance.

2. **Reliability Coordinator restoration plan.** The RELIABILITY COORDINATOR shall have a RELIABILITY COORDINATOR AREA restoration plan that provides coordination between individual OPERATING AUTHORITY restoration plans and that ensures reliability is maintained during system restoration events.

3. **Reliability Coordinator is the primary contact.** The RELIABILITY COORDINATOR shall serve as the primary contact for disseminating information regarding restoration to neighboring RELIABILITY COORDINATORS and OPERATING AUTHORITIES not immediately involved in restoration.

4. **Re-synchronizing islands.** RELIABILITY COORDINATORS shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to BURDEN adjacent OPERATING AUTHORITIES or RELIABILITY COORDINATOR AREAS.

   4.1. **Reestablishing normal operations.** The RELIABILITY COORDINATOR shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.

H. Coordination Agreements and Data Sharing

Requirements

1. **Coordination agreements.** The RELIABILITY COORDINATOR must have clear, comprehensive coordination agreements with adjacent RELIABILITY COORDINATORS to ensure that SOL or IROL violation mitigation requiring actions in adjacent RELIABILITY COORDINATOR AREAS are coordinated.

2. **Data requirements.** The RELIABILITY COORDINATOR shall determine the data requirements to support its reliability coordination tasks and shall request such data from its OPERATING AUTHORITIES or adjacent RELIABILITY COORDINATORS, in accordance with the provisions of Policy 4, "System Coordination."

3. **Data exchange.** The RELIABILITY COORDINATOR or its OPERATING AUTHORITIES shall provide, or arrange provisions for, data exchange to other RELIABILITY COORDINATORS or OPERATING AUTHORITIES via the Interregional Security Network or RCIS network as required by NERC policy.

I. Facility

Requirements

1. RELIABILITY COORDINATORS shall have the facilities to perform their responsibilities, including:

   1.1. **Communications.** RELIABILITY COORDINATORS shall have adequate communications (voice and data links) to appropriate entities within its RELIABILITY COORDINATOR AREA, which are staffed and available to act in addressing a real time emergency condition.

   1.2. **Timely dissemination of information.** This includes multi directional capabilities between an OPERATING AUTHORITY and its RELIABILITY COORDINATOR and also from a RELIABILITY COORDINATOR to its neighboring RELIABILITY COORDINATOR(S) for both voice and data exchange as required to meet reliability needs of the INTERCONNECTION.

   1.3. **Monitoring capability.** Detailed real-time monitoring capability of the RELIABILITY COORDINATOR AREA and sufficient monitoring capability of the surrounding RELIABILITY COORDINATOR AREAS to ensure that potential or actual SOL or IROL violations are identified. Monitoring systems shall provide information that can be easily understood and interpreted by the RELIABILITY COORDINATOR, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure.

      1.3.1. RELIABILITY COORDINATORS shall monitor BULK ELECTRIC SYSTEM elements (generators, transmission lines, busses, transformers, breakers, etc.) that could result in SOL or IROL violations within its RELIABILITY COORDINATOR AREA. This monitoring overview shall include both real and reactive power system flows, and OPERATING RESERVES, and the status of BULK ELECTRIC SYSTEM elements that are or could be critical to SOLs and IROLs and system restoration requirements within its RELIABILITY COORDINATOR AREA.

   1.4. **Study and analysis tools.**

      1.4.1. **Analysis tools.** The RELIABILITY COORDINATOR shall have adequate analysis tools such as State Estimation, pre- and post-CONTINGENCY analysis capabilities (thermal, stability, and voltage) and WIDE AREA overview displays.

      1.4.2. **Continuous monitoring of RELIABILITY COORDINATOR AREA.** The RELIABILITY COORDINATOR shall continuously monitor its RELIABILITY COORDINATOR AREA. This includes the provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Backup provisions shall ensure SOL and IROL monitoring and derivations continues if the main monitoring system is unavailable.

      1.4.3. **Availability of analysis capabilities.** RELIABILITY COORDINATOR analysis tools shall be under the control of the RELIABILITY COORDINATOR, including approvals for planned maintenance. Procedures shall be in place to mitigate the affects of analysis tool outages.

J. Staffing

Requirements

The minimum training requirements will be moved to Policy 8 upon its next revision.

1. RELIABILITY COORDINATORS shall have adequate staff and facilities:

   1.1. **Staffing and training**. The RELIABILITY COORDINATOR shall be staffed with adequately trained and NERC-Certified RELIABILITY COORDINATOR operators, 24 hours/day, seven days/week. The RELIABILITY COORDINATOR must have detailed knowledge of its RELIABILITY COORDINATOR AREA, its facilities, and associated OPERATING AUTHORITIES' processes including emergency procedures and restoration objectives. Training for RELIABILITY COORDINATOR operators shall meet or exceed a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

   1.2. **Knowledge of the RELIABILITY COORDINATOR AREA**. The RELIABILITY COORDINATOR shall have a comprehensive understanding of its RELIABILITY COORDINATOR AREA and interaction with neighboring RELIABILITY COORDINATOR AREAS. Although OPERATING AUTHORITIES have the most detailed knowledge of their particular systems, the RELIABILITY COORDINATOR must have an extensive understanding of the OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA, such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. The RELIABILITY COORDINATOR shall place particular attention on SOLs and IROLs and intertie facility limits. The RELIABILITY COORDINATOR shall ensure protocols are in place to allow the RELIABILITY COORDINATOR to have the best available information at all times.

   1.3. **Standards of Conduct**. The entity responsible for the RELIABILITY COORDINATOR function shall sign and adhere to the NERC RELIABILITY COORDINATOR Standards of Conduct.

MSJ Rebuttal Exhibit 2 –
NERC Control Area Readiness Audit Report

Control Area Readiness Audit Report

LG&E Energy Control Area
May 19–20, 2004
Burgin, KY
Louisville, KY

North American Electric Reliability Council

Table of Contents

Introduction and Audit Process

In response to the August 14, 2003, blackout on February 10, 2004, the NERC Board of Trustees committed to take immediate actions to strengthen the reliability of the North American bulk electric system. Specifically, the board adopted the recommendations of the NERC Steering Group that investigated the August 14, 2003, blackout. These recommendations included:

- A list of specific actions to correct the deficiencies that led to the August 14, blackout;
- Near-term strategic initiatives by NERC and its regional reliability councils to strengthen compliance with existing standards and to formally track completion of recommended actions from August 14, and other significant power system events; and
- Longer-term technical initiatives to prevent or mitigate the impacts of future cascading blackouts.

NERC tasked the readiness audit team with assessing the degree to which the control area meets their responsibilities that are defined as:

> "The control area authority is responsible for the safe and reliable operation of their portion of the bulk electric system in cooperation with neighboring control areas and their reliability authority."

The audit process includes:

- A self-assessment questionnaire for the control area being audited
- Questionnaires for neighboring control areas
- A questionnaire to the reliability coordinator
- A two-day, on-site audit by a selected audit team

Pre-audit information (responses to the self-assessment questionnaire, a set of questions and guidelines to assist the audit team in the on-site audit, and copies of some of the documentation provided by the control area being audited) was sent to the audit team to assist them in their readiness evaluation. The team met prior to the on-site visit to complete necessary preparations for the audit. This preparation included discussing and reviewing interview assignments, the audit process, interview questions, and questionnaire responses.

Participants

Director Transmission
Manager Transmission System Operations
Group Leader, System Operations Engineering
Group Leader, Electric System Coordination
Group Leader, Electric System Coordination
Group Leader, Trainer and NERC Compliance
System Operations Engineer
Manager, Transmission Lines Services
System Analyst
System Operations Engineer
Network System Administrator
System Coordinator
Manager of AGC Operations
Director of Marketing
SR Electrical Engineer
System Supervisor
Group Leader, Transmission Planning
Manager, Transmission Planning and Substations

Audit Team

Paul Reber, NERC
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Norm Jary, Hydro One
Jagjit Singh, Salt River Project
John Kueck, FERC

Executive Summary

The team found Louisville Gas and Electric Energy (LGEE) had a well-run control area that is ready to meet the challenges of summer operation this year. The LGEE operations staff takes pride in its operations and is knowledgeable about how to operate the control area. Everyone has a "let's get it done" attitude. LGEE has two control centers, each with an up-to-date Energy Management System (EMS). LGEE keeps operators familiar with all job functions by rotating them through all positions at each control center and rotating functions between control centers on a regular basis. LGEE operations have functional control of the EMS maintenance and work very closely with corporate information technology for communications systems support.

