MODULE E - RESOURCE ADEQUACY

I. INTRODUCTION

This Module E provides requirements and standards to be met by the Transmission Provider and Market Participants to ensure access to adequate Generation Resources to meet demand on the Transmission System. The resource adequacy requirements established in this Module E are based upon the pre-existing reliability mechanisms of the states within the Transmission Provider Region and within the Regional Reliability Organizations (RRO), as adapted to the Transmission Provider Region.

II. RESOURCE ADEQUACY REQUIREMENTS

68 Compliance with Existing State and Reliability Resource Organization Requirements

68.1 Market Participant Responsibilities

68.1.1 Compliance with Regional Reliability Organizations

a. A Market Participant serving Load within the Transmission Provider Region must comply with all requirements, including those related to operating and planning reserves, of the appropriate RRO governing the location(s) where the Market Participant's Load is located.

b. To the extent that a Market Participant serves Load outside of the Transmission Provider Region, this Module E does not impose upon the Market Participant any obligation to

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conform to RRO standards for that *pro rata* portion of Load that is not located in the Transmission Provider Region.

c. To the extent that a Market Participant serves Load within two (2) or more RRO regions within the Transmission Provider Region, the Market Participant must comply with each applicable RRO's requirements for the *pro rata* portion of the Load served within each RRO region within the Transmission Provider Region.

d. Market Participants serving Load in the Transmission Provider Region that are currently members of Reserve Sharing Groups may not withdraw from such groups without the prior approval of the Transmission Provider.

e. Market Participants will identify to the Transmission Provider those Resources relied upon to comply with RRO reliability and resource adequacy standards, including operating and planning reserve standards. Resource identification will occur on an annual basis, or more frequently where required by RRO standards, according to procedures set forth in the Business Practices Manuals.

68.1.2 Compliance with State Authorities

a. Market Participants that serve Load within the Transmission Provider Region must comply with all regulations and laws regarding reliability, including any reserve margin requirements, of the states in which the Transmission Provider operates.

b. To the extent that a Market Participant serves Load in two (2) or more states in the Transmission Provider Region, the Market Participant must comply with the reliability or resource adequacy requirements of each state in which it serves Load.

c. Market Participants will identify to the Transmission Provider those Resources relied upon to comply with State resource adequacy standards, as determined by the Transmission Provider. Such identification will occur on an annual basis, or more frequently where required by state standards, according to procedures set forth in the Business Practices Manuals.

68.1.3 Contracts Supporting Reliability Obligations.

A Market Participant may contract with other entities to ensure compliance with an RRO's or state's reliability obligations, consistent with any RRO or state requirements for, or limitations related to, such contracts.

68.2 Transmission Provider Requirements

68.2.1 Determination of Compliance by the Transmission Provider

a. The Transmission Provider will determine reliability and resource adequacy standards, including operating and planning reserve standards, applicable to Load served within the Transmission Provider Region. The Transmission Provider shall notify Market Participants of the reliability and resource adequacy obligations determined to be applicable to Load in each state.

i. Determination of reliability and resource adequacy standards shall be based to the extent feasible on existing RRO and state standards.

ii. The Transmission Provider shall work with individual state policymakers, state regulatory agencies, the Organization of Midwest ISO States and RROs to resolve inconsistencies between state and RRO resource adequacy requirements and their application to Market Participants.

iii. If there is an irreconcilable difference between the reliability or resource adequacy obligations of an applicable RRO (or RROs) and a state (or states), the Transmission Provider shall determine standards that comply fully with the obligations imposed by the state(s) while complying with such portion of the RROs' requirements as is feasible.

iv. If the Transmission Provider is unable to determine that an adequacy standard is in effect for Load within a state within the Transmission Provider Region, an annual reserve margin requirement of twelve (12) percent will be applied to Load in that state.

b. The Transmission Provider shall review compliance by Market Participants with the reliability and resource adequacy requirements determined by the Transmission Provider to apply to Load in each state.

i. The Transmission Provider will conduct its review of reliability and resource adequacy compliance in conformance with the applicable state or RRO timeframe, but no less often than annually.

ii. To the extent feasible, the Transmission Provider will utilize RRO or state compliance policies (*e.g.*, adjustments for forced outage rates, treatment of imports, etc.) to evaluate compliance by Market Participants subject to applicable RRO or state obligations.

68.2.2 Qualification of Resources

The Transmission Provider shall determine criteria for Resources to qualify as satisfying RRO and state reliability requirements.

a. The Transmission Provider shall work with individual state policymakers, state regulatory agencies, the Organization of Midwest ISO States and RROs to determine applicable criteria and to resolve inconsistencies between state and RRO criteria.

b. If there is an irreconcilable difference between the criteria of an applicable RRO (or RROs) and a state (or states), the Transmission Provider shall determine criteria that comply fully with those imposed by the state(s) while complying with such portion of the RROs' criteria as is feasible.

c. If the Transmission Provider is unable to determine criteria applicable to Load within a state, the Transmission Provider will establish such criteria for purpose of assessing compliance with applicable resource adequacy standards consistent NERC standards, good utility practice, and criteria in place in other RROs and states within the Transmission Provider Region.

69 Designated Network Resources

69.1 Designation of Designated Network Resources

Resources identified by Market Participants as available to meet the reliability requirements determined by the Transmission Provider must comply with the requirements for specification as Designated Network Resources (DNRs) consistent with the procedures set forth by the Transmission Provider. Exceptions to this requirement will be made by the Transmission Provider for demand reductions and behind-the-meter generation Resources to the extent that such

Resources are designated as Alternative Capacity Resources, as described in Section 70.

69.1.1 Single State or RRO DNRs

If a Market Participant serves Load both in the Transmission Provider Region and outside the Transmission Provider Region within a single state or RRO region, then the Market Participant must specify DNRs in the proportion of its Load in the Transmission Provider Region within the state or RRO to its total Load within the state or RRO region.

69.1.2 DNR Requirements

a. Specification of a DNR will require ownership or equivalent contractual rights that assure that each DNR complies with all applicable requirements specified in this Module E. Market Participants may satisfy this obligation by fulfilling either of the following requirements:

i. Specifying a DNR Generation Resource registered with the Transmission Provider by the Market Participant; or

ii. Specifying as a DNR a Generation Resource registered with the Transmission Provider by another Market Participant and providing proof, as required by the Transmission Provider, that the Generation Owner accepts specification as a DNR and the responsibility to comply with all applicable requirements of such designation.

b. Generation Resources designated as DNRs must be deliverable to Load within the Transmission Provider Region. To ensure deliverability, Network Customers shall be required to make a request for Network Integration Transmission Service for new DNRs. The deliverability of DNRs to Network Load within the Transmission Provider Region shall be determined by System Impact Studies pursuant to this Tariff as conducted by the Transmission Provider that considers, among other factors, the delivery of aggregate Resources of Network Customers to the aggregate of Network Load. The System Impact Study will include validation that a new DNR can be dispatched along with all other DNRs specified by Network Customers in the vicinity of the newly designated Generation Resource. If the Generation Resource designated as a DNR is a Generation Resource that received Network Resource Interconnection Service to the Network Customer requesting the new designation, the DNR deliverability study that was performed during the interconnection process shall serve to suffice for the System Impact Study required in this subsection, unless at the sole discretion of the Transmission Provider the System Impact Study performed during the interconnection process study is insufficient for this purpose.

69.1.3 Determination of Compliance with Designated Network Resource Requirements

The Transmission Provider shall be responsible for determining whether Market Participants have appropriately assigned DNRs pursuant this Module E. The Transmission Provider may, at its sole discretion, determine that it is appropriate to allow a grace period for full compliance with the DNR requirements of this Module E. It is also within the Transmission Provider's discretion to allow all Market Participants reasonable time to modify contract terms to comply with the new requirements of this Module E. Any such grace period will be announced to all Market Participants.

69.2 DNR Must Offer Requirement

DNRs must submit a Self-Schedule or offer in the Day-Ahead Energy Market and the first Reliability Assessment Commitment, except to the extent that the DNR is unavailable due to a full or partial forced or scheduled outage consistent with this Tariff. Capacity reserved for use as Regulation, Spinning Reserve or Non-Spinning Reserve, consistent with the terms of Module C, will be deemed to have satisfied the requirement to Self-Schedule or offer in the Day-Ahead Energy Market. At its sole discretion, Transmission Provider may curtail export transaction schedules sourced at a DNR or from the Spot Market during a declared Energy Emergency Alert. Procedures for such curtailments shall be specified in the Business Practices Manuals. The Transmission Provider may not curtail export transactions for generation resources responding to a reserve activation in accordance with the terms and conditions of a Regional Reserve Sharing Agreement during the time such reserve activation is effective.

70 Alternative Capacity Resource

70.1 Qualifying Resources

The following Resources will be designated as Alternative Capacity Resources, notwithstanding the fact that such Resources may fail to meet the criteria to be designated as a DNR, if the Resources satisfy criteria to be counted toward state or RRO resource adequacy standards.

70.1.1 Interruptible Demand

Market Participants with demand that is interruptible on an economic or emergency basis and that has been identified as satisfying applicable state or RRO standards, as determined by the Transmission Provider, shall provide information, including the location(s), quantity, price, required emergency conditions, and any other information deemed necessary by the Transmission Provider in order to determine the circumstances under which the demand reduction may be instructed by the Transmission Provider. The Market Participant will implement demand reductions when instructed by the Transmission Provider.

70.1.2 Behind the Meter Generation

Market Participants that own or control behind-the-meter generation that has been identified as satisfying state or RRO adequacy standards, as determined by the Transmission Provider, provide information, including the location(s), MW, any operating restrictions, and any other information deemed necessary by the Transmission Provider in order to determine the circumstances under which the resource may be called upon to generate. The Market Participant shall notify the Transmission Provider of the status and availability of the unit on a daily basis according to procedures specified in the Business Practices Manuals. The Market Participant will commit and dispatch the unit when instructed by the Transmission Provider.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
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August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts
February 10, 2004

Preamble

The Board of Trustees recognizes the paramount importance of a reliable bulk electric system in North America. In consideration of the findings of the investigation into the August 14, 2003 blackout, NERC must take firm and immediate actions to increase public confidence that the reliability of the North American bulk electric system is being protected.

A key finding of the blackout investigators is that violations of existing NERC reliability standards contributed directly to the blackout. Pending enactment of federal reliability legislation creating a framework for enforcement of mandatory reliability standards, and with the encouragement of the Stakeholders Committee, the board is determined to obtain full compliance with all existing and future reliability standards and intends to use all legitimate means available to achieve that end. The board therefore resolves to:

- *Receive specific information on all violations of NERC standards, including the identities of the parties involved;*
- *Take firm actions to improve compliance with NERC reliability standards;*
- *Provide greater transparency to violations of standards, while respecting the confidential nature of some information and the need for a fair and deliberate due process; and*
- *Inform and work closely with the Federal Energy Regulatory Commission and other applicable federal, state, and provincial regulatory authorities in the United States, Canada, and Mexico as needed to ensure public interests are met with respect to compliance with reliability standards.*

The board expresses its appreciation to the blackout investigators and the Steering Group for their objective and thorough work in preparing a report of recommended NERC actions. With a few clarifications, the board approves the report and directs implementation of the recommended actions. The board holds the assigned committees and organizations accountable to report to the board the progress in completing the recommended actions, and intends itself to publicly report those results. The board recognizes the possibility that this action plan may have to be adapted as additional analysis is completed, but stresses the need to move forward immediately with the actions as stated.

Staff Exhibit 2 - Falk witness

Furthermore, the board directs management to immediately advise the board of any significant violations of NERC reliability standards, including details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Management shall supply to the board in advance of board meetings a detailed report of all violations of reliability standards.

Finally, the board resolves to form a task force to develop guidelines for the board to consider with regard to the confidentiality of compliance information and disclosure of such information to regulatory authorities and the public.

Overview of Investigation Conclusions

The North American Electric Reliability Council (NERC) has conducted a comprehensive investigation of the August 14, 2003 blackout. The results of NERC's investigation contributed significantly to the U.S./Canada Power System Outage Task Force's November 19, 2003 Interim Report identifying the root causes of the outage and the sequence of events leading to and during the cascading failure. NERC fully concurs with the conclusions of the Interim Report and continues to provide its support to the Task Force through ongoing technical analysis of the outage. Although an understanding of what happened and why has been resolved for most aspects of the outage, detailed analysis continues in several areas, notably dynamic simulations of the transient phases of the cascade and a final verification of the full scope of all violations of NERC and regional reliability standards that occurred leading to the outage.

From its investigation of the August 14 blackout, NERC concludes that:

- Several entities violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout.
- The existing process for monitoring and assuring compliance with NERC and regional reliability standards was shown to be inadequate to identify and resolve specific compliance violations before those violations led to a cascading blackout.
- Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.
- Problems identified in studies of prior large-scale blackouts were repeated, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions.
- In some regions, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking with actual system data and field testing.
- Planning studies, design assumptions, and facilities ratings were not consistently shared and were not subject to adequate peer review among operating entities and regions.
- Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system.

Overview of Recommendations

The Board of Trustees approves the NERC Steering Group recommendations to address these shortcomings. The recommendations fall into three categories.

Actions to Remedy Specific Deficiencies: Specific actions directed to First Energy (FE), the Midwest Independent System Operator (MISO), and the PJM Interconnection, LLC (PJM) to correct the deficiencies that led to the blackout.

1. Correct the Direct Causes of the August 14, 2003 Blackout.

Strategic Initiatives: Strategic initiatives by NERC and the 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.

2. Strengthen the NERC Compliance Enforcement Program.
3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.
4. Evaluate Vegetation Management Procedures and Results.
5. Establish a Program to Track Implementation of Recommendations.

Technical Initiatives: Technical initiatives to prevent or mitigate the impacts of future cascading blackouts.

6. Improve Operator and Reliability Coordinator Training
7. Evaluate Reactive Power and Voltage Control Practices.
8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.
10. Establish Guidelines for Real-Time Operating Tools.
11. Evaluate Lessons Learned During System Restoration.
12. Install Additional Time-Synchronized Recording Devices as Needed.
13. Reevaluate System Design, Planning and Operating Criteria.
14. Improve System Modeling Data and Data Exchange Practices.

Market Impacts

Many of the recommendations in this report have implications for electricity markets and market participants, particularly those requiring reevaluation or clarification of NERC and regional standards, policies and criteria. Implicit in these recommendations is that the NERC board charges the Market Committee with assisting in the implementation of the recommendations and interfacing with the North American Energy Standards Board with respect to any necessary business practices.

Recommendation to Remedy Specific Deficiencies

Recommendation 1. Correct the Direct Causes of the August 14, 2003 Blackout.

NERC's technical analysis of the August 14 blackout leads it to fully concur with the Task Force Interim Report regarding the direct causes of the blackout. The report stated that the principal causes of the blackout were that FE did not maintain situational awareness of conditions on its power system and did not adequately manage tree growth in its transmission rights-of-way. Contributing factors included ineffective diagnostic support provided by MISO as the reliability coordinator for FE and ineffective communications between MISO and PJM.

NERC will take immediate and firm actions to ensure that the same deficiencies that were directly causal to the August 14 blackout are corrected. These steps are necessary to assure electricity customers, regulators and others with an interest in the reliable delivery of electricity that the power system is being operated in a manner that is safe and reliable, and that the specific causes of the August 14 blackout have been identified and fixed.

Recommendation 1a: FE, MISO, and PJM shall each complete the remedial actions designated in Attachment A for their respective organizations and certify to the NERC board no later than June 30, 2004, that these specified actions have been completed. Furthermore, each organization shall present its detailed plan for completing these actions to the NERC committees for technical review on March 23-24, 2004, and to the NERC board for approval no later than April 2, 2004.

Recommendation 1b: The NERC Technical Steering Committee shall immediately assign a team of experts to assist FE, MISO, and PJM in developing plans that adequately address the issues listed in Attachment A, and other remedial actions for which each entity may seek technical assistance.

Strategic Initiatives to Assure Compliance with Reliability Standards and to Track Recommendations

Recommendation 2. Strengthen the NERC Compliance Enforcement Program.

NERC's analysis of the actions and events leading to the August 14 blackout leads it to conclude that several violations of NERC operating policies contributed directly to an uncontrolled, cascading outage on the Eastern Interconnection. NERC continues to investigate additional violations of NERC and regional reliability standards and expects to issue a final report of those violations in March 2004.

In the absence of enabling legislation in the United States and complementary actions in Canada and Mexico to authorize the creation of an electric reliability organization, NERC lacks legally sanctioned authority to enforce compliance with its reliability rules. However, the August 14 blackout is a clear signal that voluntary compliance with reliability rules is no longer adequate. NERC and the regional reliability councils must assume firm authority to measure compliance, to more transparently report significant violations that could risk the integrity of the interconnected power system, and to take immediate and effective actions to ensure that such violations are corrected.

> Violations of NERC standards identified in the November 19, 2003 Interim Report:
> 1. Following the outage of the Chamberlin-Harding 345 kV line, FE did not take the necessary actions to return the system to a safe operating state within 30 minutes (violation of NERC Operating Policy 2).
> 2. FE did not notify other systems of an impending system emergency (violation of NERC Operating Policy 5).
> 3. FE's analysis tools were not used to effectively assess system conditions (violation of NERC Operating Policy 5).
> 4. FE operator training was inadequate for maintaining reliable conditions (violation of NERC Operating Policy 8).
> 5. MISO did not notify other reliability coordinators of potential problems (violation of NERC Operating Policy 9).

Recommendation 2a: Each regional reliability council shall report to the NERC Compliance Enforcement Program within one month of occurrence all significant[1] violations of NERC operating policies and planning standards and regional standards, whether verified or still under investigation. Such reports shall confidentially note details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Additionally, each regional reliability council shall report quarterly to NERC, in a format prescribed by NERC, all violations of NERC and regional reliability council standards.

Recommendation 2b: Being presented with the results of the investigation of any significant violation, and with due consideration of the surrounding facts and circumstances, the NERC board shall require an offending organization to correct the violation within a specified time. If the board determines that an offending organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the board will seek to remedy the violation by requesting assistance of the appropriate regulatory authorities in the United States, Canada, and Mexico.

[1] Although all violations are important, a significant violation is one that could directly reduce the integrity of the interconnected power systems or otherwise cause unfavorable risk to the interconnected power systems. By contrast, a violation of a reporting or administrative requirement would not by itself generally be considered a significant violation.

Recommendation 2c: The Planning and Operating Committees, working in conjunction with the Compliance Enforcement Program, shall review and update existing approved and draft compliance templates applicable to current NERC operating policies and planning standards; and submit any revisions or new templates to the board for approval no later than March 31, 2004. To expedite this task, the NERC President shall immediately form a Compliance Template Task Force comprised of representatives of each committee. The Compliance Enforcement Program shall issue the board-approved compliance templates to the regional reliability councils for adoption into their compliance monitoring programs.

This effort will make maximum use of existing approved and draft compliance templates in order to meet the aggressive schedule. The templates are intended to include all existing NERC operating policies and planning standards but can be adapted going forward to incorporate new reliability standards as they are adopted by the NERC board for implementation in the future.

When the investigation team's final report on the August 14 violations of NERC and regional standards is available in March, it will be important to assess and understand the lapses that allowed violations to go unreported until a large-scale blackout occurred.

Recommendation 2d: The NERC Compliance Enforcement Program and ECAR shall, within three months of the issuance of the final report from the Compliance and Standards investigation team, evaluate the identified violations of NERC and regional standards, as compared to previous compliance reviews and audits for the applicable entities, and develop recommendations to improve the compliance process.

Recommendation 3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.

In conducting its investigation, NERC found that deficiencies in control area and reliability coordinator capabilities to perform assigned reliability functions contributed to the August 14 blackout. In addition to specific violations of NERC and regional standards, some reliability coordinators and control areas were deficient in the performance of their reliability functions and did not achieve a level of performance that would be considered acceptable practice in areas such as operating tools, communications, and training. In a number of cases there was a lack of clarity in the NERC policies with regard to what is expected of a reliability coordinator or control area. Although the deficiencies in the NERC policies must be addressed (see Recommendation 9), it is equally important to recognize that standards cannot prescribe all aspects of reliable operation and that minimum standards present a threshold, not a target for performance. Reliability coordinators and control areas must perform well, particularly under emergency conditions, and at all times strive for excellence in their assigned reliability functions and responsibilities.