The readiness of LGEE to meet the requirements of control area operation is discussed by specific area of the audit process below. Supporting and backup information is given in the body of this report.

1. Agreements and Staffing

All LGEE operators and their supervisors are NERC certified at the reliability coordinator level including the group leader positions at each control center. The audit team could not find a signed agreement between Midwest ISO (MISO) and LGEE for reliability coordination services. Operators were not generally familiar with documentation. LGEE cyber security was good and the physical security was sufficient, although minimal compared with other security systems at other control centers. The staff was knowledgeable. Initial training is good and well documented in the individual employee training book. LGEE needs to allow more time for training, needs to develop goals and objectives for its training program, and needs to measure the training results against goals and objectives.

2. Authority

The authority of the operators to take necessary actions was documented in their job descriptions and in a letter. The operators had copies of the job descriptions and the letter in the control room. The team believes that the operators would take the necessary action, including interruption of firm load, if necessary. The team is not sure that the operators will follow a directive issued by the reliability coordinator unless they agree with the directive.

3. Planning

As part of the planning process, LGEE evaluates all possible single contingencies and critical double contingencies. Planners verify study results against actual system condition to verify their model. LGEE does not use of Special Protections Schemes (SPS). Because LGEE has a "rock solid" transmission system, planning practices do not require the use of SPS. LGEE meets all East Central Area Reliability Council (ECAR) and NERC planning criteria.

4. Monitoring

LGEE has two control centers with separate and different model Energy Management Systems (EMS). One is from the former Kentucky Utilities system and the other from former Louisville Gas and Electric system. Each system performs well and has current updates from its respective EMS vendor. Each has an alarm system that prioritizes the alarms. LGEE has developed a system that monitors the alarms and warns the operators when any alarm point becomes inactive.

Each of the two control centers can back up the other in the event of a control center evacuation. However, if the EMS or communications from one center is completely down, the portion of the LGEE transmission system covered by the inactive control center could not be operated from the other. Each control center has single points of failure that could result from fire, loss of power, or loss of communication connections. LGEE is improving the capabilities of the control centers so they will be mutually redundant and the entire system can be operated from either center if the other is unavailable.

LGEE does not run state estimation or contingency analysis. LGEE does not have frequency monitors widely dispersed across its system. It has a good geographic voltage monitoring display. It monitors static reactive reserves in five regions and total reactive reserves within LGEE. Transmission congestion is primarily handled by the reliability coordinator.

A separate group within LGEE marketing handles load and generation balance and monitors contingency reserves. LGEE uses a standard load-forecasting program for short-term resource planning. Meeting reserve requirements arevery important to LGEE and are part of the operator performance evaluation. The team found that this group put a high priority on reliability, as did the other operating areas.

5. System Restoration

LGEE appears to have a good system restoration plan. It also has a ten-step plan to respond to declining frequency, which includes islanding generation with load in the final step. While the plans were good and the operators felt they could implement them, the documentation was not well organized.

6. Delegation of Reliability Coordination Functions

The reliability coordinator does not delegate any reliability coordination functions to the control area.

7. Outage Coordination

The regional transmission operator is largely involved with the transmission scheduling and coordination with neighboring systems. LGEE also has an outage scheduling system that helps coordinate with MISO. To allow time for their evaluation, LGEE and MISO require a minimum of two weeks notice for planned outages.

8. Relaying

LGEE has not had problems with relay operations. Operations must be notified and approve removal of protection devices.

9. Capacity and Energy Emergency Plan

LGEE has a complete capacity and energy emergency plan but the documentation could be better organized.

10. Tracking Changes

LGEE has a documented plan to distribute notices of policy and procedure changes. The team recommends that LGEE add a shift-change check-off sheet to ensure that necessary information is passed to the next shift.

11. Vegetation Management

LGEE has a "best practice" vegetation management program for its transmission system. It does not trim right-of-way; it clears them. LGEE has good cooperation with state and other governmental agencies in obtaining the necessary permitting and permission to clear the right-of-way. The operators do not recall any recent vegetation related problems involving transmission lines.

12. Nuclear Power

LGEE has no nuclear plants on its system or electrically close on neighboring systems.

Recommendations

The NERC LGEE readiness audit team makes the following recommendations to LGEE:

- Complete dual port Remote Terminal Unit (RTU) and redundant communications installation to truly have two independent control centers

LGEE is adding dual porting to all of the tie points, generation, and critical transmission elements so that either control center can operate the control area if the other is lost. The team recommends that this project be completed in a timely manner. LGEE should also study and separate the primary and backup equipment at each site, to reduce the risk of losing the entire EMS for a single equipment contingency.

- LGEE needs to allow more time for training

To provide adequate time for training and relief, the team recommends that LGEE add three personnel to the shift operations at each control center. LGEE should also conduct more drills as a part of its training program.

- LGEE needs to develop training goals

LGEE should develop clear goals and objectives for the training program, including individual annual goals. The team also recommends that individual training be tracked in a computer database that can be sorted to provide data to measure company and individual performance against the stated goals and objectives. The training program should also be aligned with procedures (such as the emergency response and system restoration) so that the operators become familiar with them.

- State Estimation and Contingency Analysis should be added to the EMS

LGEE is adding a state estimator and contingency analysis to its system. The team recommends that this project be completed and operational within one year. LGEE should work with MISO to get the state estimator results from MISO.

- MISO and LGEE need to resolve authority issues

The team believes that the operators will exercise their authority and take whatever actions are necessary to relieve congestion on the system. However, the team does not believe that they will follow directions from the reliability coordinator unless they are in agreement with these directions. Part of this hesitation results from a lack of confidence in the reliability coordinator. Management shares this lack of confidence. LGEE management believes that their confidence should improve as MISO develops familiarity with the LGEE electrical system.

The team believes that the reliability coordinator must have this authority and LGEE and MISO must resolve the issues that interfere with the rapid execution of directives from MISO in times of stress. The team supports discussing, understanding and agreeing on a directive, when time permits, and is not suggesting that this healthy discussion process be eliminated.

- Documentation needs to be reviewed

The team recommends the following concerning documentation:

- LGEE should work on organizing and updating documentation.
- Use the documentation to aide in training. It should also be in a form to be used as reference by the operating staff.
- Develop an overall index of documentation, listing all procedures by subject, revision, and date. Out-of-date or superceded procedures should be removed.
- Add emergency training courses taken and hours successfully completed to the front of the operator training record book.
- Develop a shift-change check-off list.
- Resolve the conflict in authority that exists in different documents in the Emergency Procedure Manual.
- Upgrade the physical security.

The team supports the physical security upgrade that LGEE is in process of implementing.

- Add additional frequency monitors

To help the operators identify seams on the LGEE system if the Eastern Interconnection would split, the team recommends that LGEE add frequency monitors to its system and telemeter them into the control rooms. LGEE is in the process of adding three frequency monitors, and the team feels completion of this project will provide adequate monitoring. The team also feels that the frequency monitors at the plants could also be used to assist in this effort.

- Investigate use of a Dispatcher Training Simulator (DTS)

The team recommends that the LGEE monitor the use of dispatcher training simulators to provide simulator training to LGEE staff. The team realizes that a DTS is expensive and requires extensive support. Having its own DTS may not be practical for a company the size of LGEE. As an alternate, LGEE could investigate the use of regional simulators that may exist in places like MISO. By the next audit, LGEE should have a DTS, or do operator training on a DTS other than their own, or explain what it has done to provide operators with training in realistic operating situations.

- Upgrade fault recorders

LGEE has several types of fault reorders. Not all of them are capable of time synchronization. The team recommends that LGEE add time synchronization to critical fault recorders. ECAR is in the process of establishing a requirement for time stamping.