Recommendation 3a: The NERC Compliance Enforcement Program and the regional reliability councils shall jointly establish a program to audit the reliability readiness of all reliability coordinators and control areas, with immediate attention given to addressing the deficiencies identified in the August 14 blackout investigation. Audits of all control areas and reliability coordinators shall be completed within three years and continue in a three-year cycle. The 20 highest priority audits, as determined by the Compliance Enforcement Program, will be completed by June 30, 2004.

Recommendation 3b: NERC will establish a set of baseline audit criteria to which regional criteria may be added. The control area requirements will be based on the existing NERC Control Area Certification Procedure. Reliability coordinator audits will include evaluation of reliability plans, procedures, processes, tools, personnel qualifications, and training. In addition to reviewing written documents, the audits will carefully examine the actual practices and preparedness of control areas and reliability coordinators.

Recommendation 3c: The reliability regions, with the oversight and direct participation of NERC, will audit each control area's and reliability coordinator's readiness to meet these audit criteria. FERC and other relevant regulatory agencies will be invited to participate in the audits, subject to the same confidentiality conditions as the other members of the audit teams.

Recommendation 4. Evaluate Vegetation Management Procedures and Results.

Ineffective vegetation management was a major cause of the August 14 blackout and also contributed to other historical large-scale blackouts, such on July 2-3, 1996 in the west. Maintaining transmission line rights-of-way (ROW), including maintaining safe clearances of energized lines from vegetation, under-build, and other obstructions[2] incurs a substantial ongoing cost in many areas of North America. However, it is an important investment for assuring a reliable electric system.

NERC does not presently have standards for ROW maintenance. Standards on vegetation management are particularly challenging given the great diversity of vegetation and growth patterns across North America. However, NERC's standards do require that line ratings are calculated so as to maintain safe clearances from all obstructions. Furthermore, in the United States, the National Electrical Safety Code (NESC) Rules 232, 233, and 234 detail the minimum vertical and horizontal safety clearances of overhead conductors from grounded objects and various types of obstructions. NESC Rule 218 addresses tree clearances by simply stating, "Trees that may interfere with ungrounded supply conductors should be trimmed or removed." Several states have adopted their own electrical safety codes and similar codes apply in Canada.

Recognizing that ROW maintenance requirements vary substantially depending on local conditions, NERC will focus attention initially on measuring performance as indicated by the number of high voltage line trips caused by vegetation rather than immediately move toward developing standards for

[2] Vegetation, such as the trees that caused the initial line trips in FE that led to the August 14, 2003 outage is not the only type of obstruction that can breach the safe clearance distances from energized lines. Other examples include under-build of telephone and cable TV lines, train crossings, and even nests of certain large bird species.

ROW maintenance. This approach has worked well in the Western Electricity Coordinating Council (WECC) since being instituted after the 1996 outages.

Recommendation 4a: NERC and the regional reliability councils shall jointly initiate a program to report all bulk electric system[3] transmission line trips resulting from vegetation contact[4]. The program will use the successful WECC vegetation monitoring program as a model.

Recommendation 4b: Beginning with an effective date of January 1, 2004, each transmission operator will submit an annual report of all vegetation-related high voltage line trips to its respective reliability region. Each region shall assemble a detailed annual report of vegetation-related line trips in the region to NERC no later than March 31 for the preceding year, with the first reporting to be completed by March 2005 for calendar year 2004.

Vegetation management practices, including inspection and trimming requirements, can vary significantly with geography. Additionally, some entities use advanced techniques such as planting beneficial species or applying growth retardants. Nonetheless, the events of August 14 and prior outages point to the need for independent verification that viable programs exist for ROW maintenance and that the programs are being followed.

Recommendation 4c: Each bulk electric transmission owner shall make its vegetation management procedure, and documentation of work completed, available for review and verification upon request by the applicable regional reliability council, NERC, or applicable federal, state or provincial regulatory agency.

Should this approach of monitoring vegetation-related line outages and procedures prove ineffective in reducing the number of vegetation-related line outages, NERC will consider the development of minimum line clearance standards to assure reliability.

Recommendation 5. Establish a Program to Track Implementation of Recommendations.

The August 14 blackout shared a number of contributing factors with prior large-scale blackouts, including:

- Conductors contacting trees
- Ineffective visualization of power system conditions and lack of situational awareness
- Ineffective communications
- Lack of training in recognizing and responding to emergencies
- Insufficient static and dynamic reactive power supply
- Need to improve relay protection schemes and coordination

[3] All transmission lines operating at 230 kV and higher voltage, and any other lower voltage lines designated by the regional reliability council to be critical to the reliability of the bulk electric system, shall be included in the program.
[4] A line trip includes a momentary opening and reclosing of the line, a lock out, or a combination. For reporting purposes, all vegetation-related openings of a line occurring within one 24-hour period should be considered one event. Trips known to be caused by severe weather or other natural disaster such as earthquake are excluded. Contact with vegetation includes both physical contact and arcing due to insufficient clearance.

It is important that recommendations resulting from system outages be adopted consistently by all regions and operating entities, not just those directly affected by a particular outage. Several lessons learned prior to August 14, if heeded, could have prevented the outage. WECC and NPCC, for example, have programs that could be used as models for tracking completion of recommendations. NERC and some regions have not adequately tracked completion of recommendations from prior events to ensure they were consistently implemented.

Recommendation 5a: NERC and each regional reliability council shall establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, as well as NERC and regional reports on violations of reliability standards, results of compliance audits, and lessons learned from system disturbances. Regions shall report quarterly to NERC on the status of follow-up actions to address recommendations, lessons learned, and areas noted for improvement. NERC staff shall report both NERC activities and a summary of regional activities to the board.

Assuring compliance with reliability standards, evaluating the reliability readiness of reliability coordinators and control areas, and assuring recommended actions are achieved will be effective steps in reducing the chances of future large-scale outages. However, it is important for NERC to also adopt a process for continuous learning and improvement by seeking continuous feedback on reliability performance trends, not rely mainly on learning from and reacting to catastrophic failures.

Recommendation 5b: NERC shall by January 1, 2005 establish a reliability performance monitoring function to evaluate and report bulk electric system reliability performance.

Such a function would assess large-scale outages and near misses to determine root causes and lessons learned, similar to the August 14 blackout investigation. This function would incorporate the current Disturbance Analysis Working Group and expand that work to provide more proactive feedback to the NERC board regarding reliability performance. This program would also gather and analyze reliability performance statistics to inform the board of reliability trends. This function could develop procedures and capabilities to initiate investigations in the event of future large-scale outages or disturbances. Such procedures and capabilities would be shared between NERC and the regional reliability councils for use as needed, with NERC and regional investigation roles clearly defined in advance.

Technical Initiatives to Minimize the Likelihood and Impacts of Possible Future Cascading Outages

Recommendation 6. Improve Operator and Reliability Coordinator Training.

NERC found during its investigation that some reliability coordinators and control area operators had not received adequate training in recognizing and responding to system emergencies. Most notable was the lack of realistic simulations and drills for training and verifying the capabilities of operating personnel. This training deficiency contributed to the lack of situational awareness and failure to declare an emergency when operator intervention was still possible prior to the high speed portion of the sequence of events.

Recommendation 6: All reliability coordinators, control areas, and transmission operators shall provide at least five days per year of training and drills in system emergencies, using realistic simulations[5], for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed prior to June 30, 2004, with credit given for documented training already completed since July 1, 2003. Training documents, including curriculum, training methods, and individual training records, are to be available for verification during reliability readiness audits.

NERC has published Continuing Education Criteria specifying appropriate qualifications for continuing education providers and training activities.

In the longer term, the NERC Personnel Certification Governance Committee (PCGC), which is independent of the NERC board, should explore expanding the certification requirements of system operating personnel to include additional measures of competency in recognizing and responding to system emergencies. The current NERC certification examination is a written test of the NERC Operating Manual and other references relating to operator job duties, and is not by itself intended to be a complete demonstration of competency to handle system emergencies.

Recommendation 7. Evaluate Reactive Power and Voltage Control Practices.

The August 14 blackout investigation identified inconsistent practices in northeastern Ohio with regard to the setting and coordination of voltage limits and insufficient reactive power supply. Although the deficiency of reactive power supply in northeastern Ohio did not directly cause the blackout, it was a contributing factor and was a significant violation of existing reliability standards.

In particular, there appear to have been violations of NERC Planning Standard I.D.S1 requiring static and dynamic reactive power resources to meet the performance criteria specified in Table I of

[5] The term "realistic simulations" includes a variety of tools and methods that present operating personnel with situations to improve and test diagnostic and decision-making skills in an environment that resembles expected conditions during a particular type of system emergency. Although a full replica training simulator is one approach, lower cost alternatives such as PC-based simulators, tabletop drills, and simulated communications can be effective training aids if used properly.

Planning Standard I.A on Transmission Systems. Planning Standard II.B.S1 requires each regional reliability council to establish procedures for generating equipment data verification and testing, including reactive power capability. Planning Standard III.C.S1 requires that all synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. S2 of this standard also requires that generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units.

On one hand, the unsafe conditions on August 14 with respect to voltage in northeastern Ohio can be said to have resulted from violations of NERC planning criteria for reactive power and voltage control, and those violations should have been identified through the NERC and ECAR compliance monitoring programs (addressed by Recommendation 2). On the other hand, investigators believe these deficiencies are also symptomatic of a systematic breakdown of the reliability studies and practices in FE and the ECAR region that allowed unsafe voltage criteria to be set and used in study models and operations. There were also issues identified with reactive characteristics of loads, as addressed in Recommendation 14.

Recommendation 7a: The Planning Committee shall reevaluate within one year the effectiveness of the existing reactive power and voltage control standards and how they are being implemented in practice in the ten NERC regions. Based on this evaluation, the Planning Committee shall recommend revisions to standards or process improvements to ensure voltage control and stability issues are adequately addressed.

Recommendation 7b: ECAR shall no later than June 30, 2004 review its reactive power and voltage criteria and procedures, verify that its criteria and procedures are being fully implemented in regional and member studies and operations, and report the results to the NERC board.

Recommendation 8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

The importance of automatic control and protection systems in preventing, slowing, or mitigating the impact of a large-scale outage cannot be stressed enough. To underscore this point, following the trip of the Sammis-Star line at 4:06, the cascading failure into parts of eight states and two provinces, including the trip of over 531 generating units and over 400 transmission lines, was completed in the next eight minutes. Most of the event sequence, in fact, occurred in the final 12 seconds of the cascade. Likewise, the July 2, 1996 failure took less than 30 seconds and the August 10, 1996 failure took only 5 minutes. It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. The NERC investigators believe that two measures would have been crucial in slowing or stopping the uncontrolled cascade on August 14:

- Better application of zone 3 impedance relays on high voltage transmission lines
- Selective use of under-voltage load shedding.

First, beginning with the Sammis-Star line trip, most of the remaining line trips during the cascade phase were the result of the operation of a zone 3 relay for a perceived overload (a combination of high amperes and low voltage) on the protected line. If used, zone 3 relays typically act as an overreaching backup to the zone 1 and 2 relays, and are not intentionally set to operate on a line overload. However, under extreme conditions of low voltages and large power swings as seen on August 14, zone 3 relays can operate for overload conditions and propagate the outage to a wider area by essentially causing the system to "break up". Many of the zone 3 relays that operated during the August 14 cascading outage were not set with adequate margins above their emergency thermal ratings. For the short times involved, thermal heating is not a problem and the lines should not be tripped for overloads. Instead, power system protection devices should be set to address the specific condition of concern, such as a fault, out-of-step condition, etc., and should not compromise a power system's inherent physical capability to slow down or stop a cascading event.

Recommendation 8a: All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions[6]. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.

A second key finding with regard to system protection was that if an automatic under-voltage load shedding scheme had been in place in the Cleveland-Akron area on August 14, there is a high probability the outage could have been limited to that area.

Recommendation 8b: Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region that could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are to complete the initial studies and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within critical areas, as determined by the studies to be effective in preventing an uncontrolled cascade of the power system.

The NERC investigation of the August 14 blackout has identified additional transmission and generation control and protection issues requiring further analysis. One concern is that generating unit control and protection schemes need to consider the full range of possible extreme system conditions, such as the low voltages and low and high frequencies experienced on August 14. The team also noted that improvements may be needed in under-frequency load shedding and its coordination with generator under-and over-frequency protection and controls.

[6] The NERC investigation team recommends that the zone 3 relay, if used, should not operate at or below 150% of the emergency ampere rating of a line, assuming a .85 per unit voltage and a line phase angle of 30 degrees.

Recommendation 8c: The Planning Committee shall evaluate Planning Standard III – System Protection and Control and propose within one year specific revisions to the criteria to adequately address the issue of slowing or limiting the propagation of a cascading failure. The board directs the Planning Committee to evaluate the lessons from August 14 regarding relay protection design and application and offer additional recommendations for improvement.

Recommendation 9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.

Ambiguities in the NERC operating policies may have allowed entities involved in the August 14 blackout to make different interpretations regarding the functions, responsibilities, capabilities, and authorities of reliability coordinators and control areas. Characteristics and capabilities necessary to enable prompt recognition and effective response to system emergencies must be specified.

The lack of timely and accurate outage information resulted in degraded performance of state estimator and reliability assessment functions on August 14. There is a need to review options for sharing of outage information in the operating time horizon (e.g. 15 minutes or less), so as to ensure the accurate and timely sharing of outage data necessary to support real-time operating tools such as state estimators, real-time contingency analysis, and other system monitoring tools.

On August 14, reliability coordinator and control area communications regarding conditions in northeastern Ohio were ineffective, and in some cases confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during emergencies, is essential to reliability. Alternatives should be considered to one-on-one phone calls during an emergency to ensure all parties are getting timely and accurate information with a minimum number of calls.

NERC operating policies do not adequately specify critical facilities, leaving ambiguity regarding which facilities must be monitored by reliability coordinators. Nor do the policies adequately define criteria for declaring transmission system emergencies. Operating policies should also clearly specify that curtailing interchange transactions through the NERC Transmission Loading Relief (TLR) Procedure is not intended as a method for restoring the system from an actual Operating Security Limit violation to a secure operating state.

Recommendation 9: The Operating Committee shall complete the following by June 30, 2004:

- **Evaluate and revise the operating policies and procedures, or provide interpretations, to ensure reliability coordinator and control area functions, responsibilities, and authorities are completely and unambiguously defined.**
- **Evaluate and improve the tools and procedures for operator and reliability coordinator communications during emergencies.**
- **Evaluate and improve the tools and procedures for the timely exchange of outage information among control areas and reliability coordinators.**

Recommendation 10. Establish Guidelines for Real-Time Operating Tools.

The August 14 blackout was caused by a lack of situational awareness that was in turn the result of inadequate reliability tools and backup capabilities. Additionally, the failure of FE's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure of its state estimator to work effectively on August 14 contributed to the lack of situational awareness.

Recommendation 10: The Operating Committee shall within one year evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.

This evaluation should include consideration of the following:

- Modeling requirements, such as model size and fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement, observability, update procedures, and procedures for the timely exchange of modeling data.
- State estimation requirements, such as periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including times between failures, presentation of solution results including alarms, and troubleshooting procedures.
- Real-time contingency analysis requirements, such as contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies.

Recommendation 11. Evaluate Lessons Learned During System Restoration.

The efforts to restore the power system and customer service following the outage were effective, considering the massive amount of load lost and the large number of generators and transmission lines that tripped. Fortunately, the restoration was aided by the ability to energize transmission from neighboring systems, thereby speeding the recovery. Despite the apparent success of the restoration effort, it is important to evaluate the results in more detail to determine opportunities for improvement. Blackstart and restoration plans are often developed through study of simulated conditions. Robust testing of live systems is difficult because of the risk of disturbing the system or interrupting customers. The August 14 blackout provides a valuable opportunity to apply actual events and experiences to learn to better prepare for system blackstart and restoration in the future. That opportunity should not be lost, despite the relative success of the restoration phase of the outage.

Recommendation 11a: The Planning Committee, working in conjunction with the Operating Committee, NPCC, ECAR, and PJM, shall evaluate the black start and system restoration performance following the outage of August 14, and within one year report to the NERC board the results of that evaluation with recommendations for improvement.

Recommendation 11b: All regional reliability councils shall, within six months of the Planning Committee report to the NERC board, reevaluate their procedures and plans to assure an effective blackstart and restoration capability within their region.

Recommendation 12. Install Additional Time-Synchronized Recording Devices as Needed.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.

NERC Planning Standard I.F – Disturbance Monitoring does require location of recording devices for disturbance analysis. Often time, recorders are available, but they are not synchronized to a time standard. All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS) synchronizing signal. Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability.

Time-synchronized devices, such as phasor measurement units, can also be beneficial for monitoring a wide-area view of power system conditions in real-time, such as demonstrated in WECC with their Wide-Area Monitoring System (WAMS).

Recommendation 12a: The reliability regions, coordinated through the NERC Planning Committee, shall within one year define regional criteria for the application of synchronized recording devices in power plants and substations. Regions are requested to facilitate the installation of an appropriate number, type and location of devices within the region as soon as practical to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.

Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization and, as necessary, install additional dynamic recorders.

Recommendation 13. Reevaluate System Design, Planning and Operating Criteria.

The investigation report noted that FE entered the day on August 14 with insufficient resources to stay within operating limits following a credible set of contingencies, such as the loss of the East Lake 5 unit and the Chamberlin-Harding line. NERC will conduct an evaluation of operations planning practices and criteria to ensure expected practices are sufficient and well understood. The review will reexamine fundamental operating criteria, such as n-1 and the 30-minute limit in preparing the system for a next contingency, and Table I Category C.3 of the NERC planning standards. Operations planning and operating criteria will be identified that are sufficient to ensure the system is in a known and reliable condition at all times, and that positive controls, whether manual or automatic, are available and appropriately located at all times to return the Interconnection to a secure condition. Daily operations planning, and subsequent real time operations planning will identify available system reserves to meet operating criteria.

Recommendation 13a: The Operating Committee shall evaluate operations planning and operating criteria and recommend revisions in a report to the board within one year.

Prior studies in the ECAR region did not adequately define the system conditions that were observed on August 14. Severe contingency criteria were not adequate to address the events of August 14 that led to the uncontrolled cascade. Also, northeastern Ohio was found to have insufficient reactive support to serve its loads and meet import criteria. Instances were also noted in the FE system and ECAR area of different ratings being used for the same facility by planners and operators and among entities, making the models used for system planning and operation suspect. NERC and the regional reliability councils must take steps to assure facility ratings are being determined using consistent criteria and being effectively shared and reviewed among entities and among planners and operators.

Recommendation 13b: ECAR shall no later than June 30, 2004 reevaluate its planning and study procedures and practices to ensure they are in compliance with NERC standards, ECAR Document No. 1, and other relevant criteria; and that ECAR and its members' studies are being implemented as required.

Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.

Regional reliability councils may consider assembling a regional database that includes the ratings of all bulk electric system (100 kV and higher voltage) transmission lines, transformers, phase angle regulators, and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis.

NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area.

Recommendation 14. Improve System Modeling Data and Data Exchange Practices.

The after-the-fact models developed to simulate August 14 conditions and events indicate that dynamic modeling assumptions, including generator and load power factors, used in planning and operating models were inaccurate. Of particular note, the assumptions of load power factor were overly optimistic (loads were absorbing much more reactive power than pre-August 14 models indicated). Another suspected problem is modeling of shunt capacitors under depressed voltage conditions. Regional reliability councils should establish regional power system models that enable the sharing of consistent, validated data among entities in the region. Power flow and transient stability simulations should be periodically compared (benchmarked) with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

Recommendation 14: The regional reliability councils shall within one year establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data shall be exchanged on an inter-regional basis as needed for reliable system planning and operation.

During the data collection phase of the blackout investigation, when control areas were asked for information pertaining to merchant generation within their area, data was frequently not supplied. The reason often given was that the control area did not know the status or output of the generator at a given point in time. Another reason was the commercial sensitivity or confidentiality of such data.