- LGEE should ask ECAR for formal recognition and documentation as a certified control area.

LGEE should work with ECAR to provide formal recognition and documentation of LGEE as a control area within ECAR.

On-site Review Notes

LG&E Energy LLC (LGEE), headquartered in Louisville, Kentucky, is a diversified energy services company. It was formed by the merger of the Louisville Gas and Electric Company and Kentucky Utilities. Its mission is to provide exceptional value to its customers and shareholders as it embraces the era of competition in the energy industry. Louisville Gas and Electric Company, an electric and gas utility, operates in the state of Kentucky and is regulated by the Kentucky Public Services Commission. It serves customers in Louisville and sixteen surrounding counties. Kentucky Utilities Company, an electricity company based in Lexington, Kentucky, serves 77 Kentucky counties and five counties in Virginia.

LGEE serves 840,000 electric customers. It has generation capacity of 8,460 MW net and a transmission and distribution network that covers 27,000 square miles. It operates 40 miles of 500 kV transmission lines, 533 miles of 345 kV transmission lines, and 1,206 miles of 138 kV transmission lines. Its system has 1,052 breakers, 122 transformers, and 210 RTUs. Its summer peak load is 6,513 MW and its winter peak load is 5,706 MW.

1. Criteria and Compliance

1.1 Agreements

The control area must have agreements that establish their authority as a control area. The control area must have agreements that establish the reliability coordinator for its control area.

Audit Notes:

LGEE became a control area in 1998, when the two previous control areas of Kentucky Utilities and Louisville Gas and Electric were combined following the merger of the two utilities. It is recognized as a control area in the NERC Registry and by ECAR, but LGEE could not produce a document giving it authority to operate as a control area. LGEE should ask ECAR for formal recognition as a control area.

LGEE provided the Interconnection and Operating Agreement between MISO and LGEE establishing the authority of MISO as the reliability coordinator. This document was a Generator-Transmission Owner Agreement and did not reference the reliability coordinator authority. LGEE also provided the standard MISO transmission owners agreement that does give MISO the reliability coordination authority, and does not define the specific responsibilities of each organization.

	Applicable Documents	Dated	Version
1	MISO LGEE Interconnection and Operating Agreement	01/27/04	
2	Generator Transmission Owner Agreement		

1.2 Staff Certification

Control area operators must be NERC operator certified. The control area must have sufficient NERC operator certified staff for continuous coverage of the control area operating positions.

Audit Notes:

LGEE has ten NERC certified operators at each of the two transmission control centers. All operating positions at the generation desk are also certified. The transmission control centers have two positions staffed around the clock the interchange operator and the transmission operator. The operators alternate between the two jobs every day. The interchange operator does two functions: tag approvals and interchange accounting. One function is done at the Dix control center and the other at

Waterside control center. These two functions rotate between the Dix and Waterside operators each month. LGEE has a third position of group leader on weekday day shifts. All group leaders are NERC certified operators.

The operators must be NERC certified and complete the LGEE training before they can take a shift on their own. Trainees are paired with an experienced operator and do all functions under his/her direction.

	Applicable Documents	Dated	Version
1	Operator binder from Dix		
2	Operator binder from Waterside		
3	NERC operator certificates for all operating personnel and supervisors		

1.3 Security

Access to the control room must be controlled for security reasons.

Audit Notes:

Physical access control: LGEE provided documentation and demonstrated the control room security system. The team found this to be adequate for the control centers, although it was minimal compared with other security systems at other control areas. The team supports the LGEE is in the process of upgrading its security system, which the team supports.

Cyber Access Control: LGEE provided documentation and demonstrations of the cyber access controls and the team found this to be adequate for the control centers.

	Applicable Documents	Dated	Version
1	LGEE Corporate Security Policy		
2	NERC 2004 Cyber Security Assessment Program.		

1.4 Training

The control area operators must be adequately and effectively trained to perform their roles and responsibilities. The control area must have documents that outline the training plans for the control area operators. The control area must have training records and individual staff training records available for review.

Audit Notes:

LGEE has one person each assigned to manage the training at the Dix and Waterside control centers. The trainers keep a training record book for each operator. The operators keep their own book that contains the following:

- NERC Operator Certification Document
- Job Descriptions
- Job check-off sheets documenting mastery skills required for operators
- List of training the operator has completed with subject, time, and date taken
- Black Start Procedure
- Emergency Preparedness Plan
- NERC and MISO study guides

- NERC Code of Conduct
- Statement of Authority for operator action

The trainers at both locations review training materials and critical job functions (such as blackstart procedures) with operators semi-annually and document that review in the operator's training book.

LGEE also uses outside vendors to assist in training. It has purchased modular training programs that the operators can complete at their own pace. And, when operators are available, it sends them to ECAR and MISO training events.

LGEE keeps operators current on all control room positions by rotating their job assignments. The interchange operator and transmission operator change positions each day. The interchange operators at the two control centers rotate the tag approval process and the interchange accounting process between the Dix Waterside control centers monthly. Operators also visit neighboring control centers as time permits.

In general, LGEE does not use many drills. LGEE does two individual black start map board drills each year, which the trainers oversee. Each operator goes through the steps to black-start a unit, using the map board to demonstrate switching and transmission paths, but other areas of the company are not involved. LGEE does not conduct drills on control center evacuation. Due to manpower scheduling, the operators could not participate in a recent MISO regional restoration drill, however, the group leaders did participate.

LGEE selects its system operators from generation or electric service technical positions; substation experience is preferred. Operator candidates have a minimum of five years of experience but15 years of experience is more typical. It takes18 months to two years of training before the employee is allowed to operate on shift without direct oversight. Preparation for shift responsibilities largely consists of on the job training. LGEE does have a check-off sheet (included in the training record book) that lists the skills necessary for an operator. The employees' skills are reviewed and they are approved for shift responsibilities by the trainer, transmission group leader, and the manager of control centers before they are allowed to operate solo. The initial training of each employee is well documented in the training record book.

LGEE will not complete the five days of emergency procedures training by June 30, as recommended by NERC. Currently the amount of emergency procedures training completed by operators varies from zero to20 hours; five hours is the average, but the trainers expect the average to increase to 20 hours by the end of June. Because a cross-referenced summary of completed training is not available, it was difficult to track individual and overall progress toward completion of the NERC recommended training.

At each control center, LGEE has nine people covering two shift positions, including relief and training for the two positions. LGEE does not have enough time in the shift schedule to allow for adequate formal training. This leads to great difficulty in scheduling and uses a lot of overtime. It also prevents LGEE from fully participating in MISO and ECAR training activities and makes it difficult to conduct drills.

Individual training is documented in the individual training record books. LGEE does not keep records in a manner that make it possible to determine whether training is meeting its overall objectives. In general, LGEE does not have well documented training goals and objectives or a system to measure training performance.

LGEE does not have a Dispatcher Training Simulator.

	Applicable Documents	Dated	Version
1	Dix Training Record Book for individual		
2	Waterside Training Record Book for individual		
3	Brown Unit Black Start Simulation	12/15/03	
4	MISO Spring Power System Restoration	04/21/04	

2. Authority

The control area is responsible for establishing and authorizing the control area operator position that will have the on-shift responsibility for the safe and reliable operation of their portion of the bulk electric system in cooperation with neighboring control areas and its reliability coordinator.

Audit Notes:

The operators know they have the authority to take necessary action up to and including interrupting firm load, and the audit team feels that they would take any action they thought was necessary. The team also believes that management would stand behind their decision, as do the operators.

LGEE has included a Transmissions Operations Statement signed by the senior vice president of energy services in the individual training record books that states "the Transmission System Operator has the authority to take or direct actions during normal and emergency conditions up to and including shedding of firm load to prevent or alleviate operating security limit violations on the system."

The Emergency Procedures Manual Part 2 (Short Term) states "the system operators have been granted and are expected to use their authority to execute all plans and procedures up to and including shedding of firm system load without seeking approval from a higher authority from within the operators own control area." Later, in the same document, paragraph 11 states "for native load the contact for load curtailment will come from the executive management and will be implemented by the Director of Transmission." These statements conflict.

The authority between the operators in the control room is well understood. Normally they operate with consensus, however, if they cannot agree, the operator at the transmission desk has final authority. The transmission desk operator at the Dix control center has authority over the one at Waterside where they have joint operation, such as in interchange. But, the relationship between Dix and Waterside is not documented.

LGEE provided the team with the MISO Reliability Coordination Process Manual Section 3.1.4 specifies the functions of reliability coordinators. These include: the control and restoration of islanded areas and monitoring relevant parameters (such as interchange schedules, availability of operating reserves, actual flows versus limits, time error correction, system frequency deviations, shortage of interconnected operations services, and ACE deviations). Section 5.15 of this manual, Making Operating Decisions, states that the MISO will make operating decisions affecting the transmission system/facilities under its control. These decisions will be based on criteria including, but not limited to:

- Consultation with Control Area Operators
- Load Flow/Network Model
- Weather Conditions
- Scheduled Interchange
- Flow Impact Studies

- Contingency Analysis Studies
- MISO Flowgate Monitoring Tool
- Power Supply Monitoring Tool
- Scheduled Interchange Transactions

The team did not believe the above statements defined the authority between MISO and LGEE clearly enough, but neither LGEE operators nor management could provide better documentation. After discussions with LGEE operators, the team is still not sure that LGEE would interrupt firm load at the direction of MISO, unless it agreed that the action was necessary. Management is also hesitant to follow MISO directives if it thinks MISO may be in error. While the team agrees that questionable directives should be discussed, if time permits, the team emphasizes that load must be shed in an emergency when there is no time for discussion. Neither operators nor management completely trust the experience and judgment of MISO.

	Applicable Documents	Dated	Version
1	Emergency Procedures Manual		
2	Transmissions Operations Statement		
3	Dix Training Record Book for individual		
4	Waterside Training Record Book for individual		
5	MISO Reliability Coordination Process Manual	03/14/03	2.2

3. Planning Time Frame Responsibilities

The control area must have a process for day-ahead planning, as well as a process for longer-term planning, such as week-ahead, year-ahead, etc., for the operation and outage scheduling of transmission facilities and generation and reactive resources.

The control area must have agreements with its reliability coordinator to ensure that day-ahead and longer-term plans for the operation and outage scheduling of transmission facilities, generation, and reactive resources will not result in unacceptable bulk electric system reliability.

Audit Notes:
LGEE cooperates with MISO and ECAR in completing planning studies.

Both LGEE and MISO perform current-day and day-ahead modeling. The results usually agree but are sometimes different, usually because MISO has a wider area view, and LGEE has more accurate generation dispatch information. If a discrepancy occurs, MISO and LGEE share data and rerun the studies and then the LGEE and MISO planners resolve the differences. LGEE has a good working relationship with MISO and is confident in its studies.

LGEE operations planners study outage request schedules falling within a window from current-day and out to six months. Longer-range outages are studied by the system planning group. In both cases, effects of the outages are evaluated to single contingency and certain double contingencies (generation and transmission, double circuits, etc.), thus meeting NERC and ECAR standards. According to LGEE policy, reliability studies are performed to guarantee adequacy of supply to native load, not to support market activity.

As the transmission provider, MISO calculates LGEE Available Transfer Capacity (ATC) and also approves transactions for the LGEE control area. MISO has the responsibility to approve or deny transactions based on the ATC but LGEE can reject transactions as the control area.

There is a close relationship between planning and operations at LGEE. System planning develops line ratings and LGEE operates within those ratings. Some ratings are temperature dependent. They have no lines that they are aware of that would result in an operating security limit. Their ratings are based on thermal limits, not stability.

Both MISO and LGEE system planning do stability planning studies. LGEE only checks generators planned to be added to the system for stability during a close fault to confirm that the unit will remain on line. LGEE relies on ECAR studies for broader dynamic studies.

System planning uses planning studies to create system voltage schedules based on system load. The results of these studies are well documented in voltage and reactive schedules and are designed to maintain voltages above 90% after a contingency occurs. According to LGEE personnel, MISO is aware of this voltage criterion.

LGEE had a MISO terminal for three weeks in November 2003 at which time LGEE operations staff reviewed the MISO model for accuracy. MISO is also developing a web-based application so that MISO members can view the model from many remote locations. This summer, MISO is also going to review all of its 96,000 ICCP points to verify their accuracy.

To verify the models, LGEE compares the actual operating system conditions to the study conditions. Power factors at the generating stations are compared to the predicted power factors.

The audit team reviewed the connection contracts and found that generators are obligated to supply relay design and testing information and information necessary for planning studies.

	Applicable Documents	Dated	Version
1	Interconnection and Operating Agreement Bluegrass Generation Company	04/12/01	
2	Interconnection and Operating Agreement Cannelton Hydroelectric Project	12/03/03	

4. Real-Time Monitoring

4.1 General

The control area must provide the control area operators with effective, reliable computer and communication facilities for data and status monitoring, and voice communication at both the primary and the backup control facilities.

Audit Notes:

LGEE has two control centers with different model Emergency Management System (EMS) platforms. LGEE regularly updates the systems with both updated within the past two years. Each EMS has adequate monitoring and analysis capabilities as discussed in subsequent paragraphs of this section. Neither EMS runs state estimation or contingency analysis but LGEE is in the process of adding state estimation to one system and plans to add it to the other. LGEE alarms flowgates at 90% of the post-contingency emergency rating. LGEE determines the post-contingency flow by using the static Outage Transfer Distribution Factor (OTDF) values from studies. In the opinion of the team, this system is adequate if system, conditions are not changing. MISO does contingency analysis based on real-time conditions.

The team found that the voice and data communication facilities are adequate. LGEE has a single point of failure in the communication switch on the LGEE system but the operators can switch to the publicly switched system in the event of a failure.

The EMS maintenance personnel report directly to the operations department. The communications and network maintenance is done through the information technology department, but system operators can make the call-outs directly and prioritize maintenance work if necessary. All the operators interviewed agreed that this process provided a quick response to equipment problems.

4.2 Alarms

The control area operator must have effective and reliable alarming capability. This should be supported in the control area's EMS and/or Supervisory Control And Data Acquisition (SCADA) system by alarm priority.

Audit Notes:

LGEE uses the standard alarm packages provided by the two EMS vendors. Both alarm systems have 16 priority levels available, of which LGEE uses eight. The alarm priorities are color-coded on the display indicating the type of alarm and voltage class of the equipment monitored. The two highest priorities also have an audible alarm. Each control center's alarm priority numbering and color scheme is different. LGEE has not done performance monitoring of the alarm system to determine how many alarms it can handle before it overloads.

LGEE's philosophy is that the operator must take action when an audible alarm sounds. Priorities are used to try to avoid nuisance alarms. The operators feel that they get too many alarms at times and that the alarms priorities could be adjusted during emergencies to help them better manage the system.

LGEE gets an alarm when ICCP data is not flowing to MISO.

In response to the recommendations in the Northeast blackout report, LGEE is presently adding a program to monitor the status of its alarm system. If an alarm has been inactive, it verifies that the communication is still active and alarms the operator and pages IT support if a failure is suspected. This system is in place and being checked out now.

There are no audible alarms for RTU or communication failures at the Dix control center.

4.3 Plans for the Loss of Control Facilities

The control area must have a workable plan so it can continue to perform the control area functions required to maintain a reliable bulk electrical system following the sudden catastrophic loss of its primary control facility.

The control area must also have a workable plan to continue to perform the control area functions required to maintain a reliable bulk electrical system following the partial or full failure of its computer facilities or monitoring tools at the primary control facility.

Audit Notes:

LGEE has two operating control centers. When Kentucky Utilities and Louisville Gas and Electric merged, LGEE kept both control centers of the former companies in operation. Each control center operates its individual EMS and each has a terminal at the other center. Under most expected conditions, each control center can act as a backup to the other. In most cases, SCADA points only go to one control center (whichever center it went to under the old, two-company system). Therefore, if one center is inoperable, the remaining center cannot control those points. And, since some of the tie points would be missing, Automatic Generation Control (AGC) could not run.