Attachment A to Recommendation 1

Corrective Actions to Be Taken by FirstEnergy, Midwest Independent System Operator and PJM Draft – January 26, 2004

This attachment identifies corrective actions to be completed by FE, MISO, and PJM no later than June 30, 2004, as referenced in NERC Recommendation 1. These actions are intended to assure peer operating systems and reliability coordinators, regulators, electricity customers, and the public that the specific deficiencies leading to the August 14, 2003 cascading outage have been resolved and will not be the cause of a similar outage in the near future.

A. Corrective Actions to Be Completed by FirstEnergy

FirstEnergy shall complete the following corrective actions by June 30, 2004. Unless otherwise stated, the requirements apply to FE's northern Ohio system and connected generators.

1. Voltage Criteria and Reactive Resources

a. **Interim Voltage Criteria.** The investigation team found that FE was not operating on August 14 within NERC planning and operating criteria with respect to its voltage profile and reactive power supply margin in the Cleveland-Akron area. FE was also operating in apparent violation of its own historical planning and operating criteria that were developed and used by Centerior Energy Corporation (The Cleveland Electric Illuminating Company and the Toledo Edison Company) prior to 1998 to meet the relevant NERC and ECAR standards and criteria. FE's stated acceptable ranges for voltage are not compatible with neighboring systems or interconnected systems in general.

   Until such time that the study of the northern Ohio system ordered by the Federal Energy Regulatory Commission (FERC) on December 23 is completed, and until FE is able to determine (in b. below) a current set of voltage and reactive requirements verified to be within NERC and ECAR criteria, FE shall immediately operate such that voltages at all 345 kV buses in the Cleveland-Akron area shall have a minimum voltage of .95 per unit following the simultaneous loss of the two largest generating units in that area.

b. **Calculation of Minimum Bus Voltages and Reactive Reserves.** FE shall, consistent with or as part of the FERC-ordered study, determine the minimum location-specific voltages at all 345 kV and 138 kV buses and all generating stations within their control area (including merchant plants). FE shall determine the minimum dynamic reactive reserves that must be maintained in local areas to ensure that these minimum voltages are met following contingencies studied in accordance with ECAR Document 1. Criteria and minimum voltage requirements must comply with NERC planning criteria, including Table 1A, Category C3, and Operating Policy 2.

c. **Voltage Procedures.** FE shall determine voltage and reactive criteria and procedures to enable operators to understand and operate to these criteria.

d. **Study Results.** When the FERC-ordered study is completed, FE is to adopt the planning and operating criteria determined as a result of that study and update the operating criteria and procedures for its system operators. If the study indicates a need for system reinforcements, FE shall develop a plan for developing such reinforcements as soon as practical, and shall develop operational procedures or other mitigating programs to maintain safe operating conditions until such time that the necessary system reinforcements can be made.

e. **Reactive Resources.** FE shall inspect all reactive resources, including generators, and assure that all are fully operational. FE shall verify that all installed capacitors have no blown fuses and that at least 98% of installed capacitors at 69 kV and higher are available and in service during the summer 2004.

f. **Communications.** FE shall communicate its voltage criteria and procedures, as described in the items above to MISO and FE's neighboring systems.

2. Operational Preparedness and Action Plan

FE's 2003 Summer Assessment was not considered to be sufficiently comprehensive to cover a wide range of known and expected system conditions, nor effective for the August 14 conditions based on the following:

- No voltage stability assessment was included to assess the Cleveland-Akron area which has a long-known history of potential voltage collapse, as indicated CEI studies prior to 1997, by non-convergence of powerflow studies in the 1998 analysis, and advice from AEP of potential voltage collapse prior to the onset of 2003 summer load period.
- Only single contingencies were tested for basically one set of 2003 study conditions. This does not comply with the study requirements of ECAR Document 1.
- Study conditions should have assumed a wider range of generation dispatch and import/export and inter-regional transfers. For example, imports from MECS (north-to-south transfers) are likely to be less stressful to the FE system than imports from AEP (south-to-north transfers). Sensitivity studies should have been conducted to assess the impact of each key parameter and derive the system operating limits accordingly based on the most limiting of transient stability, voltage stability and thermal capability.

- The 2003 study conditions are considered to be more onerous than those assumed in the 1998 study, since the former has Davis Besse (830 MW) as a scheduled outage. However, the 2003 study does not show any voltage instability problems as shown by the 1998 study.
- The 2003 study conditions are far less onerous than the actual August 14 conditions from the generation and transmission availability viewpoint. This is another indication that n-1 contingency assessment, based on one assumed system condition, is not sufficient to cover the variability of changing system conditions due to forced outages.

FE shall prepare and submit to ECAR, with a copy to NERC, an Operational Preparedness and Action Plan to ensure system security and full compliance with NERC and planning and operating criteria, including ECAR Document 1. The action plan shall include, but not be limited to the following:

a. **2004 Summer Studies.** Complete a 2004 summer study to identify a comprehensive set of System Operating Limits (SOL) and Interconnection Reliability Limits (IRLs) based on the NERC Operating Limit Definition Task Force Report. Any inter-dependency between FE's SOL and those of its neighboring entities, known and forecasted regional and interregional transfers shall be included in the derivation of SOL and IRL.

b. **Extreme Contingencies.** Identify high risk contingencies that are beyond normal studied criteria and determine the performance of the system for these contingencies. Where these extreme contingencies result in cascading outages, determine means to reduce their probability of occurrence or impact. These contingencies and mitigation plans must be communicated to FE operators, ECAR, MISO, and neighboring systems.

c. **Maximum Import Capability.** Determine the maximum import capability into the Cleveland-Akron area for the summer of 2004, consistent with the criteria stated in (1) above and all applicable NERC and ECAR criteria. The maximum import capability shall take into account historical and forecasted transactions and outage conditions expected with due regard to maintaining adequate operating and local dynamic reactive reserves.

d. **Vegetation Management.** FE was found to not be complying with its own procedures for right-of-way maintenance and was not adequately resolving inspection and forced outage reports indicating persistent problems with vegetation contacts prior to August 14, 2003. FE shall complete rights-of-way trimming for all 345 kV and 138 kV transmission lines, so as to be in compliance with the National Electrical Safety Code criteria for safe clearances for overhead conductors, other applicable federal, state and local laws, and FE's right-of-way maintenance procedures. Priority should be placed on completing work for all 345 kV lines as soon as possible. FE will report monthly progress to NERC and ECAR.

e. **Line Ratings.** FE shall reevaluate its criteria for calculating line ratings, survey the 345 kV and 138 kV rights-of-way by visual inspection to ensure line ratings are appropriate for the clearances observed, and calculate updated ratings for each line. FE shall ensure that system operators, MISO, ECAR, NERC (MMWG), and neighboring systems are informed of and able to use the updated line ratings.

3. **Emergency Response Capabilities and Preparedness**

   a. **Emergency Response Resources.** FE shall develop a capability no later than June 30, 2004 to reduce load in the Cleveland-Akron area by 1,500 MW within ten minutes of a directive to do so by MISO or the FE system operator. Such a capability may be provided by automatic or manual load shedding, voltage reduction, direct-controlled commercial or residential load management, or any other method or combination of methods capable of achieving the 1,500 MW of reduction in ten minutes without adversely affecting other interconnected systems. The amount of required load reduction capability may be reduced to an amount shown by the FERC-ordered study to be sufficient for response to severe contingencies and if approved by ECAR and NERC.

   b. **Emergency Response Plan.** FE shall develop emergency response plans, including plans to deploy the load reduction capabilities noted above. The plan shall include criteria for declaring an emergency and various states of emergency. The plan shall include detailed description of authorities, operating procedures, and communication protocols with all the relevant entities including MISO, FE operators, and market participants within the FE area that have ability move generation or shed load upon orders from FE operators. The plan shall include procedures for load restoration after the declaration that the FE system is no longer in the emergency operating state.

4. **Operating Center and Training**

   a. **Operator Communications.** FE shall develop communications procedures for FE operating personnel to use within FE, with MISO and neighboring systems, and others. The procedure and the operating environment within the FE system control center shall allow focus on reliable system operation and avoid distractions such as calls from customers and others who are not responsible for operation of a portion of the transmission system.

   b. **Reliability Monitoring Tools.** FE shall ensure its state estimation and real-time contingency analysis functions are being used to reliably execute full contingency analysis automatically every ten minutes, or on demand, and to alarm operators of potential first contingency violations.

   c. **System Visualization Tools.** FE shall provide its operating personnel with the capability to visualize the status of the power system from an overview perspective and to determine critical system failures or unsafe conditions quickly without multiple-step searches for failures. A dynamic map board or equivalent capability is encouraged.

d. **Backup Functions and Center.** FE shall develop and prepare to implement a plan for the loss of its system operating center or any portion of its critical operating functions. FE shall comport with the criteria of the NERC Reference Document – Back Up Control Centers, and ensure that FE is able to continue meeting all NERC and ECAR criteria in the event the operating center becomes unavailable. Consideration should be given to using capabilities at MISO or neighboring systems as a backup capability, at least for summer 2004 until alternative backup functionality can be provided.

e. **GE XA21 System Updates.** Until the current energy management system is replaced, FE shall incorporate all fixes for the GE XA21 system known to be necessary to assure reliable and stable operation of critical reliability functions, and particularly to correct the alarm processor failure that occurred on August 14, 2003.

f. **Operator Training.** Prior to June 30, 2004 FE shall meet the operator training requirements detailed in NERC Recommendation 6.

g. **Technical Support.** FE shall develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of loss of critical functionality and testing procedures.

B. Corrective Actions to Be Completed by MISO

MISO shall complete the following corrective actions no later than June 30, 2004.

1. **Reliability Tools.** MISO shall fully implement and test its topology processor to provide its operating personnel real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages. MISO shall establish a means of exchanging outage information with its members and neighboring systems such that the MISO state estimation has accurate and timely information to perform as designed. MISO shall fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO shall provide backup capability for all functions critical to reliability.

2. **Visualization Tools.** MISO shall provide its operating personnel tools to quickly visualize system status and failures of key lines, generators or equipment. The visualization shall include a high level voltage profile of the systems at least within the MISO footprint.

3. **Training.** Prior to June 30, 2004 MISO shall meet the operator training criteria stated in NERC Recommendation 6.

4. **Communications.** MISO shall reevaluate and improve its communications protocols and procedures with operational support personnel within MISO, its operating members, and its neighboring control areas and reliability coordinators.

5. **Operating Agreements.** MISO shall reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.

C. Corrective Actions to Be Completed by PJM

PJM shall complete the following corrective actions no later than June 30, 2004.

1. **Communications.** PJM shall reevaluate and improve its communications protocols and procedures between PJM and its neighboring reliability coordinators and control areas.

NOTICE OF PUBLIC HEARING

The Public Service Commission of Kentucky will hold a hearing on February 25, 2004, at 9:00 a.m., Eastern Standard Time, in Hearing Room 1 of the Commission's offices, located at 211 Sower Boulevard in Frankfort, Kentucky, for the purpose of cross-examining witnesses in Case No. 2003-00266, which is an investigation into the membership of Louisville Gas and Electric Company in the Midwest Independent Transmission System Operator, Inc.

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I, Barbara Stenger of THE COURIER JOURNAL and LOUISVILLE TIMES COMPANY, clerk of THE COURIER JOURNAL, a newspaper of general circulation printed and published at Louisville, Kentucky, do solemnly swear that from my own personal knowledge, and 'reference to the files of said publication, the advertisement of: NOTICE OF PUBLIC HEARING

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Barbara Stenger
(Signature of person making proof)

Subscribed and sworn to before me this 23 day of February 2004

Lisa S. Smith
Lisa S Smith

LGE/KU Exhibit / (Collection)

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STATE OF KENTUCKY

COUNTY OF Franklin

Before me, a Notary Public, in and for said County and State, this 20th day of February, 2004, came Rachel McCarty personally known to me, who being duly sworn, states as follows:

That she is Advertising Assistant of the Ky Press Association, and that the following publications: see Attached ran the Legal Notice for Kentucky Utilities, Notice to Company Customers.

Rachel McCarty
Signed

Bonnie J. Howard
Notary Public

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November 30, 2001

David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First St., N.E.
Washington, DC 20426

Re: Docket Nos. RT01-88-000, -001, -002, -003, -004, -005, -006, -007, -008, -009, -010, -011, -012; ER99-3144-000, -001, -002, -003, -004, -005, -006, -007, -008, -009, -010, -011, -012, -013, -014; EC99-80-000, -001, -002, -003, -004, -005, -006, -007, -008, -009, -010, -011, -012, -013, -014; EL01-80-002; RT01-37-000; RT01-84-000, -001; RT01-26-000, -001; ER01-123-000, -001, -002, -003, -004; ER01-2995-000; ER01-2993-000; ER01-2999-000; ER01-2997-000; ER01-2992-000; RT01-87-000, -001, -002; ER01-780-003; ER01-966-002; ER01-3000-000; RT01-101-000; EC01-146-000; ER00-3295-000, -001, -002; EC01-137-000; EL01-116-000; and ER02-108-000

Dear Secretary Boergers,

On November 9, 2001, the Commission sent a letter to various state public utility commissions concerning RTO formation in the Midwest. This response is filed on behalf of the state public utility commissions of Michigan, North Dakota, Iowa, Arkansas, Pennsylvania, Virginia, Wisconsin, Oklahoma and Kentucky (hereinafter "Midwest State Commissions") and reflects their consensus view on the questions posed by the Commission. Several of the state signatories to this letter are also submitting separate letters supplementing their responses. The Midwest State Commissions thank the Commission for its interest in their viewpoints and for its efforts to promote broad, competitive regional markets.

1. **What RTO structure – a single RTO, multiple RTOs with seams agreements, or other – would most efficiently administer the transmission system and facilitate electric power trading to meet the needs of customers over the entire Midwest?**

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Response:

The short answer to this question is that a single RTO would most efficiently administer the transmission system and facilitate electric power trading in the Midwest.[1] Order No. 2000 establishes the sound principle that an RTO must be of sufficient scope and configuration to promote efficient trading to the benefit of consumers. Several midwestern state commissions, in fact, have advocated a single regional transmission organization even before issuance of the NOPR that led to Order No. 2000, urging that approach in a Section 206 filing in February 1998.[2]

Each region of the country has its own unique circumstances, institutions and past history that must be considered in deciding the proper scope and governance structure for the RTO(s) in that region. For example, it might well be feasible in some regions to achieve the functional equivalent of a single RTO using multiple RTOs through agreements to establish a single regionwide rate, adopt common market design, joint planning, etc. The Midwest State Commissions' experience to date with RTO formation in the Midwest, however, leads us to conclude that in the Midwest, this approach has not worked and will not work.

Last spring, the Commission approved a settlement agreement that, in theory, would have allowed the Midwest ISO and a proposed Alliance RTO to achieve through an Inter-RTO Cooperation Agreement (IRCA) the goal of a seamless energy market in the midwest.[3] Since that time, however, there has been little progress.[4] That fact, coupled with changed circumstances, leads us to conclude that an IRCA approach may no longer be reasonable and that only a single Midwest RTO can achieve the goals of Order No. 2000.

It bears no small emphasis that only the Midwest ISO, as between it and the Alliance Companies, currently has a control center and an infrastructure in place to provide operational control over the transmission facilities under its responsibility. Equally important, despite the

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[1] By the term "Midwest," the signatories to this letter mean that region as traditionally defined. As the Commission is aware, the proposed Alliance RTO footprint includes certain states not traditionally considered part of the Midwest (*e.g.*, Virginia, North Carolina and Pennsylvania). Subject to its comments filed separately on November 30, 2001, the Virginia State Corporation Commission joins in and adopts these comments. Certain other state commissions are also commenting separately, as well as joining in the instant response. Kentucky is not filing a separate letter but would note that, even with a single Midwest RTO, there remain seams and structural issues to address, particularly as they pertain to the relationship between TVA and municipal utilities and rural electric cooperatives in Kentucky.

[2] The petition, submitted in Docket No. PL98-3, was filed on behalf of the state regulatory commissions of Arkansas, Illinois, Kansas, Michigan, Minnesota, Missouri, North Dakota, Ohio, Oklahoma, Pennsylvania and Texas.

[3] *Illinois Power Co.*, 95 FERC ¶ 61,183 at 61,640, 61,648, 61,650 (2001).

[4] See, e.g., Protest of the Michigan Public Service Commission, Illinois Commerce Commission, et al. in Alliance Cos., Docket Nos. ER99-3144-009, EC99-80-009, RT01-88-001 (filed June 18, 2001). See also, Comments of the Illinois Commerce Commission in Midwest ISO, Docket No. RT01-87-001 (filed September 21, 2001; Request for Rehearing of the Illinois Commerce Commission, the Michigan Public Service Commission, the Indiana Utility Regulatory Commission, the Pennsylvania Public Utility Commission and the Public Utilities Commission of Ohio in Alliance Cos., Docket Nos. RT01-88-000 (filed August 13, 2001).

Commission's clear directives – now five months old -- there is still no independent board in place to implement the Alliance RTO plan.[5] As for IRCA implementation, the Midwest State Commissions had hoped that commitments to develop "*compatible*" approaches to congestion management, transmission planning, calculation of available transmission capacity, etc. would lead to *common* solutions.[6] Instead, little progress has been made, a problem exacerbated by the fact that the Alliance transmission owners, not an independent board, are currently in charge of the Alliance's efforts to coordinate with the Midwest ISO under IRCA. The implementation of IRCA is further complicated by the facts that the Midwest ISO and the Southwest Power Pool may merge[7] and that one of the Alliance members, International Transmission Company, has pulled out to join the Midwest ISO.

2. **How should market interface and reliability issues at the seams be resolved with multiple RTOs?**

Response:

As implied in the prior answer, the best way to resolve market interface and reliability issues at the seams is to reduce the number of seams. In the Midwest, that means movement to a single RTO. Absent such a solution, however, the Midwest State Commissions urge the Commission to require adjoining RTOs to use common, rather than simply compatible approaches to key issues, such as market design, transmission planning, reliability criteria, and calculation of available transmission capacity. Too many disputes can arise over what constitutes a compatible approach. Multiple RTOs can also develop joint rates, as contemplated under the Alliance/Midwest ISO settlement. Appropriately priced, such an approach can capture a significant portion of the benefits of a single RTO.

3. **Order No. 2000 permits hybrid RTOs. If the functions specified in Order No. 2000 are shared or coordinated among separate organizations within a hybrid RTO, how would you suggest that those functions be apportioned?**

    a) **For example, within a hybrid RTO, which type of organization should perform planning and expansion, OASIS administration, market monitoring, security coordination, and interregional coordination?**

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[5] See the Commission's July 12, 2001 order in *Alliance Cos.*, 96 FERC ¶ 61,052 at 61,135, 61,146 (2001) (directing Alliance Companies to form an independent board "from the date of this order").

[6] By "common" solutions, the Midwest State Commissions refer to single solutions or approaches jointly adopted. "Compatible" approaches are not identical, but in theory can be melded together. In practice, a commitment to compatible approaches appears to leave too much discretion for interpretation and disagreement.

[7] On October 19, 2001 MISO and SPP issued a joint press release stating that they had "reached agreement on terms for the consolidation of the two organizations."

Response:

The apportionment of functions among various entities within a hybrid RTO has evolved into one of the critical issues pending before the Commission, particularly in situations, as in the Midwest, where a number of entities either are vying for RTO status or are negotiating the terms and conditions of joining an RTO as a Transco or an Independent Transmission Company ("ITC"). In the Midwest, moreover, defining and distinguishing between for profit Transcos and ITCs is a critical part of the analysis. To the Midwest State Commissions' knowledge, there are not clearly defined distinctions between Transcos and ITCs. The Transcos that have been proposed, however, have tended to be structured as RTOs. The Alliance Transco is such a model. By contrast, many of the ITCs that have been proposed have been structured simply as transmission companies operating within an RTO. The ITCs within the Midwest ISO fall into the latter category. For purposes of these responses, the Midwest State Commissions therefore find it useful to define Transcos as companies intended to be RTOs or to assume most of their functions. Under this definition there would be no more than one Transco per RTO. By contrast, the Midwest State Commissions define an ITC as one of several independent transmission companies that may operate within an RTO. Both Transcos and ITCs may qualify as independent transmission companies operating within an RTO where passive ownership by market participants can be established, but, as discussed later, the Midwest State Commissions believe that the greater the degree of passive ownership by market participants the less their level of independence and the fewer functions they should be allowed to perform within an RTO.