LGEE is in the process of installing dual-ported RTUs at all the tie points, all generators, and at major internal substations. As LGEE completes these installations, it is providing redundant, diversely routed communication links to each control center. With applications such as AGC running at both control centers, LGEE will have true redundant backup centers, each able to operate independently from the other.

Each control center has redundant control systems and redundant connections to the corporate WAN. The team did find that some of the redundant equipment was located in close proximity, sometimes in the same computer racks.

The operators use both EMSs so they are familiar with each. They do not drill on transferring functions from one control center to the other as would be necessary during an emergency. They do move some functions between the two control centers during normal operations.

LGEE has a good business recovery plan. An emergency preparedness plan and business recovery plan for the transmission services provider and transmission information technology operations support provides short-term strategies in the event of an interruption to critical services (e.g. critical transmission line failure, computer program accessing and processing failure, data link failures and telecommunications facility failures). This procedure states that should the control center handling interchange scheduling and schedule approval task be the affected control center, the duties shall be transferred to the alternate control center considering both have the ability to perform these duties. If the control center handling switching clearance and transmission security needs to be evacuated, those tasks will be transferred to the other center as well. These function transfers will be coordinated by the events manager and with the recovery management team. Appropriate responses are described for scenarios such as:

- Failure of data link
- Failure of the Dix EMS
- Failure of the Waterside EMS
- Failure of TDS/Sybase on Waterside EMS
- Failure of critical data communication hubs
- Required evacuation of Waterside control center and Utility Power Sales control center (UPS)
- Required evacuation of Dix control center
- Catastrophic event at Waterside control center and UPS

	Applicable Documents	Dated	Version
1	Emergency Preparedness and Business Recovery Plan	12/08/03	

4.4 Monitoring Responsibilities

The control area operators must monitor operating data and status in real time operation, including:

- Multiple Frequency Monitoring
- Multiple Voltage Monitoring
- Facility Monitoring
- Transmission System Congestion

- Load Generation Balance
- Contingency Reserves
- Special Protection Systems
- Load Tap Changing (LTC) settings
- Status of rotating and static reactive resources

Audit Notes:
LGEE monitors all the above system parameters except for special protection systems because LGEE does not have any. In addition, the following are monitored:

- ACE and ACE trends
- Reactive Reserves
- EMS Alarms
- Weather data

Except for voltages, LGEE does not have a single overview display on the entire system at the Dix control center. LGEE is in the process of installing a dynamic large screen video display at Waterside and later at Dix that will provide this.

4.5 Frequency Monitoring

The control area operator must monitor frequency and direct actions to resolve significant frequency errors, and correct real-time trends that are indicative of potential developing problems. Frequency monitoring points should be of sufficient number and from several locations with sufficient area coverage to allow the control area operator to effectively monitor the control area, and be able to determine possible islands.

Audit Notes:
LGEE monitors frequency at three points, primarily for AGC and is adding three additional points (one in each of the Western, Mountain, and Central regions) to help identify system separation and islanding. Operators interviewed support adding the three additional frequency monitors.

LGEE has a ten-step process for arresting declining frequencies defined in the Emergency Operation Manual - Declining Frequency Procedures. The first eight steps are for increasingly more severe frequency events. The first five steps correspond to the ECAR automatic load shedding requirements. Steps 6 and 7 are manual load shedding steps. Step 8 defines how to island plants to attempt to maintain individual islands. The final two steps are for returning the system to normal.

The operators know at what frequency they would have to shed load to prevent further frequency decline. The operators told the audit team that generators trip at 58.2 Hz, however, management indicated that the generating units do not have frequency relays.

LGEE has not tested the generator governor responses during the past five years. LGEE does monitor the control area response to frequency deviations and uses this data to determine the control area frequency bias.

4.6 Voltage Monitoring

The control area operator must monitor voltage levels, and take appropriate actions to support the bulk electric system voltage if real-time trends are indicative of potential developing problems. Voltage measuring points must be of sufficient number and from several locations and voltage levels to allow the control area operator to effectively monitor the voltage profile of their control area.

Audit Notes:
With voltage monitoring equipment at almost all transmission substations, LGEE has an adequate number of voltage points. LGEE developed a voltage display for the entire control area, giving operators a good geographic display of the voltage profile.

Concerning Mvar output at maximum loading: LGEE tested the former Kentucky Utility units in the early 90s and tested the former Louisville Gas and Electric units over the past several years.

LGEE operates its system to maintain 90% of normal voltage after the first contingency. This normally results in voltages above 95% of normal. Since LGEE does not run real time contingency analyses, the first contingency voltage levels are determined from studies. MISO may be monitoring voltages with its real-time contingency analysis, but the responsibilities between MISO and LGEE were not well documented.

4.7 Reactive Reserve

The control area must ensure that reactive reserves are available and properly located to satisfy the most severe single contingency.

Audit Notes:
LGEE monitors dynamic reactive reserves for the entire control area and static reactive reserves by five regions within the control area. The team was impressed with the regional static monitoring. An EMS display shows voltages, generator reactive reserves, and total reactive capacity for each plant.

LGEE switches capacitor banks to maintain adequate dynamic reserves. The team believes that the LGEE system has adequate reactive capacity for voltage support.

LGEE voltage schedules vary by system load and are well documented. These schedules are developed for each generation plant from planning studies. The generators not owned by LGEE also have voltage schedules and reactive requirements as outlined in the contract referenced below as an example:

The Interconnection and Operating Agreement Bluegrass Generation Company, L.L.C. Paragraph 8.3, "Voltage Operating Range" states, "The normal operating range of voltage at the Point of Interconnection shall be 1.03 to 0.97 per unit." Paragraph 8.4.1 "Ordinary Reactive Power Support" states, "The applicant will regulate reactive power output of Applicant's generators so that such output remains within a range between 10 Mvar and 10 Mvar at the Point of Interconnection." Paragraph 8.4.3 "Emergency Reactive Power Support at the Request of LGEE/KU" states, "LGEE/KU has the authority to request applicant to redispatch the Mvar output of the generating units of the applicant facilities."

The LGEE reactive control policy is outlined in the Voltage Control section in NERC Policy 2, Transmission Operation, Transmission Security binder. It states that voltage guidelines have been established for specific transmission buses as a function of system load. As system load increases, voltage must be increased to the specified ranges.

	Applicable Documents	Dated	Version
1	Interconnection and Operating Agreement Bluegrass Generation Company	04/12/01	
2	Transmission Security Binder		

4.8 Critical Facility Monitoring

Monitoring facilities that are critical to the reliability of the bulk electric system is a joint responsibility of the control area operators and reliability coordinators.

There must be an established process to determine which facilities will be considered critical to the reliability of the bulk electric system, and real-time operating information (data and status). Operating limits for the critical facilities must be provided to the Control Area Operators and the Reliability Coordinators.

Audit Notes:

With the close proximity to the 765 kV system, conditions in the LGEE control area do not impact the Eastern Interconnection in a way that would results in an Interconnection Reliability Limit (IRL). LGEE does have a critical facilities list, which is documented in the Transmission Security Binder as the two-page 'Critical Facilities List.' LGEE runs the static Outage Transfer Distribution Factor (OTDF) analysis on these limits and updates MISO on these limits through the Inter-control Center Communication Protocol (ICCP). MISO also has the list of critical facilities. The LGEE critical facilities list is not contained in an EMS display.

	Applicable Documents	Dated	Version
1	Transmission Security Binder		

4.9 Transmission System Congestion

The control area must monitor transmission flowgates and be prepared to take actions to alleviate congestion in conjunction with and as directed by its reliability coordinator.

Audit Notes:

MISO is primarily responsible for congestion management for the LGEE system. MISO runs the real-time contingency analysis, calls Transmission Loading Relief (TLR)s to reduce flows on congested flowgates, calculates ATCs, and approves transmission requests based on ATCs.

MISO and LGEE have different views of the electric system; LGEE looks at its area in greater detail, while MISO focuses on a wider view. LGEE believes these approaches compliment each other, allowing MISO and LGEE to proactively coordinate activities to prevent loading problems and to reactively resolve high loads. (See planning section of report.)