As a very general proposition, if a Transco had ownership of *all* of the transmission facilities within a properly configured region of adequate scope, and if it was fully independent of market participants (ie, unencumbered even by passive ownership interests held by market participants) it could be structured to assume the functions of the RTO other than reliability assurance and market monitoring.[8] In such a situation, for example, the Transco could be structured so that before it undertook transmission expansions, it would have to place congestion solutions out for bid. In this way, merchant transmission companies, demand side management companies and distributed generation providers could vie with the Transco on even terms in a transparent process for relief of congestion and reliability problems.

The problem with the single for-profit Transco as RTO model described above, however, is that it does not appear likely to develop in the Midwest, given the Commission's RTO-related precedent to date, the structures of the various proposals[9] and the actions of the transmission

[8] In this respect, the Midwest State Commissions agree with National Grid that the operation of energy markets, market monitoring, and interregional market development are not proper functions for a for-profit Transco to perform. See "Response of National Grid USA to Questions Posed by the Commission." Docket No. EX02-3-000 (filed November 2, 2001).

[9] The Transco proposed by Alliance is not fully divested of market participant ownership. Indeed, the already substantial passive ownership interests of market participants can even increase under the Alliance model. This market participant presence poses a continuous and burdensome challenge to the Transco's independence. As important, the Alliance Transco would not even own all the transmission within the Alliance region, much less in the broader Midwest region that would make a more logical and efficient configuration. Indeed, one of the major Alliance participants, International Transmission Company, has withdrawn from Alliance. In these circumstances,

owners in the region.[10] In other words, under present circumstances, there seems to be scant likelihood that the Alliance Transco owners would relinquish all passive ownership interests or that the various ITCs within MISO will agree to merge with themselves and the Alliance Transco to form a single, fully independent Transco. As a practical matter, therefore, in deciding how to apportion functions within an RTO, what the Commission may be left with addressing is the division of responsibilities between the RTO and its constituent multiple ITCs. The remainder of the Midwest State Commission responses therefore assume this multiple ITC-within-an-RTO model and it is this model which the Midwest State Commissions have in mind when they discuss the concept of a hybrid RTO.

Keeping the above-defined terms in mind, the states generally favor a case-by-case approach to determine how functions should be shared among members of a hybrid RTO. Such an approach allows for flexibility to address unique regional concerns and to encourage the formation of innovative structures that improve the overall menu and quality of services offered by an RTO. For example, the Commission may determine that ITCs must be truly independent, with no passive ownership in other energy companies before becoming eligible to assume responsibility for certain RTO functions. Further, upon obtaining independent status, the ITCs must then maintain such status or lose any right they have been granted to perform RTO functions. Moreover as regional markets evolve and mature, a case-by-case approach will allow the Commission policies regarding sharing of functions to evolve with the markets.

There are, however, certain core functions that the states believe must be performed by the RTO, and that should not be delegated down to an ITC or a Transco. A brief discussion of the pro and cons of sharing various RTO characteristics and functions in a multiple ITC-within-an-RTO framework is set forth below:

A. Characteristics

1. Independence

Decisionmaking functions[11] should not be performed by an ITC if the independence of the RTO would be compromised thereby. In this respect, the Midwest State Commissions believe that any entity which owns some but not all transmission assets covered by its functions

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an Alliance-type Transco simply could not assume many of the RTO functions without creating more problems than it solves. For example, it could not assume the entire transmission planning function because it would not be the only transmission company within the RTO. Nor could it be in charge of tariff administration – again because it could make decisions that would be in conflict with other transmission companies within the RTO.

[10] Only one Alliance company to date (Commonwealth) has indicated a willingness to divest its transmission facilities. As important, the transmission owners within the Midwest ISO appear unwilling to adopt the Alliance Transco model.

[11] As the Midwest State Commissions explain, *infra*, ITCs and Transcos within an RTO could assume certain *duties*, such as transmission planning and service curtailment, provided that the ultimate decisionmaking function remains in the hands of the independent RTO.

would have a bias towards its own transmission assets that would create an inherent conflict. Leaving decisionmaking authority for such functions in the hands of a single ITC would be inherently unworkable, as would allowing all of the ITCs within the RTO to make potentially conflicting decisions. Thus, any ultimate decisionmaking functions that could have a monetary effect on transactions, such as tariff implementation, rate design, transmission planning, congestion management, should not be performed by an entity which is biased towards certain transmission assets. The Midwest State Commissions believe that the validity of the single Transco model depends upon the Transco owning all of the assets in an RTO. Once it is determined, however, that a Transco will be a subset of a larger RTO footprint, i.e., that it will be one of several ITCs within an RTO, however, there should be no basis for treating Transcos and ITCs differently for purposes of qualifying to perform RTO functions. These entities serve important functions as vehicles for facilitating the divestiture of transmission assets. They should therefore be placed on a level playing field and should be eligible to assume some RTO functions upon a proper showing to the Commission that true independence has been obtained and can be maintained. That said, an ITC that is fully divested of ownership by market participants is better positioned to qualify to assume RTO functions than an ITC or Transco that is encumbered by significant passive ownership interests held by market participants.

2. Scope and Regional Configuration

As indicated in response to Question No. 1, the Midwest State Commissions support a single RTO for the Midwest (as that region has been traditionally defined). By definition, the large geographic scope of the Midwest RTO makes it virtually certain that a Transco will be a subset of a larger RTO footprint. More specifically, the Midwest ISO region encompasses many transmission systems. There are already two transmission companies that have been formed within MISO – American Transmission Company (ATC) and TransLink. A third, International Transmission Company (ITC) has jumped from Alliance to the Midwest ISO. There is virtually no chance that these companies would turn over all their assets to a single transco. As for the Alliance Transmission Companies, if National Grid is found by the Commission to qualify as a non-market participant and to meet the standards for control of the Alliance transmission systems, National Grid, like ATC, ITC and TransLink, could become an ITC within a single Midwest RTO.

3. Operational Authority

The RTO must retain ultimate responsibility over operational decisions. However, given the independence of an ITC from all market participants, certain operational tasks like dispatching and localized curtailments of service to preserve reliability could be delegated to an ITC as long as ultimate responsibility remains with the RTO.

4. Short term Reliability

Similarly, the RTO should retain ultimate responsibility for short-term reliability. While reliability events may occur at the local level that require independent action by an ITC (a limited form of delegation of RTO duties), the short-term reliability function is vital to the stable operation of the regional transmission grid, and hence should remain with the RTO.

B. Fulfillment of Minimum RTO Functions Under an ISO/ITC Model

1. Tariff Administration and Design

Order No. 2000 requires the RTO to be the sole provider of transmission service and the sole administrator of its own open access tariff. Clearly, an independent RTO, free from biases, must be the sole administrator of a single RTO-wide transmission tariff and must have full authority to propose changes to such tariff. This independence is essential to non-discriminatory, open access transmission service. ITCs and individual participating transmission owners, however, should coordinate with the RTO in the filing of their respective transmission revenue requirements, to ensure their recovery of just and reasonable transmission-related costs.

2. Congestion Management

The Midwest State Commissions believe that congestion management is a function which must be addressed and administered by the RTO. Any sharing of congestion management between the RTO and ITCs presents the potential for inconsistent approaches towards congestion management within the RTO and a bias towards transmission solutions. Congestion management performed by a single Transco would have an additional obvious bias within the Transco towards the assets owned by the Transco.

3. Parallel Path Flow

The RTO must be responsible for controlling and finding solutions to issues arising from parallel path flow. Assigning parallel path flow functions to an ITC or a Transco within the RTO would negate the benefit of internalizing path flows within a larger RTO or designing common compensation schemes for substantial loop flows caused (1) on individual transmission systems within an RTO by contract path schedules on other systems within that same RTO or (2) on neighboring transmission systems by contract path schedules arranged on the RTO.

4. Ancillary Services

Ancillary services should be administered at the RTO level under standardized procedures.

5. OASIS, Total Transmission Capability (TTC) and Available Transmission Capability (ATC)

Given the independence of an ITC, and as an incentive for promoting the formation of fully divested ITCs, responsibility for calculating TTC and ATC could be delegated to ITCs.

The RTO, however, should remain responsible for standardizing the methodology for performing such calculations and for resolving any conflicts.

6. Market Monitoring

Market monitoring is a function that must be performed by an independent body. There are no conceivable circumstances which could justify an ITC or a Transco performing the function of market monitor. See, e.g., the comments filed by the state regulatory commissions of Arkansas, Indiana, Kentucky, Michigan, Missouri, Ohio and Virginia in Docket No. RT01-88-010.

7. Planning and Expansion

As noted *infra* in connection with the discussion of Appendix I to the Midwest ISO tariff, the Midwest State Commissions believe that ultimate authority for transmission planning and expansion decisions, subject to all necessary state and federal approvals, must lie with the RTO to avoid the inherent biases of even an independent ITC in favor of (1) transmission solutions to congestion problems that might also be addressed by non-transmission solutions such as demand side management or distributed generation and (2) expansion of the transmission system by the ITC, rather than through merchant transmission projects, expansion of neighboring transmission systems, or other third-party transmission projects. This is not to say that the ITC would have *no* role in transmission planning. On the contrary, while ITCs should not have ultimate decisionmaking *authority*, ITCs may be given joint planning *duties*, including the right to propose transmission projects. The ITC will have the best knowledge of conditions on, and capabilities of, its system and giving it a stake in the planning process should improve planning outcomes for the RTO region. In those limited circumstances, moreover, where ITCs have proposed uncontested transmission solutions -- i.e., where, after an open planning process affording input from all interested parties has been conducted, no non-transmission solution appears superior to the building of additional transmission, and no other entity has proposed to build the needed transmission on terms more favorable than those proposed by the ITC -- it might well be appropriate for the RTO to defer to the ITC and to delegate it responsibilities for completion of such projects. In contested cases, however, the RTO must determine which project is in the best interest of the RTO region and who should construct it, subject, of course, to all necessary regulatory approvals. The movement of transmission ownership from market participants to ITCs and other third party transmission entities is a positive development, whose future success depends on the ability of such new entities to raise capital. Preserving functions for the ITC within an RTO that do not compromise the RTO's independence, therefore, is important. Giving ITCs a role in planning, construction and operation functions, all under the direction of the RTO, as suggested above, should assist the ITC in raising capital.

8. Interregional Coordination

Interregional coordination, by its very nature, should be administered by the RTO. That is not to say, however, that ITCs and Transcos could not share in this function through delegation by the RTO. Such sharing would be particularly appropriate in circumstances where an ITC or Transco footprint occupies a large geographic area on a seam between RTO boundaries.

b) Is the status of an organization as "for profit" or "not for profit" relevant to the question of which functions it should undertake? Explain.

Response:

It is reasonable to assume that a "for profit" structure will give an entity incentives to behave in a manner which is intended to maximize profits. Thus, the answer to the question posed depends upon how profits can be maximized. For example, an RTO can be structured for profit without owning transmission facilities. If the profits of such an entity are maximized by performing RTO functions in an efficient and competitively neutral fashion then the "for-profit" status may not become a relevant factor in assigning responsibility for RTO functions. This is not to say that there are no distinctions between for profit and not for profit entities. For profit and not for profit RTOs will, by their nature, continue to have somewhat different perspectives and priorities, even if the RTO owns no transmission assets. However, if a RTO (or a Transco) owns transmission assets, the differences in structure have much greater significance. For profit Transcos have an inherent incentive to favor transmission solutions as opposed to alternative solutions, such as distributed generation and demand side management, which could be relevant to whether certain functions, such as transmission planning, can be independently administered by an ITC.[12]

In addition, an ITC which owns some transmission assets and controls (but does not own other transmission assets) would have a bias towards its own facilities which would be relevant to whether certain functions, such as tariff administration or interconnection decisions, could be independently administered by an ITC.[13]

The structure of an organization is relevant to the functions it should perform within an RTO. The more independence is compromised, the less FERC should allow an ITC to perform the public interest functions of an RTO. In his October 12 comments to the Commission in Docket No. RM01-12 on the need for an independent market monitor, Michigan PSC Commissioner Nelson testified that ITCs, while independent of other market participants, may have an inherent bias to favor transmission solutions to congestion as opposed to alternative solutions such as distributed generation and demand side management. Moreover, he added, "to the extent that an ITC controls both transmission assets that it owns and it doesn't own, it may be interested in which transmission facilities are indeed built." Thus, leaving market monitoring (which would include the monitoring of transmission operations) in the hands of a for profit ITC may compromise the independence of an RTO. For these and other reasons, the Midwest State

[12] The key in the Midwest is to develop some solution to existing and likely future system constraints that threaten the viability of competitive markets.
[13] The Midwest State Commissions recognize that this transco transmission bias may be tempered, if not completely offset, by exogenous barriers to transmission construction such as NIMBY.

Commissions believe (as noted above) that an independent body must perform the market monitoring function.

The same inherent ITC bias in favor of transmission solutions to congestion, etc., also militates, as noted in response to Question 3(a), against granting the ITC ultimate transmission planning authority (as contrasted with a role in the planning process) or authority to develop interconnection policy. It bears some note, however, that the issue is not neatly classified as a choice between for profit and not for profit structures. An RTO, for example, can be structured as a for profit entity, even if it owns no transmission assets. Its assets would consist of its control center, computers, software, etc. A for-profit RTO that controlled, but did not own transmission facilities would not have the same biases as an ITC, but would be at risk for business decisions that led, for example, to imprudent expenditures.

c) **As we try to evaluate how functions should be apportioned in a hybrid RTO, is it useful to distinguish between functions that relate solely to operating and administering the transmission grid and functions that relate more to operation and oversight of markets for trading wholesale power and energy?**

Response:

Yes. As discussed in part (a), in the multiple ITC-within an-ISO context, market oversight functions should be performed by an independent entity at the top, whereas it may be appropriate on a case-by-case basis to apportion to ITCs various functions involving planning, operating and administering the transmission grid.

d) **Is Appendix I of the Midwest ISO Agreement a useful model for how functions could be shared among members of a hybrid RTO?**

Response:

The Midwest State Commissions have a number of serious reservations about Appendix I. Nonetheless, under the ITC-within-an-RTO model, and subject to substantial qualifications, the Midwest State Commissions believe, consistent with their earlier discussion, that the Appendix I concept of case-by-case assignment of RTO functions to ITCs can be a useful framework to analyze how functions could be shared among members of a hybrid RTO. Key among those qualifications are that (1) ITC assumption of RTO functions *must* only occur on a case-by-case basis, (2) before an ITC can assume any RTO functions it must specifically request such authority and receive approval from the Commission (3) the Commission should clarify that there are certain functions that cannot be assumed by multiple ITCs and (4) in analyzing individual ITC requests to assume RTO functions the Commission will consider the degree to which the ITC is free of active or passive ownership of shares by market participants. These conditions accomplish two goals. First, they allow the Commission, as it acquires experience with the operation of post-RTO markets, to ascertain whether given functions can be transferred to an ITC. Second, the case-by-case approach ensures that the Commission can establish clear criteria for transfers of functions so that there will be no undue discrimination between ITCs. Using this framework, should entities like National Grid, TransLink, etc, become qualified ITCs within a Midwest RTO, they could petition the Commission for the right to assume specific RTO functions.

In *Commonwealth Edison Co.*, 90 FERC ¶ 61,192 (2000) the Commission described Appendix I to the Midwest ISO agreement as creating:

> a general framework to allow ITCs to operate within the existing structure of the ISO and permit Midwest ISO to assign certain rights, responsibilities, and functions to an ITC including: (1) taking independent action to preserve the security within the ITC; (2) filing with the Commission rate increases, a congestion management program, and a loss methodology for ITC transactions; (3) determining rate discounts for ITC transactions; (4) taking action to correct constraints or curtailing transactions within the ITC; (5) establishing facility ratings and operating procedures, planning the ITC system, and having its determinations take precedence over those of Midwest ISO pending dispute resolution; and (6) collecting separate penalties for congestion management."

90 FERC at 61,626. A number of parties protested Appendix I, complaining, among other things, that the ITC would be assuming responsibility for day-to-day congestion management, reliability and other functions that are properly the responsibility of the RTO. Id. at 61,627.

The Midwest State Commissions agree that these concerns are well taken. While the Commission stated in *Commonwealth Edison* that these concerns were obviated by the requirement in Appendix I that an ITC obtain prior approval from the Commission before assuming any RTO functions of the Midwest ISO, Id. at 61,628, the Midwest State Commissions urge the Commission to provide further guidance with respect to four aspects of Appendix I.

First, Appendix I permits an ITC to seek authority to implement its own intra-ITC congestion management system. See Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Original Sheet No. 213, Section 5. The notion that there could be several congestion management systems within a single RTO conflicts with the development of seamless markets. This is a function that should be under the exclusive control of a single RTO.

Second, Appendix I further permits ITCs not only to file for revenue increases under Section 205, but to develop their own rate designs and incentive rate mechanisms. See Original Sheet No. 212, Section 3.1. The concept of multiple rate designs within a single RTO appears inconsistent with the concept that there be one tariff. It is difficult, moreover, to envision how separate tariffs could work efficiently within the larger RTO service territory. That said, the

Midwest State Commissions do not believe it appropriate to foreclose ITCs the right to demonstrate that such separate rate designs can be reconciled with Order No. 2000. Accordingly, the Midwest State Commissions urge the Commission to clarify that although ITCs should have the opportunity to file pro forma requests for Commission approval of innovative rate designs (consistent with the Appendix I model contemplating prior Commission approval of such requests) they shoulder the heavy burden to demonstrate that such rate designs can coexist with the regionwide RTO tariff for the benefit of all. A different issue might be presented if there were a single Transco that owned all transmission within the RTO, but the problems of multiple rates and rate designs should be avoided by precluding the ITCs from proposing separate rate designs at the outset, except as qualified above.

Third, Appendix I, Section 6 (Original Sheet No. 214) permits an ITC to make unilateral filings to determine loss responsibility within an ITC. This provision, too, conflicts with the single tariff goal of Order No. 2000. An ITC's rights to obtain revenue recovery are already fully protected. Loss factors can be a significant portion of the cost of transmission. Establishing separate loss mechanisms within each ITC zone may serve indirectly to perpetuate an aspect of license plate pricing without further review of its reasonableness.

Fourth, Section 10 of the Appendix would allow the ITC to seek authority to engage in transmission planning without RTO approval. (Original Sheet No. 216). This type of authority presents the concern about a transmission owning entity's inherent bias (1) to favor construction solutions to congestion over demand side management or distributed generation and (2) to favor its own transmission projects over other, competition projects that might be built and owned by others. As noted in response to Question 3(a), while ITCs can and should retain transmission planning *duties*, ultimate planning *authority* ought to reside exclusively with an RTO that does not own transmission assets.

While there are aspects of Appendix I, that, as noted above, would create more uncertainty rather than promote seamless markets, there are other provisions for case-by-case assumption of responsibility by the ITC that appear reasonable. Thus, ITCs would be permitted the opportunity to make a showing to FERC that they should be delegated responsibility for intra-ITC reliability-driven curtailments, establishing operating procedures and ratings for their facilities, and conducting maintenance in coordination with the RTO. To accomplish these objectives the Appendix I language would need to be modified consistent with the above discussion, including a recognition that the greater the degree of passive ownership of an ITC the fewer RTO functions it can reasonably assume.

4. **Order No. 2000 recognizes that wholesale electricity markets are becoming increasingly regional in nature and that new trading patterns are putting additional stress on the interstate transmission system. However, many of the functions that RTOs will be called upon to perform clearly have both regional and local implications (e.g., planning and expansion decisions which ultimately require the siting approval of one or more states). Do you have suggestions regarding how states can work with one another, with the RTO, and with the**

> **FERC to ensure that needed transmission infrastructure is sited and built in a timely manner? With regard to other RTO functions, are additional processes needed to ensure that states have the ability to fulfill their regulatory responsibilities or to adequately protect retail electricity customers?**

Response:

There is no easy answer to this question. The responsibility for regulation of transmission siting varies from state to state, falling to the utility commissions in some states, separate siting agencies in others and a combination of state agencies in still other states. One approach that may hold promise is to expand the concept of the advisory process within an RTO. This advisory process, while not changing existing state siting authority, may be helpful in providing all parties with a greater understanding of regional needs as well as specific local concerns.

The Commission has emphasized that an independent RTO must be free to make and implement decisions even when a majority of stakeholders disagree with its chosen course of action. *See PJM Interconnection*, LLC, 96 FERC ¶ 61,060 at 61,211 (2001); *PJM Interconnection*, LLC, 96 FERC ¶ 61,061 at 61,230 (2001); *Bangor Hydro-Electric Co.*, 96 FERC ¶ 61,063 at 61,259 (2001); *ISO New England, Inc.*, 95 FERC ¶ 61,384 at 62,438-39 (2001); *New York ISO*, 96 FERC ¶ 61,059 at 61,187 (2001). At the same time, it has emphasized that the stakeholder process must be meaningful, i.e., that stakeholders must have a full opportunity to provide advice and input before the RTO makes its decisions. *Alliance Cos.*, 94 FERC ¶ 61,070 at 61,304 (2001). Several state commissions have urged that a similar mechanism be implemented to provide state commissions an opportunity to communicate with and advise the RTO. See, e.g., "*Comments of the New England Conference of Public Utilities Commissioners on Mediation Report*," Regional Transmission Organizations, Docket No. RT01-99 at 8-9 (filed Oct. 5, 2001). This position is consistent with the Commission's recognition in Order No. 2000 that state regulators have a special role in ensuring that the wholesale markets are fully competitive. *See* Order No. 2000, FERC Stats. & Regs., Regs. Preambles ¶ 31,089 at 31,213 (1999).

The use of a regional siting advisory committee to consult with the RTO would serve a purpose similar to the stakeholder and state commission consultative process. State siting authorities would retain their decisionmaking obligations, but would benefit from participation in an advisory process that exposed them, not only to RTO transmission plans, but to the siting issues confronting neighboring states. The RTO would benefit from consultation with siting authorities at the planning stage (i.e., before making filings with the relevant agencies), while there remains an opportunity to develop a regional approach that is sensitive to local considerations.

5. What are your views about the independence of the RTO structures currently proposed in the Midwest region?

Response:

See Response to Question No. 1. Several of the state commissions joining in this letter have also addressed the issue in a recently filed protest to the Alliance/National Grid filing in Docket No. RT01-88-012. See Joint Protest of the State of Michigan, Michigan Public Service Commission and the Oklahoma Corporation Commission in Docket No. RT01-88-012, filed on November 21, 2001.

6. Do you have any other suggestions or advice as to how the FERC should proceed in its efforts to complete RTO formation in the Midwest?

Response:

The Midwest State Commissions have three suggestions. First, the most important action the Commission can take to advance the process is to provide prompt guidance on the questions it has posed. This will remove uncertainty in the market and facilitate decisionmaking by potential RTO participants. Second, the pace of the Commission's efforts in particular regions should be driven by the circumstances it finds. Where, as is the case in the Midwest, there is a broad regional consensus among state regulators to move forward with a single RTO, the Commission should direct its efforts and resources to those regions. Third, while the Midwest State Commissions seek no ongoing veto power over RTO decisions (such power being inconsistent with RTO independence), the Commission should establish an institutionalized role for the states in overseeing the RTO. The structure should provide a permanent place and role for states, distinct from that of stakeholders, regarding all issues important to the states, including interconnection, tariffs, congestion management, etc. In this regard, the Midwest State Commissions endorse the need for a special state commission advisory role reflective of the fact that, unlike stakeholders, state commissions have specific statutory and regulatory responsibilities to fulfill.

Finally, the Midwest State Commissions laud the Commission's decision to modify its ex parte rules to permit greater communication between itself and state commissions. This, the Midwest State Commissions believe, will enhance the process to the benefit of the public interest.

Respectfully submitted,

STATE OF MICHIGAN,
MICHIGAN PUBLIC SERVICE COMMISSION

By their counsel:

Harvey L. Reiter

David D'Alessandro
Harvey L. Reiter
Special Attorneys General
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1150 18th Street, NW, Suite 800
Washington, DC 20036
(202) 785-9100

Jennifer M. Granholm,
Attorney General of the State of Michigan
David A. Voges (P25143)
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Patricia S. Barone (P29560)
Assistant Attorneys General
6545 Mercantile Way, Suite 15
Lansing, MI 48911-5984
(517) 334-7650

And on behalf of the

Arkansas Public Service Commission,
Kentucky Public Service Commission,
Iowa Utilities Board,
North Dakota Public Service Commission,
Oklahoma Corporation Commission
Pennsylvania Public Utility Commission,
Public Service Commission of Wisconsin,
Virginia State Corporation Commission

November 30, 2001

February 16, 2004

Members of the MISO Board of Directors
and James P. Torgerson, President and CEO
Midwest Independent Transmission System Operator
701 City Center Drive
Carmel, Indiana 46032

Dear Members of the MISO Board and Jim,

Enclosed with this letter is a copy of a Memorandum of Understanding entered into by each of the major utilities in the Wisconsin and Upper Peninsula of Michigan System (WUMS) sub-region of MAIN strongly supporting a deferral of the MISO Day 2 Market in Wisconsin and simultaneously committing to pursue a very significant construction program to remedy the WUMS status as a load pocket. The MOU has been endorsed by the Customers First! Coalition (CFC), with the understanding that there will be an open and public planning process that addresses all needs. CFC includes among others, the Wisconsin Industrial Energy Group, the Citizens Utility Board, AARP, National Federation of Independent Businesses-Wisconsin, the Wisconsin Merchants Federation, the IBEW, RENEW Wisconsin, the Municipal Electric Utilities of Wisconsin and the Wisconsin Federation of Cooperatives and Dairyland Power Cooperative. The MOU also has been strongly endorsed by the Wisconsin Paper Council. In short, Wisconsin electric utility stakeholders are united.

On behalf of our utilities and our customers, we urge the MISO Board to work with the WUMS utilities to implement the MOU in a way that will meet the needs of Wisconsin and the Upper Peninsula of Michigan and the other members of MISO. We are not seeking to delay the market for others. Nor do we wish to shift costs to anyone. We believe that these objectives can be accomplished if we work together.

The commitments in the MOU are strong and real and the market deferral we seek is tied to a specific infrastructure improvement program. We recognize that it is our responsibility to meet the five-year deadline.

The bottom line is that the Day 2 Market presents unacceptable risk to residents and businesses in Wisconsin and the Upper Peninsula of Michigan because we lack the infrastructure necessary to make the market work. We are committed to putting the necessary infrastructure in place, as the MOU demonstrates. We are not aware of any other area within MISO or outside MISO with as ambitious a construction program. We are not willing to unnecessarily jeopardize Wisconsin's economic development and to have our customers pay twice, while we fix our system.

LGE/KU Exhibit 3

February 16, 2004
Page Two.

The WUMS utilities have been strong supporters of MISO from the beginning and we continue to be strong supporters. We need your cooperation now to provide us the opportunity to enter the market with the infrastructure necessary for the benefits of the market to be actually realized in our state. We are confident that if each of you were in our position you would be asking for the same consideration.

Thank you for your help.

Sincerely,

William Harvey
President and Chief Operating Officer
Alliant Energy Corporation on behalf of
Wisconsin Power and Light Company

Gary Wolter
President and Chief Executive Officer
Madison Gas & Electric Company

Gale Klappa
President and Chief Executive Officer
W.E. Energies

Larry Weyers
President and Chief Executive Officer
WPS Resources Corporation

Roy Thilly
President and Chief Executive Officer
Wisconsin Public Power Inc.

REVISED MEMORANDUM OF UNDERSTANDING BETWEEN WE ENERGIES, WISCONSIN POWER & LIGHT COMPANY, WISCONSIN PUBLIC SERVICE CORP., MADISON GAS & ELECTRIC CO. AND WISCONSIN PUBLIC POWER INC. ON MISO DAY 2 MARKET

We support competitive wholesale electric markets, but we also recognize that Wisconsin's transmission infrastructure is inadequate to support the proposed MISO Day-2 market at this time without exposing Wisconsin utilities and their customers to substantial risk. The parties are committed to developing and implementing a plan to improve our infrastructure so that Wisconsin can join the regional market on a date certain.

1. We will seek a delay in implementation of the Day 2 Market in the Eastern Wisconsin and Upper Peninsula of Michigan System (WUMS) until a specific date at which time WUMS will enter the MISO Day-2 Market. The date of entry will be five years from January 1, 2005; that is, January 1, 2010. This date of entry is based on major infrastructure improvements, many of which are already underway. Others are in the planning stages and will require both public input and Public Service Commission approval. These projects are listed on Attachment #1 to this Memorandum.

   During this five-year period, we also will support construction of additional transmission facilities by the American Transmission Company (ATC) to the extent needed to provide all utilities within the ATC footprint with reasonable and comparable access to the market outside of the ATC footprint and to eliminate significant constraints between what are now the control areas within ATC, so that WUMS will not enter the Day-2 Market as a load pocket. We will reach agreement on specific import capability objectives for each interface and specific objectives for elimination of internal constraints on an expedited basis, but no later than May 1, 2004. ATC will complete a plan with proposed deadlines to achieve these objectives, together with an assessment of costs by August 1, 2004 and will work collaboratively with other stakeholders to obtain needed input and support and to obtain prompt approval by the PSC of this plan and these objectives. Individual projects consistent with the plan will be developed using a public collaborative planning process and be subject to state siting and approval requirements, as well as compliance with the MISO planning process. Each utility will employ the resources necessary in connection with an agreed upon strategy to enable ATC to accomplish the access objectives that are agreed upon in a worst-first priority basis. The parties recognize that it will be essential to include in the MISO plan the fixes necessary on the adjacent systems for reasonable Wisconsin access and obtain needed commitments from others for those fixes, so Wisconsin's access needs can be met.

2. We will participate in cooperation with the MAPP area utilities in development of a mutually beneficial MISO-West proposal, including use of a tariff administered by MISO-West that generally tracks the TRANSlink highway/zonal model and does not disadvantage ATC and its customers.

3. We will commit to examine and implement on an expedited basis means to achieve significant efficiency and other benefits within WUMS prior to implementing the proposed Day-2 Market, subject to agreement on the details of any proposal such that no utility or its customers is materially disadvantaged. In this regard, ATC, in consultation with its customers, shall develop a detailed plan to move to a single ATC control area with centralized dispatch of excess supply. This may be done in two stages, if necessary. The

first stage, to be accomplished no later than 18 months from January 1, 2004 would include internal re-dispatch by ATC similar to today. The second stage would occur six months later and include implementation of a centralized dispatch of excess supply. Each utility will retain the benefits and burdens of its resources, the ability to buy and sell into and out of WUMS and to do bilateral transactions within WUMS. ATC also will commit to employ its best efforts to identify and implement means within the next six months to address the comparable access concerns of all LSEs, consistent with ATC's founding documents.

4. We will work together on an expedited basis to seek input and support from other Wisconsin and Michigan MISO stakeholders and PSC, MPSC, FERC and MISO acceptance of this plan.

Dated January 30, 2004
Revised February 9, 2004

Attachment #1

Wisconsin/Upper Peninsula Of Michigan

Currently Planned Major Transmission & Generation Facility Upgrades 2004 to 2010

No.	Project	Type	Miles/kV Size	Projected Cost (Millions)	CPCN/CA Date	Projected Completion Date
		Major Transmission*				
1	Arrowhead Weston	New Transmission	250/345kV	$450	12/03	6/08
2	Northern Umbrella Plan	New & Rebuilt Transmission & Substations	50/345 kV 97/138 kV	$225	Various 2/04/3/05	Various 2004-2010
3	Southern Umbrella Plan	New & Rebuilt Transmission	16/345 kV 108/138kV	$295	Various 2005/2010	Various 2004/2012
4	Major "Access Project" Placeholder (IA to WI)	New Transmission (major 345 kV project plus additional lower voltage supporting projects TBD)	150/345kV	$300	Various	Various
	Totals**		466/345kV 205/138kV	$1,087		2010
		Major Generation				
				$T***/$G		
1	Riverside	Combined Cycle	603 MW	$63/$327	9/2002	6/2004
2	West Campus	Cogeneration Unit	150 MW	$35/$100	9/2003	6/2005
3	Sheboygan Falls	2- Combustion Turbine Generators	370 MW	$7/$150	2004	6/2005
4	Fox Energy	Combined Cycle Generation (only 370 MW expected in 2005; remaining unit in service unknown at this time)	670 MW	$14/$272	11/2002	6/2005
5	Port Washington I	Combined Cycle Generation Units	600 MW	$29/$150	12/2002	6/2005
6	Weston 4	New Base Load Coal Generation	550 MW	$108/$800	8/04	6/2008
7	Port Washington II	Combined Cycle Generation Units	600 MW	$0/$150	12/2002	6/2008
8	Elm Road I	New Base Load Coal Generation	650 MW	$82/$1,075	11/2003	6/2009
9	Elm Road II	New Base Load Coal Generation	650 MW	$64/$1,075	11/2003	6/2010
	Totals		4,843 MW	$402/$4,099		2010

Most transmission and generator costs are based on average costs for typical construction.

* The 2003 ATCLLC 10-Year Assessment (2003-2012) includes about $2.8 billion of transmission projects, the following are just the major projects from 2003 to 2010 and do not include many smaller projects.

** Does not include transmission associated with new generation, covered below

*** Based on most current Generation Interconnection and Transmission Service Study reports as of 2/6/04

Customers First!
Plugging Wisconsin In

February 10, 2004

Commissioner Burnie Bridge
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, Wisconsin 53707-7854

Commissioner Ave Bie
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, Wisconsin 53707-7854

Commissioner Robert Garvin
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, Wisconsin 53707-7854

Re: Customers First! Coalition's Comments on the Wisconsin Utilities' Memorandum of Understanding Regarding the Implementation of the MISO Day 2 Market

Dear Commissioners:

The Customers First! Coalition is an alliance of Wisconsin customer groups, municipal utilities, rural electric cooperatives, labor unions, environmental groups and one investor-owned utility. Our members are listed below. Since 1996 we have been providing input to policymakers and encouraging bipartisan consensus on Wisconsin's energy policy. We support a sequential, one-step-at-a-time approach to change in the electric industry and advocate for the interests of Wisconsin customers and users first.

We understand a Memorandum of Understanding (MOU) has been signed by the investor-owned utilities in eastern Wisconsin agreeing to the delayed implementation of MISO's Day 2 Market until the transmission constraints in Wisconsin and seams issues with ComEd can be resolved. We support and endorse this MOU with the following changes:

- The process to decide on the transfer capacity and improvements necessary to remedy Wisconsin's status as a load pocket and to plan transmission additions must be open and provide the opportunity for full public participation.

A Coalition to Preserve Wisconsin's Reliable and Affordable Electricity

608.286.0784
888.960.4778 toll free
fax 608.286.6174
P.O. Box 54
Madison, WI 53701
www.customersfirst.org

American Association of Retired Persons-Wisconsin • Citizens' Utility Board • Dairyland Power Cooperative • International Brotherhood of Electrical Workers-Local 2304 • International Brotherhood of Electrical Workers-Local 2150 • Madison Gas & Electric Company • Municipal Electric Utilities of Wisconsin • National Federation of Independent Business-Wisconsin • RENEW Wisconsin • Wisconsin Alliance of Cities • Wisconsin Coalition of Energy Consumers • Wisconsin Community Action Program Association • Wisconsin Electric Cooperative Association • Wisconsin Federation of Cooperatives • Wisconsin Merchants Federation • Wisconsin National Farmers Organization • Wisconsin Public Power Inc. • Wisconsin Retired Educators' Association • Wisconsin Towns Association

- The planning process will be consistent with the Public Service Commission of Wisconsin's (PSCW) enhanced Strategic Energy Assessment and will include PSCW review and approval of the plan.

- All Certificate of Authority, Certificate of Public Convenience and Necessity and other statutory requirements will apply.

- The process must be an integrated plan which addresses the needs of Western Wisconsin as part of a non-discriminatory statewide approach, and must include the participation of Western Wisconsin utilities.

- The retail customer groups cannot endorse wholesale competition per se without understanding the specific model and a clear determination of net benefits for retail customers.

With the above changes, the Customers First! Coalition strongly supports the MOU. Please contact me if you would like to further discuss this issue.

Sincerely,

Lee Cullen

Lee Cullen, Attorney for the Customers First! Coalition

cc: Gary Wolter, Madison Gas & Electric Company
Roy Thilly, Wisconsin Public Power Inc.
Gale Klappa, WE Energies
Larry Weyers, Wisconsin Public Service Corp.
Bill Harvey, Alliant Energy
Jose Delgado, American Transmission Company
Customers First! Coalition's Executive Committee

WISCONSIN PAPER COUNCIL
250 N. GREEN BAY ROAD
P.O. BOX 718
NEENAH, WI 54957-0718
PHONE: 920-722-1500
FAX: 920-722-7541
www.wipapercouncil.org

February 12, 2004

Commissioner Burnie Bridge
Public Service Commission of Wisc.
P.O. Box 7854
Madison, WI 53707-7854

Commissioner Ave Bie
Public Service Commission of Wisc.
P.O. Box 7854
Madison, WI 53707-7854

Commissioner Robert Garvin
Public Service Commission of Wisc.
P.O. Box 7854
Madison, WI 53707-7854

Dear Commissioners:

The Wisconsin Paper Council is the trade association representing the pulp and paper industry in the state.

We support a sequential, logical and cost/benefit approach to electric industry transformation that yields quantifiable benefits for the paper industry and other retail customers.

We have reviewed the Memorandum of Understanding signed by the investor-owned utilities in eastern Wisconsin regarding delaying implementation of MISO's Day 2 market until transmission system constraints within Wisconsin and seams issues with ComEd are resolved.

The Wisconsin Paper Council wants to go on record in support of the MOU's provisions.

Please contact me if you have any questions regarding this letter.

Sincerely,

Earl Gustafson

Earl Gustafson
Energy/Project Manager

cc: Roy Thilly, Wisconsin Public Power Inc.
Bob Domrois, Chair, WPC Energy Steering Committee

February 3, 2004

The Honorable George W. Bush
President of the United States
The White House
1600 Pennsylvania Avenue, MW
Washington, DC 20500

Dear Mr. President:

As chief executives of Southern states, would like to express our sincere appreciation of you working with Congress to protect electricity consumers from FERC's radical and unprecedented electricity restructuring proposals. However, as a region we remain extremely concerned that FERC is aggressively moving forward with a series of actions that will coerce RTO participation, preempt state law, and exceed the commission's own statutory authority. In fact, FERC stepped up these efforts as soon as the Energy bill failed to pass the Senate at the end of the session.

In November, FERC issued a preliminary order directing the Eastern region of American Electric Power Company to join the PJM interconnection over state objection, particularly the states of Kentucky and Virginia. In that order, FERC declared that section 205(a) of PURPA provides it with the legal authority to override state law and mandate that a utility join an RTO, even though PURPA was written 20 years before the concept of an RTO came into existence. We are concerned that after a final order is issued in this case, FERC could use this decision as precedent to preempt any state law requiring a finding of net public interest on transmission issues and to mandate its own vision and definition of an RTO throughout the country. In December, FERC announced it intends to renew its focus on the controversial Supply Margin Assessment proposal – a market-based pricing policy that would essentially prevent large vertically integrated electric companies from obtaining market-based rates (and provide ratepayer credit) for excess generation that they do not use to serve their bundled retail load, unless those companies join an RTO. This proposal appears to be an attempt to coerce the utilities in the Southern region to join RTOs.

Recent FERC orders and public pronouncements also appear to signal that FERC has concerns with the way that state-jurisdictional, rate-regulated and vertically integrated electric utilities plan for and purchase the generation requirements for their bundled retail load. Since most of the electric utilities in our region are vertically integrated and are required by our state statutes to build or buy generation at the lowest possible cost to serve their rate-regulated retail customers, it would be of great concern if these recent orders and pronouncements indicate a FERC effort to dismantle our state-regulated system. FERC has also indicated it may issue rules mandating reliability standards, even though FERC lacks clear statutory authority to do so. Only state utility commissions currently have statutory authority to ensure and enforce reliable electric service. We recognize the need for mandatory reliability standards. However, we believe Congress is the appropriate body to institute the mandate and the North American Electricity Reliability Council is the proper entity to implement mandatory standards.