LGEE sets flowgate limit alarms at 90% and 95% of continuous post-contingency loading. At 90%, operators get an alarm and inform MISO that a TLR Level 1 should be called; at 95%, they request a TLR Level 3. Since MISO has a more accurate model, MISO operators may suggest they wait before calling the TLR. Sometimes MISO discovers the high loading first from the MISO contingency analysis and suggests calling the TLR. Since LGEE sends line limits to MISO through the ICCP connection, both MISO and LGEE use the same limits.

Every hour, LGEE uses the MISO scheduling system to verify schedules. LGEE does not verify schedules with interconnected neighbors since the operators use the MISO system. LGEE does check out meter readings with its interconnected neighbors at each tie point daily. All transactions are tagged and entered in the MISO scheduler, except for reserve sharing transactions, which are entered into the MISO system after the fact.

4.10 Load Generation Balance

The control area operators must monitor the balance of load, generation, and net schedule interchange in their control area. The control area operator must take actions to mitigate unacceptable load, generation, and net scheduled interchange imbalance.

Audit Notes:

LGEE has a standard AGC package on each EMS. It uses a standard load forecasting program to ensure that it has adequate capacity to meet requirements. LGEE meets CPS and DCS requirements. The marketing group, which is separate from transmission operations and generation, is responsible for balancing load.

The generation control group is under the LGEE marketing but has a high priority on reliability and their first responsibility is to meet control area load requirements.

LGEE has agreements with generators in the control area to assist in meeting control area requirements. Interconnection and Operating Agreement Bluegrass Generation Company, L.L.C. Paragraph 8.10.1, 'Emergency redispatch' states, "Applicant's operator shall...place the levels of energy capable of being generated by such units within the exclusive control of LGEE/KU for the duration of such system emergency."

	Applicable Documents	Dated	Version
1	Interconnection and Operating Agreement Bluegrass Generation Company	04/12/01	

4.11 Contingency Reserves

The control area operator must monitor the required reserves, and the actual operating reserves in real-time, and must take action to restore acceptable reserve levels when reserve shortages are identified.

Audit Notes:

LGEE belongs to the ECAR reserve-sharing group, which consistently meets DCS requirements.

System reserves are calculated by the EMSs based on unloaded capacity, ramp rate limits from each available unit, and interruptible load information. A visual flag signifies when the reserve requirements are not satisfied, however, the EMS does not produce an audible alarm.

Meeting reserve requirements is the responsibility of the generation dispatch group and part of the generation dispatch group's personnel performance evaluations is based on how well they met reserve requirements.

4.12 Special Protection Systems

The control area operator and the reliability coordinator must be aware of the operational condition of special protection systems that may have an effect on the operation of the bulk electric system.

Audit Notes:

LGEE does not have any special protection systems.

5. System Restoration

The control area operator must have a documented system restoration plan and must provide that plan to the reliability coordinator.

The control area operator must be prepared to restore their control area following a partial or total collapse of the system and coordinate system restoration with their neighboring control areas and with the reliability coordinators.

Audit Notes:

LGEE has a system restoration plan that is documented in the emergency procedures detailing the step-by-step procedure for routing start-up power to each power plant in the event of a system blackout.

The restoration plan has a map showing the location of all the ECAR blackstart units. It lists the plants and the control area location. A separate transmission map shows the blackstart unit interconnections with the transmission system. A table shows the size of the units, and starting method along with other information including:

- Location
- Owner
- Operator
- Capacity
- Fuel type
- Type of unit
- Latest test data
- Starting method

A second procedure is in the binder titled 'NERC Policy 6, Emergency Operations and Preparation of Restoration Plan' has a tab labeled 'Appendix A1,' LG&E Company Blackstart Guidelines. These guidelines describe isolating generator buses, starting black start generators, restarting units, restoring load, stabilizing the system, and resynchronizing with the interconnected system. It also lists internal and neighboring synchronization points. This document contains:

- LGE Restoration Policy
- Emergency Contact list
- Emergency Telecommunication Plan
- Blackstart unit testing assessment
- Critical load pickup

There is a third procedure for Kentucky Utilities system restoration.

The LGEE documentation seemed complete but was divided into three books, one for each of the two control centers and a third book with other parts of the plan. The documentation did not seem to be as well organized.

LGEE does a tabletop black start drill with each operator semi-annually. In 1974, the operators actually used the system restoration plan. In 1997, they did a drill, going so far as starting the auxiliary equipment at a power plant. In 2004, the group leaders from each control center participated in a two-day drill with MISO but LGEE operators did not participate due to schedule constraints.

	Applicable Documents	Dated	Version
1	Emergency Procedures	04/2004	
2	Emergency Operations and Preparation of Restoration Plan	10/16/2004	

6. Delegation of Reliability Authority Functions

Any reliability coordinator functions that have been delegated to a control area operator must be clearly documented. The documentation must recognize that the reliability coordinator continues to be responsible for that function.

Audit Notes:
MISO does not delegate any reliability functions to LGEE.

7. Outage Coordination

Planned control area transmission facilities and generating unit outages must be coordinated with the reliability coordinator to ensure that conflicting outages do not jeopardize the reliability of the bulk electric system.

Information relative to forced outages of transmission facilities and generating units (that may jeopardize the reliability of the bulk electric system) must be shared with affected transmission operators and the control area's reliability coordinator as expeditiously as possible.

Audit Notes:
MISO and LGEE both have outage scheduler systems. All outages are entered intothe MISO outage scheduler; the LGEE outage scheduler sends outages to the MISO system. MISO and LGEE require two weeks notice for planned outages to perform system studies to determine the effects of the requested outage on the system. The MISO scheduling system allows other affected parties and the MISO reliability coordinator to review the outage schedules.

LGEE operations personnel did not provide the MISO and LGEE outage procedures documents upon request.

LGEE calls the neighboring systems one week prior to an outage affecting that system. Recently, prior to a scheduled outage, LGEE called Cinergy but found that Cinergy was unaware of the outage. Since the outage would have caused problems on the Cinergy system, LGEE delayed the outage.

LGEE has outage notification requirements in its connection contracts. The Interconnection and Operating Agreement Bluegrass Generation Company, L.L.C. covers notification in Article X, Communications, which outlines communication and coordination requirements. The Interconnection and Operating Agreement Cannelton Hydroelectric Project, L.P. covers communications requirements in Sections 4.8, Scheduling.

	Applicable Documents	Dated	Version
1	Interconnection and Operating Agreement Bluegrass Generation Company	04/12/01	
2	Interconnection and Operating Agreement Cannelton Hydroelectric Project	12/03/03	

8. Transmission and Generation Relaying

Control areas must ensure that transmission and generator relay maintenance is carried out as per control area, regional, and/or NERC established requirements.

Audit Notes:
LGEE uses three types of relays; most are electromechanical with some microprocessor based and a few solid-state relays on Extra High Voltage (EHV) lines. (EHV lines that have these relays have full relay redundancy.) Microprocessors relays have self-diagnostics and will trigger a warning light to indicate a problem. Since qualified personnel inspect substations every month, they report the alarmed relays. Repairs or further investigations are made immediately.

Relay data is collected from the relay microprocessors and analyzed each week by the planning staff. LGEE performs testing of all electromechanical relays on a five-year cycle.

Generator relay maintenance is performed during each major generator outage, generally on seven-year cycles.

The transmission and generation relaying requirements are covered in the connection agreements for the LGEE transmission system as outlined in the examples below:

Interconnection and Operating Agreement Bluegrass Generation Company, L.L.C., Paragraph 8.3, 'Protective Relays' specifies that the Applicant will operate protective relays "in compliance with LG&E/KU approved settings."

Interconnection and Operating Agreement Cannelton Hydroelectric Project, L.P. covers generator and relay requirements in Sections 4.11.3, Transmission Provider and Transmission Owner Right to Inspect. This section, for protective equipment, gives LGEE the right "to observe Generator's tests", "review settings" and "review Generators maintenance records relative to the facility."

During maintenance work, it is LGEE's practice to disable the relay protection for a few minutes while the line remains in service.

LGEE operators state that they have not had problems with relay misoperations or failures. Protection outages must be scheduled and approved by the operator.

LGEE has adequate fault recorders to monitor relay operation. To comply with ECAR requirements, LGEE installed fault recorders to provide the necessary coverage to recover fault data for 200 kV and above lines. Most fault recorders are in the Louisville area. It has many types of fault recorders including paper and digital recorders.

	Applicable Documents	Dated	Version
1	Interconnection and Operating Agreement Bluegrass Generation Company	04/12/01	
2	Interconnection and Operating Agreement Cannelton Hydroelectric Project	12/03/03	

9. Capacity and Energy Emergency Plan

Each control area must have a capacity and energy emergency plan that addresses the following functions. (It should be noted that some of the items might not be applicable, as the responsibilities for the item may not rest with the entity being reviewed.)

LGEE provided the Team with its "Emergency Procedures Manual" from the operators' floor. It contains separate documents brought together in one binder. Actions taken for the control areas' capacity and energy emergencies are outlined under the tab titled Part 2/Short Term B, Anticipated. This document is not dated. Sections of the manual or other reference material covering the capacity and energy emergency plans are indicated below (with quotations from the section showing the material covered), in the appropriate sections:

1. **Coordinating functions.** The functions to be coordinated with and among neighboring systems. (The plan should include references to coordination of actions among neighboring systems when the plans are implemented.)

   Paragraph 1 'Coordination of Functions' states the system operator is responsible for coordinating with neighboring systems and MISO.

2. **Fuel supply.** An adequate fuel supply and inventory plan, which recognizes reasonable delays or problems in the delivery or production of fuel, fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil, and a plan to optimize all generating sources to optimize the availability of the fuel, if fuel is in short supply.

   Paragraph 2 'Fuel Supply Inventory' outlines LGEE's 50-day fuel supply policy and the fuel switching plans for the combustion turbines. The fuels department is involved in a daily status meeting with marketing and generation control and provides a daily fuel supply status.

   Emergency Procedures, Part II, 'Long Term Capacity and Fuel Shortages' "provide[s] a plan for reducing the consumption of electric energy on the Kentucky Utilities Company (Company) system in the event of a severe coal shortage." It contains procedures to address declining fuel inventories that depend on the number of days left in the supply.

3. **Environmental constraints.** Plans to seek removal of environmental constraints for generating units and plants.

   Paragraph 3, 'Environmental Constraints,' states that Environmental Constraints will be removed "with approval of higher company officials in the control area."

4. **System energy use.** The reduction of the systems own energy use to a minimum.

   Paragraph 4, 'System Energy Use, states, "If time allows, the Director of Transmission will seek permission from executive management to appeal to intercompany officials to reduce intra-company energy usage as much as possible…"

5. **Public appeals.** Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

Paragraph 5, 'Public Appeals,' states, "If time allows, the Director of Transmission (or designee) will seek permission from executive management and ask corporate communications to appeal to the general public for voluntary reductions in energy use."

6. **Load management.** Implementation of load management and voltage reductions.

   Paragraph 6, 'Load Management,' states, "If necessary the Manager of Control Centers will seek approval from the Director of Transmission (or designee) Affairs to reduce system voltage and discontinue all sales of energy and transmission service in order to stabilize the system. Interruptible loads and curtailable customers will be asked to respond to contracted load level to aid in load stability."

   LGEE does not do transmission system voltage reduction to reduce load.

7. **Appeals to large customers.** Appeals to large industrial and commercial customers to reduce non-essential energy use and start any customer-owned backup generation.

   Paragraph 7, 'Appeals to Large Customer to use Alternate Fuels,' states the Director Transmission, through corporate Customer Services, will appeal to large industrial and commercial customers.

8. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

   Paragraph 8, 'Interruptible and Curtailable Loads,' states, "[T]he company does have interruptible loads and curtailable customers." They are listed in Appendix A1 of the Emergency Procedures Manual.

9. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

   Paragraph 9, 'Maximizing Generator Output and Availability' states, "All generation units shall be asked to come to maximum output… This request will be made through the Director Transmission affairs…"

10. **Notifying IPPs.** Notification of co-generation and independent power producers to maximize output and availability.

    Paragraph 10, 'Notifying IPPs' states, "Any appeal to have IPPs help with system load demands will be handled through the system control center…"

11. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community.

    Paragraph 11, 'Load Curtailment,' states that the procedure for load curtailment is on Appendix B1 but the Team could not find Appendix B1. The Emergency Procedures Manual has the Load Shed Guides. These are also on the EMS.

12. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented

    Emergency procedures manual documents has necessary forms to notify NERC and government agencies.

13. **Notification to Control Areas and Reliability Coordinators.** Notification should be made to other control areas and to the reliability coordinator as the steps of the emergency plan are implemented.

In an emergency situation, notification would take place as a natural part of the existing close communications between LGEE, its reliability coordinator and neighboring control areas.

Audit Notes:
The marketing group notifies the operators if it forecasts an energy shortage. The operators at Dix can provide energy for the control area for 30 minutes to one hour and the marketing group makes necessary purchases after that time. If necessary, Dix can implement load shedding.

LGE/KU Transmission System Emergency Action Levels in the Emergency Procedures Manual defines five emergency levels and provides specific criteria to identify each. Level 5 has an action statement to begin load shedding in the affected areas. LGEE does not have undervoltage load shedding. It does have EMS displays for manual load shedding. The system operator through the EMS can do manual load shedding.

	Applicable Documents	Dated	Version
1	Emergency Procedures Manual		
2	LGE/KU Transmission System Emergency Action Levels	06/14/00	

10. Operating Policy/Procedure Changes

Control areas must have an established procedure to ensure that control area operators and operations staff are aware of any changes to NERC, regional and/or local policies or procedures prior to taking over control of a shift position.

Control areas must have shift change procedures for updating incoming shift personnel on the current status of the system.

Audit Notes:
To update operators on policy and procedures changes, LGEE sends emails and requires the recipients to reply to indicate they received it. The replies are not logged to verify that all operators have read them and there is no formal follow up to verify that the operators understand the changes.

The operators feel that this procedure works well.

LGEE provided the team with a copy of its Emergencies Procedures Manual. It contains a section entitled 'Informational Passage Procedure.' Section I contains procedures to pass information to the next shift and Section II contains procedure to pass along NERC and ECAR policy revisions. This section was not dated.

While LGEE has a procedure to update incoming shift personnel, the operators were not aware of it. LGEE does not have a check-off sheet to document transfer of necessary information and to help operators make sure the necessary information has been transferred.

	Applicable Documents	**Dated**	**Version**
1	Emergencies Procedures Manual		

11. Vegetation Management (Line Clearances)

Control areas must have a documented Vegetation Management Program.

Audit Notes:
Three times per year, LGEE uses aerial patrols to check its transmission lines and rights-of-way. The patrols take care to look for new building starts that are more prevalent in the spring and usually on the 69 kV system.

The right-of-way clearing is done on a six-year cycle. LGEE personnel were very adamant that they do not trim the transmission rights-of-way; they clear them. LGEE has a good relationship with the state and other governmental bodies, which understand the need for vegetation management and its effect on reliability. LGEE has not reduced the tree-trimming budget for transmission right-of-way even though other budgets have been trimmed.

The operators could not recall any incidents where vegetation came in contact with a transmission line.

The Kentucky Utilities and ODP Transmission Policies and Procedures, Section 400, Transmission Vegetation Management Program, policy is to always clear the area under transmission lines. This policy details the clearing policy and minimum clearance. "The LGEE Energy Transmission System, in order to assure safe and adequate operation of its transmission system and as part of the Transmission Vegetation Management Program, shall completely inspect its right-of-way at intervals not to exceed one year."

LGEE's tree-trimming plan is well documented and the documentation is organized and clear.

	Applicable Documents	Dated	Version
1	Kentucky Utilities and ODP Transmission Policies and Procedures	01/01/04	

12. Nuclear Power Plant Requirements
Nuclear power plants have regulatory requirement for voltage and power in both normal and abnormal operating conditions (N-1 and system restoration).