LGE/KU Exhibit 4

These recent FERC actions signal a clear attempt by FERC to utilize creative mechanisms to force electric utilities to join RTOs regardless of the economic merit or benefits to ultimate ratepayers in the affected states. Also, by virtue of requiring the RTO to fit FERC's particular definition, we view these actions as a backdoor attempt by FERC to implement its Standard Market Design (SMD) proposal without regard to regional differences or regional benefit. FERC appears to be engaged in a forced march towards implementing its vision of national competition and is determined to replace guaranteed cost-based rates for generation with market-based prices for generation and transmission service, regardless of the increased costs to consumers.

The Southern governors remain adamantly opposed to these and other efforts by FERC to force risky and untested electricity restructuring proposals on regions of the country that have chosen to remain rate-regulated with vertically integrated utilities that provide reliable, efficient, and low-cost electric service. It is a fact that our regulatory system is responsible for our low rates, lack of volatility, and lack of reliability concerns. We have made prudent investments in infrastructure which, in addition to providing the best possible electric service to our citizens, contributes to our ability to attract industry to our region and provide employment and enhanced quality of life opportunities for our residents. It is not only unfair, but economically very dangerous, to ask Southern states to be subjected to FERC's academic electricity competition models. It is our regulatory model, not FERC's, that has and will continue to result in low rates, appropriate infrastructure investment, and reliable electric delivery service.

As debate resumes on the comprehensive energy bill, we ask that you continue to work with members of Congress to support an energy bill that contains provisions which will protect the availability of transmission service for native load customers, provide that participation in RTOs is voluntary so that states can ensure net cost-effectiveness, establish the requirement for "participant funding" of transmission investment for those states that desire that pricing approach, and impose at least a three-year delay of SMD. We strongly support these provisions and urge you to work with Congress to preserve them in the energy bill.

Sincerely,

Mike Huckabee, Arkansas	Sonny Perdue, Georgia

Bob Holden, Missouri

Mark Sanford, South Carolina

Haley Barbour, Mississippi

Michael F. Easley, North Carolina

Kathleen Babineaux Blanco, Louisiana

Bob Wise, West Virginia

Ernie Fletcher, Kentucky

cc: The Honorable Richard B. Cheney Vice-President of the United States
The Honorable Spencer Abraham, Secretary of Energy

February 3, 2004

Sabstitu
Signe
copy

The Honorable Pete Domenici
Senate Energy and Natural Resources Committee
364 Dirksen Senate Office Building
Washington, DC 20510

The Honorable W.J. "Billy" Tauzin
House Energy and Commerce Committee
2125 Rayburn House Office Building
Washington, DC 20515

Dear Chairmen:

As chief executives of Southern states, would like to express our sincere appreciation of you working with Congress to protect electricity consumers from FERC's radical and unprecedented electricity restructuring proposals. However, as a region we remain extremely concerned that FERC is aggressively moving forward with a series of actions that will coerce RTO participation, preempt state law, and exceed the commission's own statutory authority. In fact, FERC stepped up these efforts as soon as the Energy bill failed to pass the Senate at the end of the session.

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Holstein

LGE #4

service. We recognize the need for mandatory reliability standards. However, we believe Congress is the appropriate body to institute the mandate and the North American Electricity Reliability Council is the proper entity to implement mandatory standards.

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Michael F. Easley, North Carolina

Kathleen Babineaux Blanco, Louisiana

Bob Wise, West Virginia

Ernie Fletcher, Kentucky

cc: The Honorable Richard B. Cheney Vice-President of the United States
The Honorable Spencer Abraham, Secretary of Energy

MISO's

Benefits to LG&E and KU Customers Through 2010

Costs Through 2010:				
	Schedule 10 Costs	**$**	**43,900,000**	
	Schedule 16 Costs	**$**	**8,600,000**	
	Schedule 17 Costs	**$**	**27,600,000**	
Total Costs		**$**	**80,100,000**	
Benefits Through 2010:				
	Net Energy Market Benefits	**$**	**152,100,000**	
	Exit Fee	**$**	~~38,300,000~~	38,200,000
	Merger Surcredits	**$**	~~143,800,000~~	125,800,000
	Reliability Benefits	**$**	**16,200,000**	
Total Benefits		**$**	~~350,400,000~~	332,400,000
NET BENEFITS		**$**	**270,300,000**	252,300,000

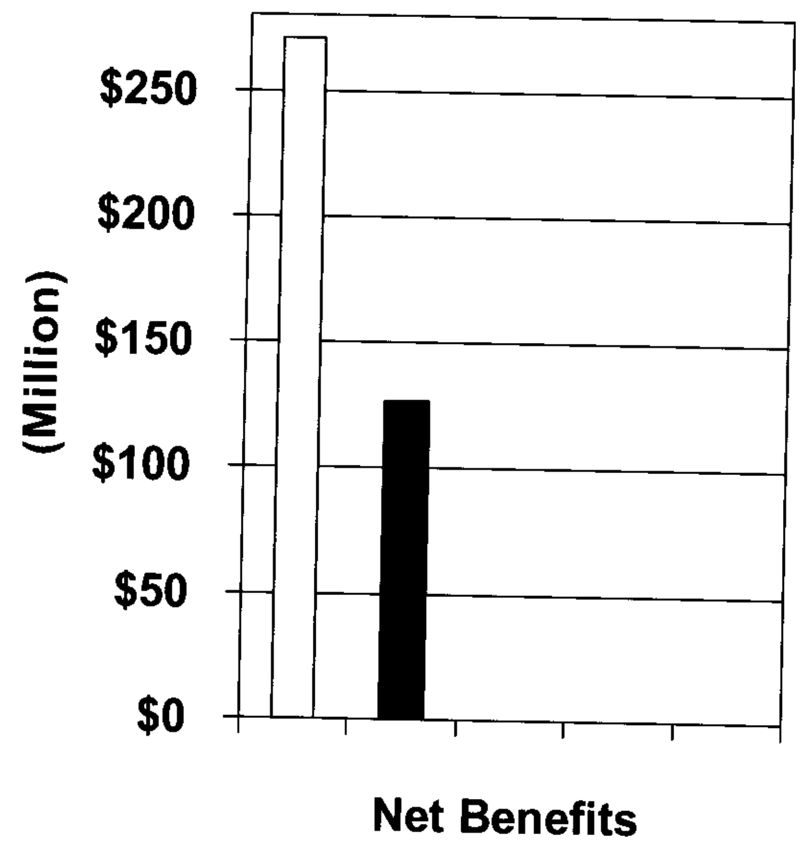
Michael Holtan
2/27/04

Source: Attachment to
KPSC No. 6(a)

LGE/KU Exhibit 5

Merger Benefits $143.8 M

• Net Benefits	$270.3
• Merger Benefits	($143.8)
NET BENEFITS	$126.5

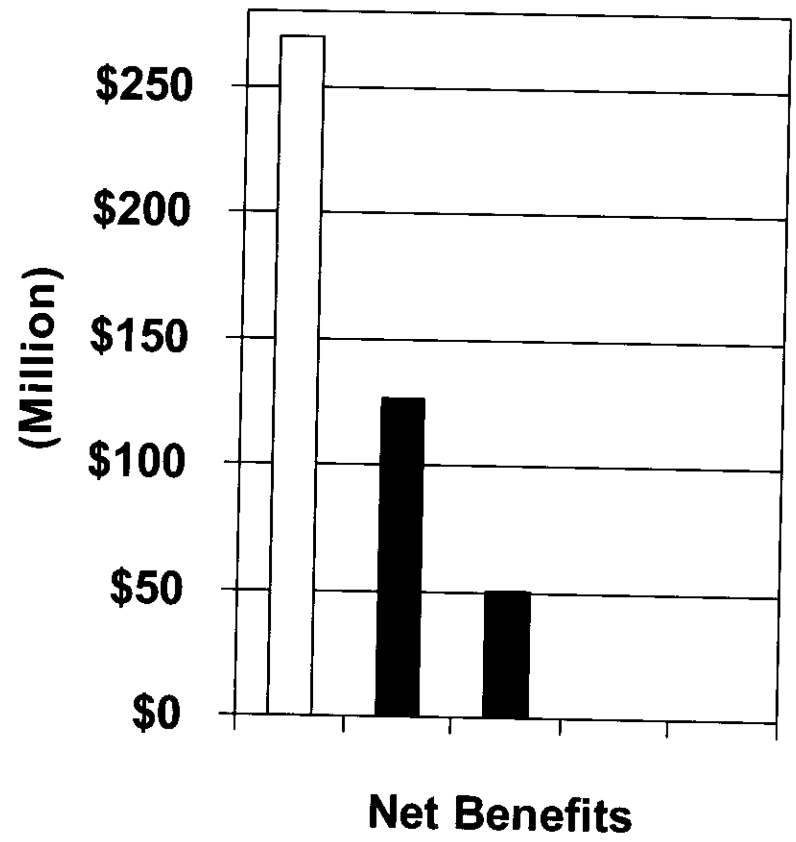


Additional Transmission Revenue $ 76.1 M

Additional Transmission Revenue

MISO Member	$ 21.8
Standalone	($ 9.1)
	$ 12.7
	x 6 yrs
	$ 76.1

• Net Benefits	$126.5
• A.T.R.	($ 76.1)
NET BENEFITS	$ 50.4

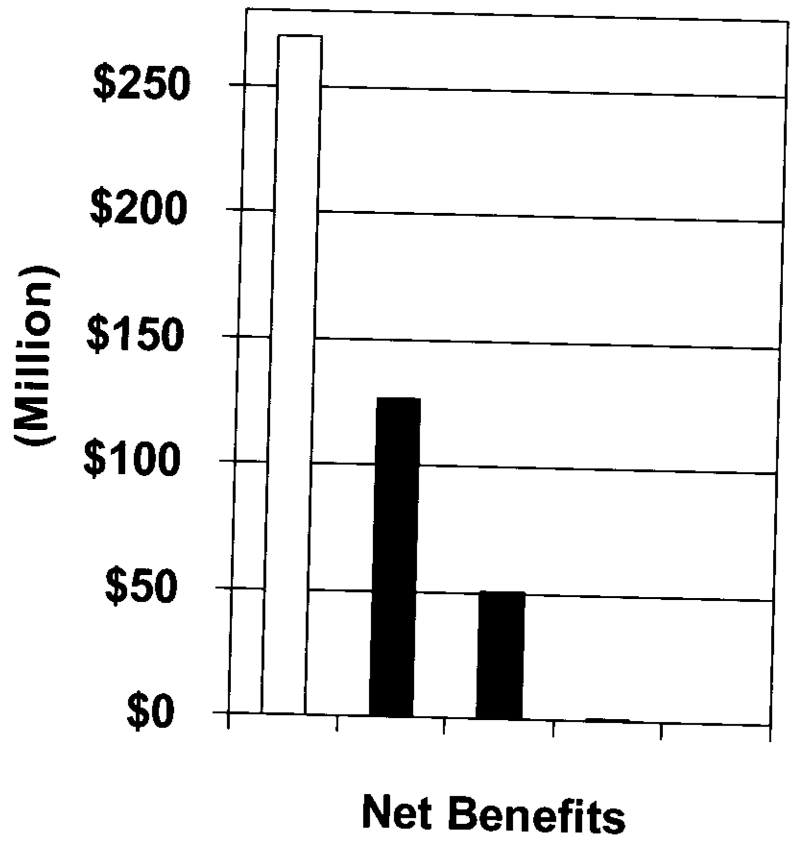


OSS Margin $ 50.1 M

MISO Member	$ 27.1
Standalone	($ 13.4)
	$ 8.35 M
	x 6 yrs
	$ 50.1 M

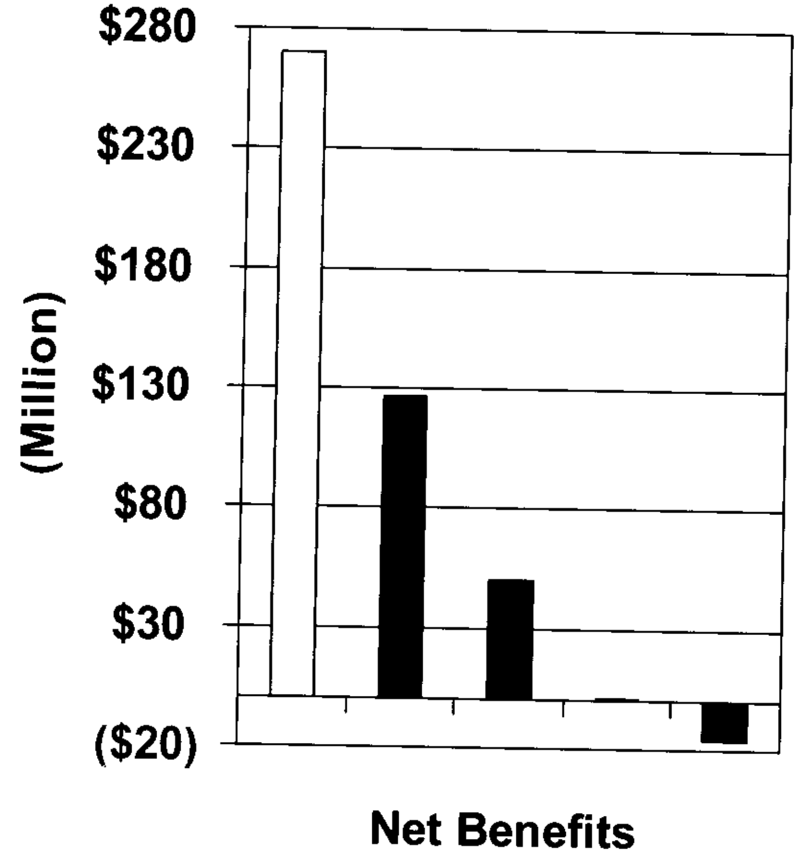
★ 2002 OSS (MWH) Scaled Backed by 30%
★ $3/MWH Transaction Cost

• Net Benefits	$ 50.4
• OSS Margin	($ 50.1)
NET BENEFITS	$ 0.3



Reliability Benefits $ 16.2 M

	$ 2.7
	x 6 yrs
	$ 16.2 M
• Net Benefits	$ 0.3
• Reliability Benefits	($ 16.2)
NET BENEFITS	($ 15.9)



TESTIMONY OF JAMES P. TORGERSON
PRESIDENT AND CHIEF EXECUTIVE OFFICER
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
BEFORE THE U.S. SENATE COMMITTEE ON ENERGY
AND NATURAL RESOURCES
FEBRUARY 24, 2004

Good morning, Mr. Chairman and members of the Committee. My name is James P. Torgerson. I am the President and Chief Executive Officer of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). The Midwest ISO was formed in 1998. It is the first entity found by the Federal Energy Regulatory Commission ("FERC") to be a Regional Transmission Organization ("RTO"). The Midwest ISO did not originate from a legislative mandate or against the backdrop of a tight power pool, but from voluntary action.

The Midwest ISO's region covers portions of fifteen states and the Canadian province of Manitoba. Of relevance to your inquiry here, we act as a Reliability Coordinator for two sets of companies: one who are our members and a second set in the Mid-Continent Area Power Pool (MAPP) region that have not transferred control of their transmission systems to the Midwest ISO. As Reliability Coordinator, the Midwest ISO monitors, plans, conducts analyses regarding the high voltage grid and communicates with the Control Areas in our region who have the primary control capabilities to open and close transmission circuits and to redispatch generation. Three of the more than 30 companies within our reliability coordinator territory suffered outages in the blackout of August 14, 2003.

Mr. Chairman, as you know your letter of invitation to this hearing asked us to respond to the recommendations contained in North American Electric Reliability Council's ("NERC") February 10th Report on the August 14th blackout. The recommendations which most directly apply to the Midwest ISO are found at Attachment A Section (B) to Recommendation 1 of the NERC Report which is included at the end of my testimony. I would like to specifically address each one of the NERC recommendations as they apply to the Midwest ISO.

LGE/KU Exhibit 6

Corrective Action #1 - Reliability Tools

In order to meet and exceed our duties as a Reliability Coordinator, the Midwest ISO utilizes a variety of tools, which we continue to upgrade and enhance as new capabilities become available. Those tools were already in the process of being upgraded prior to the August 14th events, but those events have prompted the acceleration and further expansion of those enhancements.

In August 2003, the Midwest ISO was using two primary tools for reliability coordination: a status change alarm log and a flowgate monitoring tool with a static contingency analysis tool. While this tool set was substantial, it left us highly dependent on information from Control Areas within our region for the most accurate assessment of the status of the grid. When incorrect, incomplete or no information was provided, we were at risk of being unaware of significant operating events. Our systems also lacked extensive visibility into our neighboring systems, and as with our own region, were dependent on others for some of the data that was used to run the tools.

Prior to August 2003, the Midwest ISO was already working to improve its capabilities. We were developing a State Estimator to model the current status of the transmission network and to use as a basis for contingency analysis and other real-time monitoring tools. At that point in time, we had already modeled over 60,000 data measurement points, but the model was not stable enough to be used as a primary reliability-monitoring tool. Since that time, we have added an additional 28,000 measurement points and stabilized the model. On December 31, 2003 this tool was promoted to be the primary tool for monitoring the real-time status of the transmission system. This reliability tool is a comprehensive model of the transmission network. It monitors and measures the status of all transmission lines and transformers over 230 kV (as well as all others identified as being critical to system operations) and the status of all generating units in our region. Our model also includes the first control area adjacent to the Midwest ISO area for most of our neighboring systems, and we are working to finish the modeling into all of the other neighboring control areas. The State Estimator runs every 90 seconds and provides a detailed updated view of the entire system.

We also have a contingency analysis tool that runs on every third run of the State Estimator. This tool analyzes approximately 5,000 different potential contingencies identifying potential problems on the system. Our modeling personnel continue to work to improve these tools by working with Control Areas both within our region and in our neighboring systems to improve the information and integration of the system. We are also working to improve the speed of these tools. Our goal is to significantly improve the solution rate while we also increase the number of points being monitored.

The identification and management of transmission and generation outages is a critical part of any reliability coordination effort. Within the Midwest ISO region, all outage information is received from the equipment owner via a real-time data exchange. This information is automatically incorporated into the State Estimator model. The Midwest ISO is continuing to work to increase the availability of real-time outage information from neighboring systems. In August 2003, data from neighboring systems was all received via an industry standard interface that is not a real-time exchange tool. Through the joint operating agreement recently executed with PJM, our neighboring RTO, our two companies have worked to create the infrastructure for the real-time exchange of operating data, including outage data between regions. We expect to be exchanging real-time outage information with PJM by May of this year. We are attempting to negotiate the same real-time exchange of outage information with our other neighbors.

In order to better utilize the vast amounts of data available to our reliability coordinators, a great deal of effort has gone into developing tools to sort out the most critical data and provide alarms properly identifying the significance of that data. Since August 2003, the Midwest ISO has substantially upgraded its alarming systems. We have increased the identification and integration of information through increased alarming levels for change of status Megawatt, MegaVar and kV limit measurements. We have also improved the presentation of the alarms through the use of increased alarm grouping, color-coding and limit threshold adjustments. The Midwest ISO is continuing to explore and evaluate additional improvements to our alarming capabilities.

We have taken considerable efforts to provide redundancy and backup for our reliability tools. These efforts have several dimensions. First, all our reliability tools have at least one other tool that can provide similar information. For example, if our State Estimator became unavailable for any reason, we would use our flowgate-monitoring tool as an alternate means of monitoring the system in real time. And if our contingency analyzer was unavailable, we could also use our flowgate-monitoring tool as the backup.

Also, each of our computerized reliability tools has a redundant version (software and hardware) on site and in the event of a failure of the primary system; the redundant system would automatically take over its operation. Our building and computer room electrical supply and communication systems have built in redundancy as well. Finally, in the event of the complete loss of either our Carmel, Indiana or our St. Paul, Minnesota facility, they are backed up at an alternate location. The Carmel facility has a permanent back-up site near downtown Indianapolis, and the Carmel facility provides backup for the St. Paul facility.

We believe the steps necessary to implement this NERC recommendation have been completed.

Corrective Action #2 - Visualization Tools

In order to rapidly analyze and respond to system anomalies, it is critical to provide our reliability coordinators with tools to quickly visualize the portions of the system where the anomaly exists. Prior to August 2003, the Midwest ISO was highly dependent on input from the Control Areas in our region in order to visualize problems. Evaluation of the blackout events made it clear that this dependency raised concerns. The Midwest ISO has taken steps to eliminate that dependency and provide our operators with the tools to rapidly visualize system problems. Since August 2003, we have developed and implemented visualization tools that allow our operators to monitor the system in greater detail and on a wider geographic basis. As operating situations dictate, the operator can then narrow his view to see smaller and smaller segments of the system down to and including one-line electrical schematic diagrams of individual substations to better identify specific problems.

The reliability coordinators now have an overview tool that allows them to monitor the Midwest ISO transmission system and surrounding areas on a real-time basis. This includes all 230 kV and higher transmission facilities along with all critical underlying facilities of 100 kV and above. The real-time overview includes information on real-time megawatt and reactive power values, voltage profiles and outage indications. As the operator needs additional detailed information, he can automatically access more detailed information on a specific area. This information can be displayed in a simple one-line electrical schematic diagram.

As part of this visibility tool enhancement project, the Midwest ISO also upgraded the video projection system in our Carmel, Indiana facility. The video projection system provides the ability for a large amount of real-time, dynamic, visual information to be displayed and viewed by several people in the control center simultaneously. The upgrade program included the addition of over 20 new video projection units more than doubling the display area in the control room.

We believe these enhancements go beyond the recommendations made in the NERC report.

Corrective Action #3 - Training

We believe that training is as important to providing reliable services as adequate tools. Prior to August 2003, the Midwest ISO had focused on recruiting experienced and skilled operators to staff our control room. The blackout event highlighted the need to increase our training efforts. The Midwest ISO has developed a comprehensive training plan that we are currently implementing. By

June 30th, each of our reliability coordinators will have completed at least five days of system emergency training as recommended. That requirement will continue on an annual basis and will also be developed to include performance assessments of each reliability coordinator in a training mode. This training will consist of a combination of activities including the following:

- Regional Emergency Response Drills – The Midwest ISO will participate in regional drills with MAPP, Mid-America Interconnected Network, Inc. ("MAIN") and East Central Area Reliability Council ("ECAR"). These drills will also involve member control area operators and in some instances other reliability coordinators such as PJM. The Midwest ISO will assess our reliability coordinators participation in the drills through observations and in debriefing sessions following the drills.
- Table Top Emergency Drills – The Midwest ISO will use a series of one-day tabletop drills that will involve varying combinations of Midwest ISO staff and control area operators from our membership. These drills will be fact specific and scenario driven to test staff's performance in response to hypothetical problems. The Midwest ISO staff's performance will be evaluated and appropriate actions taken.
- Emergency Training on a Training Simulator – The Midwest ISO is developing training scenarios for use with our training simulator. The initial scenarios will involve two-day sessions where individual operator performance can be assessed and compared to other operators working on the same simulations. This training will occur during the 2nd quarter of 2004.
- Operating from Back-Up Control Center Drills – The Midwest ISO will train our operators on a range of emergency conditions including those that involve the loss of our primary control center with the accompanying need to transfer operations to our back-up facilities in a rapid manner.
- Training on Emergency Operating Guides – All Midwest ISO reliability coordinators are required to review and understand all standing, temporary and emergency operating procedures applicable to their jobs. This self-study is reviewed with the operators by their supervisors on a regular basis.
- Emergency Communications and System Restoration – This is a three-day training course that focuses on communication skills, critical thinking (including the application of those skills to system operations) and restoration activities. Participants in this training will be assessed through an exam provided at the end of the course.

This recommendation will be met by the June 30, 2004 deadline.

Corrective Action #4 - Communications

Following the events of August 14th, the Midwest ISO reevaluated our communications protocols and procedures and implemented significant improvements, including:

- Working jointly with our membership to develop and implement an Emergency Response Procedure directive that clearly states the definition of a system emergency, the criteria for a system emergency and the emergency actions that will be taken to resolve such an emergency.
- We also implemented our Conservative System Operating Procedures that defines events and conditions that warrant implementing more conservative system operating procedures and lists the procedures, and communications needed to implement those procedures. In addition, our joint operating agreement with PJM obligates both parties to operate to the most conservative limit on all jointly monitored flowgates and equipment. This condition allows both companies to assure reliable operation of our systems.
- Midwest ISO reliability coordinators are obligated to post critical outage information to the NERC communication systems to update neighboring Reliability Coordinators.

We believe the steps necessary to implement this recommendation have been completed.

Corrective Action #5 - Operating Agreements

Transmission system reliability depends on the ability of the Reliability Authority to not only identify problems and rapidly design solutions, but also on the authority to order users of the grid to implement corrective measures. As recommended, we have also reviewed our authority to direct corrective action over those parties to whom we provide reliability coordination services. These entities fall into five categories summarized below:

- Transmission owning members of the Midwest ISO – Our authority over this segment is clear and reinforced by several sources. First, FERC Order Nos. 888[1] and 2000[2] make clear the role of the ISO/RTO in providing reliability (security) coordination to its members. Additional FERC regulations on the operational authority and short-term reliability authority of RTOs further reinforce that authority.[3] In addition, the Midwest ISO

[1] *Order No. 888, 61 Fed. Reg. 21,540, FERC Stats. & Regs. ¶31,036 (1996).*
[2] *Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶31,089 (1999) (Order No. 2000), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. &Regs. ¶31,092 (2000) (Order No. 2000-A).*
[3] *18 CFR §35.34 (j)(3) and (4) (2003).*

Transmission Owners Agreement and the Midwest ISO Open Access Transmission Tariff also both provide explicit authority for reliability coordination.

- Independent Transmission Companies (ITCs) who are members of the Midwest ISO – Our sources of authority over this category is very similar to that shown above, and is addressed in Appendix I to the Transmission Owners Agreement that deals specifically with ITCs.
- Non-transmission owning users of the transmission system, including non-member generators - Our primary source of authority in this instance is the FERC approved Open Access Transmission Tariff, which contains specific requirements to follow the direction of the Midwest ISO to relieve loading problems, and provides for monetary penalties in the event of failure to comply.
- Companies not members of the Midwest ISO, to whom the Midwest ISO provides reliability services under contract. This category currently includes members of MAPP that are not members of the Midwest ISO. Under this category, we have a contractual arrangement with the MAPP reliability region of NERC (and prior to October, 2003 with the ECAR reliability region) to fulfill their contractual obligations with their members. We do not have a direct contractual relationship with the Control Areas themselves and we obtain our authority through MAPP's relationship with its membership.
- Canadian Province – The Midwest ISO has a coordination agreement with Manitoba Hydro under which we act as Reliability Coordinator for their transmission facilities. The agreement specifically lists the responsibilities of the Midwest ISO as Reliability Coordinator. However, it does not obligate Manitoba Hydro to follow the directions of the Midwest ISO. Due to the unique international relationships involved in this contract and the nature of Manitoba Hydro as a Canadian Crown corporation, they are unable to make this contractual commitment. However, this agreement is the most comprehensive of its type between Canadian and U.S. companies within the industry. The working relationship between the companies has been outstanding and Manitoba Hydro has always voluntarily complied with our directions as their Reliability Coordinator.

In addition, the Midwest ISO will soon file with the FERC a "Reliability Charter" with many Midwest entities that identifies in specific detail the roles and responsibilities of each entity to maintain system reliability. We are also planning to work with the NERC Operating Committee in its efforts to revise the operating policies and procedures to ensure reliability coordinator and control area functions, responsibilities, and authorities are completely and unambiguously defined, as described in NERC recommendation 9.

We believe the steps necessary to implement this recommendation have been completed.

Mr. Chairman, the Midwest ISO fully supports the remaining NERC recommendations contained in the Blackout Report. I would like to comment on some of the other specific recommendations. Recommendation 3 addresses an improved audit process so that all Control Areas and Reliability Coordinators will be reviewed on a three year cycle. While the recommendation proposes to audit only 20 of the highest priority entities by June 30, the Midwest ISO would support increasing the number of first year audits. We would also support NERC adopting a policy stating that an entity that commits a significant or repeated violations of reliability standards will be placed on an annual audit cycle until NERC is satisfied that the problems have been corrected.

The Midwest ISO believes that Recommendation 4 concerning vegetation management should not merely rely on reporting vegetation related outages but should establish minimum line clearance standards to avoid contacts in the first place. This is an area where Reliability Coordinators like the Midwest ISO must continue to rely on local Control Areas to maintain the integrity of the system.

In general terms we would recommend that NERC operating policies should be issued in the form of specific standards and efforts should be made to eliminate vague or ambiguous language.

Mr. Chairman, to look beyond the recommendations in the NERC Blackout Report, we believe increased reliability can also be achieved through agreements between interested parties. The Midwest ISO is actively exploring additional agreements to ensure greater reliability. It has recently executed a joint operating agreement with its neighboring RTO - PJM - that allows for greater management of the intertwined seams in the Midwest. In the joint operating agreement, we have committed to data exchange and other features that will allow each to be assured of the others performance of tasks to protect the reliability of the regional grid. By having that agreement on file with the FERC, FERC can also serve as a forum for resolution of any future dispute on performance that the parties themselves cannot resolve. Likewise within the Midwest ISO's own region, the terms of the Midwest ISO's tariff are contractually binding on customers and users. These are measures in place today that can be expanded.

Mr. Chairman, you also asked for our views on the reliability provisions contained in the Conference Report on H.R.6 and the identical language found in S.2095 which you recently introduced. The Midwest ISO strongly supports this legislation. We believe that establishing an Electric Reliability Organization reporting to the FERC that develops clear reliability standards and providing that Organization with the authority to impose penalties for violations of the reliability standards would be effective in ensuring a more reliable bulk power system.

Thank you for your time and I would be happy to answer any questions you may have.

B. Corrective Actions to Be Completed by MISO

MISO shall complete the following corrective actions no later than June 30, 2004.

1. **Reliability Tools**. MISO shall fully implement and test its topology processor to provide its operating personnel real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages. MISO shall establish a means of exchanging outage information with its members and neighboring systems such that the MISO state estimation has accurate and timely information to perform as designed. MISO shall fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO shall provide backup capability for all functions critical to reliability.
2. **Visualization Tools**. MISO shall provide its operating personnel tools to quickly visualize system status and failures of key lines, generators or equipment. The visualization shall include a high level voltage profile of the systems at least within the MISO footprint.
3. **Training**. Prior to June 30, 2004 MISO shall meet the operator training criteria stated in NERC Recommendation 6.
4. **Communications**. MISO shall reevaluate and improve its communications protocols and procedures with operational support personnel within MISO, its operating members, and its neighboring control areas and reliability coordinators.
5. **Operating Agreements**. MISO shall reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

FILED
OFFICE OF THE SECRETARY
01 JAN 16 PM 2:07
FEDERAL ENERGY
REGULATORY COMMISSION

In the Matter of	)	
	)	Docket No. RT01-96-000
Alliant Energy Corporate Services, Inc.	)	
(on behalf of IES Utilities, Inc. and Interstate	)	
Power Company),	)	
American Transmission Company LLC,	)	
Central Illinois Light Company,	)	
Cinergy Corp. (on behalf of Cincinnati	)	ORIGINAL
Gas & Electric Company, PSI Energy,	)	
Inc., and Union Light, Heat & Power),	)	
Hoosier Energy Rural Electric Coop., Inc.,	)	
Kentucky Utilities Company,	)	
Louisville Gas & Electric Company,	)	
Northern States Power Company (Minnesota)	)	
Northern States Power Company (Wisconsin), and	)	
Southern Indiana Gas & Electric Company	)	

ORDER NO. 2000
COMPLIANCE FILING OF
SPECIFIED TRANSMISSION OWNERS

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January 16, 2001

010119-0037-1

FERC DOCKETED
JAN 16 2001

MISO Exhibit 1

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January 16, 2001

The Honorable David P. Boergers, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Alliant Energy Corporate Services, Inc., et al., Docket No. RT01-____
Order No. 2000 Compliance Filing

Dear Mr. Boergers:

Pursuant to section 35.34 of the Federal Energy Regulatory Commission's ("Commission") regulations, 18 C.F.R. § 35.34 (2000), and the Notice issued July 20, 2000 in Docket No. RM99-2-000,[1] the Specified Transmission Owners[2] submit this filing to satisfy their compliance filing obligations under Order Nos. 2000 and 2000-A.[3]

1 Regional Transmission Orgs., IV FERC Stats. & Regs., Notices, ¶ 35,040, at 35,307 (2000) ("RTO Filing Guidance").

2 The Specified Transmission Owners are the following transmission-owning signatories to the Agreement of Transmission Facilities Owners To Organize The Midwest Transmission System Operator, Inc. ("Midwest ISO Agreement"): Alliant Energy Corporate Services, Inc. (on behalf of IES Utilities, Inc., and Interstate Power Company), American Transmission Company LLC, Central Illinois Light Company, Cinergy Corp. (on behalf of Cincinnati Gas & Electric Company, PSI Energy, Inc., and Union Light, Heat & Power), Hoosier Energy Rural Electric Cooperative, Inc., Kentucky Utilities Company, Louisville Gas & Electric Company, Northern States Power Company (Minnesota) and Northern
(cont'd)

I. EXECUTIVE SUMMARY

By this filing the Specified Transmission Owners show they have satisfied their current obligations under Order No. 2000 through participation in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO"). Specifically, as required by section 35.34(h)(1), the Specified Transmission Owners state that they currently are participants in the Midwest ISO, that some have been involved in Midwest ISO development since 1996, and that all have devoted very substantial resources to the effort. The Midwest ISO was conditionally approved by the Commission[4] on or before March 6, 2000, as being in conformance with the eleven ISO principles set forth in Order No. 888.[5]

(cont'd)

States Power Company (Wisconsin), and Southern Indiana Gas & Electric Company (collectively, "Midwest ISO Transmission Owners").

3 Regional Transmission Orgs., III FERC Stats. & Regs., Regs. Preambles ¶ 31,089 (1999) ("Order No. 2000"), order on reh'g, III FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000) ("Order No. 2000-A"). References herein to the requirements of Order No. 2000 include those requirements as further explained and clarified in Order No. 2000-A.

4 Midwest Indep. Transmission Sys. Operator, Inc., 84 FERC ¶ 61,231 (1998) ("Midwest ISO Order"), clarified, 85 FERC ¶ 61,250, order on reh'g, 85 FERC ¶ 61,372 (1998).

5 Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Util., Order No. 888, 1991-96 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), order on reh'g, Order No. 888-A, III FERC Stats. & Regs., Regs. Preambles ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000).

As required by section 35.34(h)(2), the Specified Transmission Owners provide in Part III below a detailed explanation addressing the Commission's Regional Transmission Organization ("RTO") requirements specified in Order Nos. 2000 and 2000-A and section 35.34 of the Commission's regulations. This explanation shows that the currently constituted Midwest ISO would:

- Satisfy the independence characteristic for RTOs through a governance structure that is independent of control by any market participant or class of participants and a fair and workable division of section 205 filing authority between the Midwest ISO and the transmission owners.

- Have sufficient scope and regional configuration when compared to other similar transmission entities.

- Possess the operational authority over transmission facilities required for an RTO.

- Have the scheduling, redispatch and maintenance authority to satisfy the short-term reliability responsibilities of an RTO.

- Meet the tariff administration and design function as the sole administrator of an open access transmission tariff that eliminates pancaked transmission charges.

- Implement day one a congestion management mechanism that should be beneficial in relieving congestion through market-based bidding while pursuing a long-term "hybrid" congestion management solution that would combine the desirable features of locational marginal pricing ("LMP") and physical flowgate methodologies.

- Cause internalization of many of the existing loop flows in the Eastern Interconnection and further reduce parallel flow problems by scheduling transactions based on a flow-based analysis.

- Perform the ancillary services function of an RTO while developing real-time balancing market proposals to be in place on or before December 15, 2001.

- Implement and administer an Open Access Same-Time Information System ("OASIS") and independently verify and determine available transmission capability ("ATC") beginning on or before June 1, 2001.

- Implement market monitoring consistent with Order No. 2000.
- Have the authority to satisfy the transmission planning and expansion function of an RTO through its regional planning process and ability to direct construction of upgrades.
- Pursue ongoing interregional coordination efforts and negotiation of seams issues involving key functions with adjacent RTOs.
- Pursue a policy of open architecture that allows independent transmission companies ("ITCs") to emerge within the structure of the Midwest ISO or the transformation of the Midwest ISO to a different structure when appropriate.

In preparing this filing, the Specified Transmission Owners recognize that there are current uncertainties with regard to the Midwest ISO. Pending before the Commission are a number of requests of transmission owners seeking permission from the Commission to withdraw from the Midwest ISO.[6] In some instances those requests to withdraw are conditioned on or tied to the Commission granting other withdrawal requests.[7] In addition, other transmission owners have indicated that they may join the

6 Illinois Power Company, Commonwealth Edison Company, and Ameren have notified the Midwest ISO that they are seeking to withdraw from the Midwest ISO. On December 22, 2000, Illinois Power filed a notice of withdrawal with the Commission which was assigned Docket No. ER01-123. On December 22, 2000, Commonwealth Edison and Exelon Corporation filed a notice of withdrawal which was assigned Docket No. ER01-780.

7 On December 13, 2000, Central Illinois Light Company, Cinergy Corp., Hoosier Energy Rural Electric Coop., Inc., Southern Illinois Power Cooperative, Southern Indiana Gas & Electric Company, and Wabash Valley Power Association notified the Midwest ISO of their conditional withdrawal from the Midwest ISO. On December 20, 2000, they submitted a filing with the Commission seeking permission to withdraw which was assigned Docket No. ER01-731. On January 5, 2001, Louisville Gas and Electric Company and Kentucky Utilities Company filed a notice of withdrawal from the Midwest ISO effective upon the earliest date on which the Commission allows withdrawal by Illinois Power Company, Commonwealth Edison Company, and/or Ameren which was assigned Docket No. ER01-899.

Midwest ISO but have yet to do so.[8] As all of this is as yet unresolved, the Specified Transmission Owners submit this compliance filing, as required by Order No. 2000, based upon the status quo; i.e., based upon the current scope and configuration.

In addition, in Part IV of this submission, the Specified Transmission Owners, pursuant to the Commission's invitation in Order No. 2000,[9] describe a revised rate structure for the Midwest ISO. This rate structure is intended to provide proper incentives to construct and build new facilities and better compensate transmission owners for the risks associated with joining an RTO. The described rate structure will mitigate or eliminate disincentives to construct transmission facilities by providing for the direct assignment of transmission facilities on a basis that treats all loads and customers comparably, by the establishment of a deferral mechanism, and through shorter depreciation periods and higher returns. The Specified Transmission Owners also request that if the Commission finds that a transitional revenues lost approach for base rate transmission pricing is acceptable in the Alliance RTO proceeding,[10] that it be extended to the Specified Transmission Owners. The Specified Transmission Owners, like the Alliance owners, face the loss of substantial revenues that they receive today as a result of joining an RTO. Such action would promote consistent pricing within the Midwest, which should facilitate reduction of seams issues.

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8 In their Order No. 2000 filings made in October 2000, UtiliCorp United (Docket No. RT01-45) and Otter Tail Power Co. (Docket No. RT01-63) indicated that they would join the Midwest ISO.

9 See 18 C.F.R. § 35.34(e).

10 The Alliance proposal is currently pending before the Commission in Alliance Cos., Docket Nos. ER99-3144, et al.

BEFORE THE
ALBERTA ENERGY AND UTILITIES
BOARD

IN THE MATTER OF:
ESBI Alberta LTD.
EAL 2002 Application No.: 1248859
TRANSMISSION CONGESTION
MANAGEMENT PRINCIPLES
File No.: 1804-4

A Critique of the Proposals of ESBI Alberta Ltd. Regarding Congestion Management Principles

March 4, 2002

SUBMITTED ON BEHALF OF
CANADIAN NATURAL RESOURCES LTD.

Prefiled Direct
Evidence of Canadian
Natural Resources,
Prepared by
Dr. Mathew J. Morey
Principal
Envision Consulting

MISO Exhibit 2 - Morey witness

- instantaneous delivery (at nearly the speed of light), thus the system operator must be in control of the imbalances, the congestion and the interdependencies all at once, which requires scheduling in advance, monitoring and dispatch in real time.