Audit Notes:
LGEE has no nuclear power plant on its system. There are no nuclear power plants on neighboring systems that need support from LGEE.

Conclusions

Positive findings:

- Vegetation Management

LGEE clears its transmission rights-of-way. It has a well-documented inspection program and maintenance schedule. It works closely with governmental agencies that understand the needs of the utility. The right-of-way management program is well documented in LGEE Policy and Procedures and is adequately funded. LGEE Vegetation Management is a "Best Practice."

- Two Facilities

LGEE was created with the merger of Louisville Gas and Electric and Kentucky Utilities. LGEE decided to maintain both control centers and both EMS systems. It is in the process of dual porting RTUs at all the tie points, all generation, and other significant facilities. It is providing diversely routed communication paths from the RTU to each control center. When the project is completed, LGEE will essentially have two independent operating control centers, each acting as an operating back up of the other. When these changes are completed, the control center backup could be a "best practice."

- Alarm System Monitoring

LGEE monitors the alarms so that if the alarms are inactive for a period of time, the operators are notified.

- Reactive Reserve Monitoring by Regions

The LGEE EMSs monitors the static reactive sources by region such that the operator can see resources used and resources available on one display. Since voltage support is location dependant, this display is very beneficial.

- Good use of Voltage Schedules

LGEE has well-documented voltage schedules on important busses. The schedules have the necessary voltages by load as determined by their planning studies. It has determined necessary generation configurations needed to support voltage and orders combustion turbines online when needed according to these schedules.

- Knowledgeable and Certified Operators

The LGEE operators and their supervisors are knowledgeable and all are certified at the reliability coordinator level. All positions that the Team thought should be certified were certified. Operators are not allowed to independently operate the system until they pass the certification exam and demonstrate mastery of the skills necessary to operate the system.

- The training group keeps good records for each operator in the training book

LGEE keeps a book on each operator with the information demonstrating that that operator is ready to perform his/her duties. The book includes the NERC certification certificate, annual function reviews that verify that the trainer has reviewed the operator's job knowledge, and critical operating information that the operator has reviewed.

- Operators have functional control of operating system maintenance

The support staff for the EMS reports to the operational management, allowing operations personnel to prioritizes work and repairs. The Team supports this organizational structure.

The communications system personnel report to corporate information systems. The operators have call-out lists and can determine whether to go through organizational channels or call-out the support directly. LGEE has good support, coordination, and cooperation between operations and information technology and the Team commends LGEE for this.

- Good cyber security practices

The Team is satisfied with their Cyber Security Policy and feels the network structure provides good cyber security protection.

- Emergency Procedure Documentation

LGEE has a well thought out emergency procedure, with unique procedures for islanding generation with load to attempt to keep generation online.

MSJ Rebuttal Exhibit 3 – November 1, 2004 Letter

Midwest ISO
We manage power.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

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November 1, 2004

Mr. Victor A. Staffieri
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LG&E Energy, LLC
220 West Main Street
Louisville, KY 40202

Dear Vic:

As a follow-up to our discussion at the September EEI Midwest CEO meeting in Colorado Springs, CO, the Midwest ISO has reviewed your company's Market Participant and Control Area readiness for participation in the Midwest Energy Markets scheduled to begin in March of next year. Market Participant readiness will most assuredly help make for a smooth transition to the new market structure; therefore, I encourage your continued cooperation and participation in our market implementation programs. The purpose of this letter is to inform you of your company's current level of participation and readiness.

Market Participant Readiness

The Midwest ISO has identified four areas where your participation has been necessary to prepare your company for successful market start. The specific activities and objectives that comprise each area are described below:

> **Registration**—Market Participant Applicant has submitted all applicable data requested in the Market Participant Application, including executable documents; attended training on market topics offered by the Midwest ISO; participated in market trials as preparation for market launch; undergone qualification testing; and has registered its assets and submitted the "Asset Confirmation Sheet."
>
> **Creditworthiness**—Market Participant Applicant has an approved credit limit and has made the necessary allocation to the Virtual Market and/or the Financial Transmission Rights (FTR) Market in order to participate in either market.
>
> **Training**—Comprehensive training courses (ranging from introductory to advanced) were offered prior to the start of Day in the Life Enhanced (DILE) demonstrations and included: Midwest Market 101 and 102, Market Settlements Workshop 101, 201, and 301, Bids and Offers 201, Financial Transmission Rights 201, Physical and Financial Scheduling 201, Market Scenarios Workshop 301, and Market Data Management Agent.

Day in the Life Enhanced (DILE)—These demonstrations allowed for a scripted interchange that starts with bids followed by calculating and forwarding of invoices that result in payment – essentially a trial run that included the billing and settlement of energy transactions and transmission service. During the demonstrations, specific information was made available in the areas of Day-Ahead and Real-Time Operations; Financial Transmission Rights (FTRs); Physical Scheduling; Market Monitoring; Credit; and Invoicing.

We have reviewed your company's progress in each of these areas. As far as creditworthiness, registration and training are concerned, your company satisfied the objectives and to date your company representatives have successfully completed one hundred-six (106) sessions of Midwest ISO training.

For Day in the Life Enhanced (DILE) demonstrations, we evaluated your company's participation based on the percentage of available scripted functions that were performed by your representatives during the four-week period of operation. High, medium and low participation designations were then assigned—zero to 30% being low, 31 to 60% being medium and 61 to 100% being high. The participation of your company fell within the high range. This is a desirable level of participation and I encourage that this level of activity be supported and maintained.

Control Area Readiness

The Midwest ISO has also identified four areas where your completion of testing and participation has been necessary to ensure control area readiness prior to market start. The specific activities that comprise each area are described below:

Open Loop Testing—A check between a control area and the Midwest ISO to verify that the communication links are correctly configured, operational, and that the control area has reconfigured its EMS (Emergency Management System) to correctly interrupt and respond to NSI (Net Scheduled Interchange) directions sent from MISO.

Closed Loop Testing—A continuation of EMS configuration, wherein instructions are sent to the control area that vary the base points of two separate generating units to verify that they respond in the correct direction at the designated times.

ICCP (Inter-control Center Communications Protocol) **Testing** —A computer protocol developed for the electric industry to allow for efficient transfer of real-time data for operational control.

XML (Extensible Markup Language) **Testing**—A commonly used file form that allows messages and data to be efficiently transferred.

Each of the above testing procedures was successfully completed for your company. A substantial amount of coordination and cooperation was necessary to accomplish these results and we look forward to a continuing successful working relationship.

Recently, Market Participants and the Midwest ISO successfully completed Day in the Life market trials, which represent a "major step forward" in our own preparation for the launch of the Midwest Energy Markets. The next step in our preparation for operating the Midwest Energy Markets will be parallel operations – a continuation of the Day in the Life interchange that allows for *unscripted* interactions between market participants under a variety of market conditions. Parallel operations will utilize real-time production feeds that implement the Midwest ISO's internal processes on a 24-hour basis. We will also initiate the actual Financial Transmission Rights (FTR) allocation process during this same timeframe.

Parallel Operations will be run in two distinct phases. Parallel Operations I will run from November 8 to December 17. Parallel Operations II will run from January 3 to February 1 and will include more enhanced testing that will incorporate Grandfathered Agreement (GFA) enhancements and the final Energy Market Tariff changes required by FERC. These simulations will be a true test of market preparedness; therefore, I encourage your company's participation in Parallel Operations.

A Midwest ISO executive has already or will be contacting soon your designated "Executive Sponsor" for market readiness. Please let us know if your company has any additional needs or concerns at that time. I look forward to working together to bring about a successful Energy Market that will benefit consumers throughout the Midwest.

Sincerely,

James P. Torgerson
President and CEO
Midwest ISO

cc: Mark Johnson

VERIFICATION

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

The undersigned, **Mark S. Johnson**, being duly sworn, deposes and says he is Director of Transmission for LG&E Energy Services Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Mark S. Johnson

MARK S. JOHNSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of January 2005.

Tammy J. Elzy

Notary Public

My Commission Expires:

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