In light of these characteristics, the market design and the trading arrangements must answer several questions:[57]

- regarding the system operator's purchase and sale of energy to address imbalances—from whom, to whom and at what price?
- regarding the system operator's management of congestion—who gets dispatched up or down and what does it take to get them to comply with orders?
- regarding the system operator's purchase of ancillary services—how are they procured, what price is paid for them and how are the costs recovered from customers and which customers pay?
- regarding scheduling and dispatch, how does the system operator decide who gets dispatched, how are forward contracts tied to scheduling, and how should settlements be tied to physical operations?

Four Pillars of Market Design

The set of trading arrangements dealing directly with the four characteristics of electricity and answering the questions constitute the "four pillars" of good electricity market design. Other aspects of market design become straightforward once these pillars are in place. Thus, the four pillars of market design are trading arrangements that address:

- Imbalances;[58]
- Congestion management;
- Ancillary services; and
- Scheduling and dispatch.

For the market design to work well, all these four pieces must be made to work together. The main operational and commercial arrangements that are important, especially important to this proceeding, are those that relate to *imbalances* and *congestion management*. But how these two are addressed carries over into the trading arrangements for ancillary services, scheduling and dispatch. Finally, how congestion and imbalances are managed affects the commercial arrangements, as defined by the tariff, between the Transmission Administrator and transmission customers. The tariff defines the rights of transmission users

[57] The detailed answers to these questions are beyond the scope of this paper. We pose the questions to stimulate thinking about these issues.

[58] Imbalances are deviations in real-time from the scheduled loads and generator outputs that must be managed by the System Controller through incremental and decremental adjustments to output, and in some cases to dispatchable load resources.

A Model Market Design

Thus, the principal features of a market design and trading arrangements that establish the four pillars and comprehensively address the questions are as follows:[59]

- A system operator-run spot market, which also serves as the imbalance market. A system operator-run spot (real-time) market is the most efficient mechanism for dealing with the complex operational problems of delivery, since the system operator has to run an imbalance system no matter what the trading model. The incentive-compatible price for imbalances is the market-clearing price. Energy traded in the spot market is the same product, time and place as imbalance energy – the prices will converge. There is no reason to try to keep them separate.
- Supply offers and demand bids consisting of "reservation" prices, with the spot market clearing price set at the highest generator offer or the lowest demand bid that clears the market. The market-clearing price can be found through optimization, calculated by security-constrained dispatch software.
- Day-ahead markets in addition to spot markets.
- Locational prices for energy. These provide the right economic signals for location of new generation and load, for expansion of transmission, and for congestion management.
- Operating reserves, including regulation reserves, integrated with energy markets and priced as options. Reserves are options to call for supply of energy. When the system operator exercises these options in real time, generators provide energy, so the settlement price for the energy should be the spot market clearing price. It is inefficient to try to separate the pricing of energy and energy obtained in reserve markets – it increases prices and contributes to shortages.
- Congestion management integrated with the system operator optimization process and locational energy prices, with congestion prices paid by scheduled contracts based on locational price differences. This is the only workable way to deal with real-time congestion on a large and complex network with many traders. It is efficient and incentive-compatible. It has the additional virtue of giving a good picture of where transmission expansion is needed.
- The treatment of transmission losses integrated with the security-constrained optimization and with the determination of locational spot prices.
- Contracts scheduled with the system operator; net quantities (spot price transactions) settled financially. This system of scheduling and settling contracts is simple and efficient.
- Trading arrangements that enable investment in and ownership of the transmission wires by independent merchant developers.[60] Greater participation of

[59] We will not discuss all these features, but include them all for completeness of the picture of a well-rounded market design and trading arrangements.

merchant developers, perhaps encouraged by development incentives, may help to get much-needed upgrades in the ground sooner.

- Long-term tradable financial transmission rights, auctioned by the system operator. These permit traders to hedge against congestion charges. They also have several additional useful properties – they can be used to compensate those who pay for new construction of transmission; and they can be used to provide incentives to the transmission owners to maintain the transmission system properly.[61]

- Hourly (or more frequent) settlement intervals, together with the required hourly metering for final customers, so as to enable meaningful demand response.[62] Retail prices that reflect the spot price for marginal purchases so that price responsive demand is introduced to help complete the market.[63]

- Capacity obligations can be useful in the interim *only* when hourly metering, hourly pricing and demand response are inadequate. The other interim alternative is a rational price cap based on value to consumers of lost load. One of these should be in place in the interim, if demand bidding cannot be implemented expeditiously.

This model for market design is known to work. Most competitive markets throughout the world have adopted some form of it, although no marketplace yet has all the features. The fact that some marketplaces, such as the regional markets of the Northeastern U.S. and California and Texas, did not include all these features initially, but have since added some of them, suggests strongly that development can proceed in stages, so long as the

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[60] In general, any time the expected costs of paying for congestion exceed the costs of an enhancement, the enhancement would be economically justified. When projected annualized congestion costs exceed investment costs, including a competitive return on that investment, the enhancement should become potentially attractive to independent (merchant) transmission developers and to investment coalition partners. Investment coalitions could be formed from sets of generators, distribution utilities, industrial customers and independent investors. Such coalitions may be able to build transmission enhancements to resolve short-run and long-run congestion problems more quickly than the Transmission Administrator. In any case, merchant development or coalitions of investors in transmission expansion should be allowed to flourish as a possible efficient alternative to expansion through the TA alone. The key to encouraging such private initiatives is to ensure that the property rights accrue to developers and that the value of those rights is market based.

[61] These are not the only means of motivating transmission owners; performance-based regulation also provides an incentive approach that may be superior to traditional rate-of-return regulation.

[62] While all final customers should be metered to separate classes and types, demand response from half the load would be sufficient to control wholesale prices. In many places, large industrial customers *are* about half the load.

[63] Retail tariffs can be designed to give consumers something they want—stable, predictable monthly bills—and provide the market with something it desperately needs—price responsive demand. Tariffs can be designed so that a consumer would pay an average retail rate for a contracted reference number of kWh, which would provide stable monthly bills. For consumption above the reference kWh level, the consumer would pay a price indexed to the spot market clearing price. Thus, exposing consumers to spot prices for consumption at the margin, which is likely to occur at peak periods, will likely reduce demand at these critical times, reducing the demand for peaking plants and for new transmission.

right features are attended to first.[64] The design works smoothly, incorporating the necessary complexities of the transmission system, and providing incentive-compatible rules. A major benefit is that *independent generators can find an outlet for their power without having to find specific customers*, and can purchase any extra energy they need automatically. This provides liquidity to underpin real competition in the production markets. The major downside is, paradoxically, the transparent price, which is a magnet for "price caps," with predictably bad results.[65]

5.2 Alberta's Market Design and Trading Arrangements

Table 2 summarizes the features of the Alberta electricity market design in terms of the key elements outlined above.[66] From this summary we can observe that the architecture of Alberta's power and transmission markets possesses some features of a good design and is missing some critical elements.

On the plus side, the System Controller of the Power Pool of Alberta dispatches grid resources in real-time (i.e., on a minute-to-minute basis) to set a uniform (i.e., system-wide) market-clearing price based on the marginal demand bid and supply offer prices received in the day-ahead energy market that it administers.[67] The TA administers a day-ahead market for ancillary services and a day-ahead market has been developed through a separate exchange (i.e., Alberta Watt Exchange Limited) that sets out day-ahead financial energy contracts and determines market-clearing prices for ancillary services (regulation, spinning, non-spinning and supplemental reserves) that also can be purchased by the TA.[68]

Unfortunately, the most important components of a good market design from the standpoint of congestion management are missing: *locational energy spot pricing* and *tradable transmission rights.* Without locational spot pricing, congestion prices to recover constraint costs cannot be based easily on differences in locational marginal prices. Without tradable transmission rights in the context of market-determined prices, allocation of transmission capacity must take place according to a priority system based on the type of service purchased, on a first-come first-served system and when the system is constrained must be allocated according to those priorities, with only a vague notion of

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[64] California is an example of how important it is to get particular features right, such as congestion pricing, ancillary services markets integrated with the spot market and transmission rights. The most recent proposal of the California ISO is to adopt almost all of the features of this model design.

[65] Nevertheless, price caps may be necessary in the interim if demand response is severely limited or absent.

[66] The features of Alberta's market design can be gleaned from documents such as Tabors (2001a, 2001b), and the TA's application to the EUB, and the TA's Rate Schedules.

[67] The Power Pool of Alberta is a not-for-profit corporation established under the Electric Utilities Act of 1995.

[68] The problems that arose in California with the separation of the ISO's spot market from the day-ahead Power Exchange, offer some useful lessons about the difficulties of efficiently coordinating separate institutions and ensuring that market rules in the day-ahead market are compatible with those in the real-time market, especially as between energy and ancillary services and congestion management.

problem. However, during the period January to December 1998, only 11 unique flowgates accounted for 80 percent of the congestion. The congestion charges associated with these eleven flowgates accounted for only 4.74 percent of the total congestion costs in this period. Therefore, using significant congestion of flowgates to define commercially significant flowgates may be inadequate. If these 11 flowgates were designated significant by virtue of the congestion they experience, over 95 percent of the congestion costs would have to be allocated to and recovered through an uplift charge.

When historical congestion charges for the period January to April 1999 were used to define the commercially significant flowgates, 17 flowgates managed to account for 56.5 percent of the costs for the same period in 2000. Ott's analysis illustrates a simple point: significant congestion or congestion charges cannot be used as an accurate predictor future congestion costs because of the weak correlation between the amount of congestion experienced on unique flowgates and the associated costs of congestion relief.

While the congestion on these flowgates physically accounts for a significant proportion of the congestion in the PJM system, that portion of the analysis does not answer the question of what flowgates would be considered commercially significant. One might conclude that the designation of some number of flowgates between 26 and 44 might capture between 80 and 90 percent of the congestion costs.

Financial Rights Are Superior to Physical (Flowgate) Rights

The complex interactions inherent in electric networks present special problems for the operation of competitive wholesale markets. When market participants have choices, simplified models of the real system can create externalities and perverse incentives that could be and have been relentlessly exploited by entities seeking the very profits that are at the core of the theory of the competitive model. Consequently, getting the spot market prices and prices for transmission use right is far more important than making life simple.

The flowgate model is based on a number of simplifying assumptions, and the simplifying assumptions are not literally true. The argument is that the costs of deviations from a small set of commercially significant flowgates will be small and the benefits of concentrating on a small set are large. If the argument were true, there would be a commercial opportunity to create flowgate trading without upsetting efficient pricing in the more complex real-time market managed by the system operator. The apparent contradiction of the flowgate proposal for a centralized trading model, like the centralized model used in Alberta, is that it will require the Power Pool and the TA to become deeply involved in the business of a supposedly simple and low risk forward trading market. This raises serious questions about the creation of another set of subsidies and perverse incentives to handle the deviations when they do become significant.

PUBLIC VERSION

CONGESTION MANAGEMENT SYSTEM (CMS) IMPLEMENTATION STUDIES RELATED TO CONGESTION

prepared for

ISO New England

by

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January 14, 2003

MISO Exhibit 3 Morey witness

We present our major findings and conclusions in the next section. Many more findings, conclusions and recommendations are presented with supporting details in Parts 2 through 4 of this report.

3. KEY CONCLUSIONS AND RECOMMENDATIONS[3]

3.1. The Benefits of LMP

Both NYISO and PJM have demonstrated the viability of LMP as a congestion management tool. A similar adoption of LMP by ISO-NE could likely result in substantial benefits for New England electricity markets. In the short run, LMP produces prices that induce the least-cost dispatch of generation services while providing a market-based tool to achieve efficient congestion management. In the long run, LMP induces the location of new generation investment where it is most valuable in holding down costs and maintaining power system reliability. LMP also provides market-based signals to assist transmission planners in determining the efficient amount, location, and timing of transmission expansion.

LMP will help ISO-NE manage transmission congestion. The historical practice of uniform pricing contributes to congestion problems within the New England system. Uniform pricing implicitly assumes an absence of transmission congestion in the power system even when such congestion is known to occur. When the reality of transmission congestion is ignored, the users of congested facilities face the same price for transmission service as do the users of uncongested facilities. Consequently, the uniform pricing method encourages generation investment and operation without regard to load locations, resulting in inefficient investment decisions and higher costs to LSEs. By its very construction, LMP introduces efficient congestion pricing.

For the scenarios in our study, we find that the introduction of LMP tends to reduce 2003 power system prices on average and particularly during the peak periods. However, we do not generalize this finding to predict lower short-term prices when compared to the prices from a uniform pricing method. Our findings on the LMP price impacts are limited to the specific scenarios modeled in this study. Furthermore, we find that the distribution among market participants of the net benefits from LMP is sensitive to changes in supply and demand conditions. Under some conditions, small changes in supply or demand can lead to large changes in prices that, in turn, can lead to large changes in the distribution of benefits and costs among different market participants.

The locations that are most likely to see higher wholesale prices under LMP are the regions that rely upon power imports to serve load and where imports are constrained by limited transmission system capability. Such import-constrained regions are known as "load pockets." In this study, we focus on five major New England load pockets: Norwalk/Stamford, Southwest Connecticut, Connecticut, Vermont, and Northeast Massachusetts/Boston (NEMA/Boston). Absent some transitional mechanisms, such as assigned transmission rights, the load-serving entities (LSEs) that serve these load pockets, particularly Norwalk/Stamford and Vermont, will likely see increased electricity costs *relative* to LSEs that serve loads elsewhere in the system. Because it

[3] We conducted this study prior to the issuance of the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Standard Market Design (Docket No. RM01-12-000), July 31, 2002. This Proposed Rulemaking and an overwhelming majority of the views expressed in this report are consistent, but the Final Rule may lead us to revise a few of our views (such as our skepticism about transmission right options).

really is more costly to deliver power to these load pockets than to other locations, LMP may be construed as merely revealing the wholesale cost differentials among locations. It may nonetheless be desirable to use mechanisms, such as the assignment of transmission rights to LSEs that serve load pockets, to soften any short-run adverse impacts of LMP upon the customers in these load pockets.[4]

Our analysis indicates that, for the system as a whole and for all load pockets except NEMA/Boston, LMP tends to mitigate the adverse effects on LSEs of non-competitive bidding. We believe that this occurs because LMP limits the geographic extent of the adverse consequences of non-competitive bidding, while uniform pricing may spread these adverse effects over an entire whole power system. We expect that this benefit of LMP applies generally to cases we do not examine in this study.

We also find that LMP creates locational price variations. Transmission constraints and losses drive the extent of locational price variation. Because our Part 3 analysis gives only limited consideration to the causes of transmission constraints and to transmission contingencies, we believe the actual locational price variations will likely be larger than those indicated by our Part 3 results. Such locational price variation naturally occurs in a deregulated power market, and it has the benefit of inducing generation investment of efficient types (e.g., baseload vs. peaking) and at efficient locations.

3.2. Competition and Market Monitoring

Although competition may be sufficient to ensure that electricity prices are at competitive levels at most times in most of the New England system, competition in load pockets seems problematic. In particular, generation ownership in the Southwest Connecticut and Connecticut load pockets is concentrated, while ownership in the Norwalk-Stamford and NEMA/Boston load pockets is highly concentrated.[5]

To identify instances in which market participants may exercise market power, ISO-NE developed a market monitoring program that compares favorably with those of the other Northeastern ISOs. To limit the adverse impacts of non-competitive behavior in load pockets, ISO-NE uses two main mitigation measures: generator-specific bid caps that are dependent upon resource reference prices, and price caps applicable to the whole market. We believe that ISO-NE's existing measures generally limit the exercise of market power.

3.3. Key Recommendations

Our study makes recommendations for pricing and market monitoring actions in the longer term. We briefly summarize our key recommendations in this section. These and other recommendations are discussed at greater length in Parts 2 through 4 of this report.

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[4] This type of assignment appears to be a feature of the "congestion revenue rights" proposed by the Federal Energy Regulatory Commission, *op cit.*

[5] A "concentrated market" is one in which the Herfindahl-Hirschman Index (HHI) exceeds 1,800, while a "highly concentrated" market is one in which the HHI exceeds 2,500. Note that although ownership concentration may serve as an indicator of market competitiveness in some circumstances, it can overstate competitiveness in electricity markets because of the non-storability of the commodity and the unresponsiveness of demand to supply conditions.

February 11, 2004

Mr. Jim Torgerson
President and CEO
Midwest ISO
701 City Center Drive
Carmel, IN 46032

Dear Jim:

It is our understanding that MISO has spent a considerable amount of time and resources to analyze a suggestion by certain MISO stakeholders that MISO delay the implementation of the Day 2 market for the western MISO footprint. We are strongly opposed to any attempt by MISO to bifurcate the implementation of Day 2.

There already exists a tremendous momentum at MISO to design a Day 2 tariff for the entire MISO footprint, and all issues, up until now, have been addressed assuming a single market for the entire MISO footprint. All MISO and market participant preparations have proceeded under the assumption that a Day 2 market, and the associated energy pricing and transmission rights structure, would encompass all of the MISO member regions, including training, infrastructure (hardware and software), modeling, market design, private sector investment plans and other related activities.

A split market, or a staged implementation, would create an internal seam that bifurcates MISO. Not only would such an intra-MISO seam involve additional MISO administrative costs and market participant costs, it would require yet another shift in effort by all involved to examine the fundamental elements of the revised market structure. The MISO, as the RTO, has only a single OATT tariff. Numerous technical issues and structural changes would have to be addressed diverting stakeholders' resources from addressing the Day 2 tariff issues as well as the issues involved in the common market formation. The MISO and its stakeholders are deliberating on the exact process by which many facets of today's operations will change when MISO operates under its proposed Day 2 tariff. We have concerns that the proposed phase-in implementation will make MISO efforts to craft a compromise process even more difficult. Moreover, we are concerned that inequities will result due to the creation of two customer classes (i.e., physical and financial), and that reliability may suffer.

1135) 541-4184 - [illegible]

Mr. Jim Torgerson
Page 2
February 11, 2004

FERC's approval of the MISO RTO was based in part on its regional "scope and configuration" adequacy. Moving forward with a reduced-scope RTO represents a step backwards in this regard.

Moreover, while we do not support the idea of bifurcating the implementation of Day 2, if MISO were to consider that possibility, we believe that every MISO member should be given the opportunity to decide whether to participate in the first implementation phase or the second implementation phase.

Very truly yours,

/s/Ronald R. Jackups
Vice President – Electric System Operations
Cinergy Corp.

/s/William E. Garrity
Vice President Electric and Gas Supply
Consumers Energy Company

/s/Michael E. Champley
Sr. Vice President – Regulatory Affairs
DTE Energy

/s/Stanley F. Szwed
Vice President, Energy Delivery Policy
FirstEnergy Service Company

/s/Dave Sandefur
Vice President, Power Supply
Hoosier Energy

/s/Gayle Mayo
Executive Vice President and COO
Indiana Municipal Power Agency

/s/Mark Johnson
Director of Transmission
Louisville Gas & Electric Company/
Kentucky Utilities Company

/s/Frank A. Venhuizen, P.E.
Director, Electric Transmission and Market Services
NIPSCO

/s/Bill Hutchison
Systems Department Manager
Southern Illinois Power Cooperative

/s/Ronald G. Jochum
Vice President Power Supply
Vectren

/s/Lee Wilmes
Vice President of Power Supply
Wabash Valley Power Association

Table RRM_1-1 Corrected

Summary of the Near-Term Benefits and Costs of MISO Membership and Stand Alone Operation of the LGE / KU Transmission System

	2004	2005	2006	2007	2008	2009	2010
Cost of MISO Membership							
System Operations & Transmission Costs							
MRMD Staffing, Training, Consulting		$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
Miscellaneous Uplift Charges		$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Congestion Costs Not Covered by FTRs		$73	$73	$73	$73	$73	$73
Implementation and Administration Costs							
Total of Schedules 10, 16, 17 Charges		$13,023,172	$13,434,813	$13,725,538	$13,977,637	$13,526,898	$12,441,769 (1)
Ancillary Market Cost				$280,000	$280,000	$280,000	$280,000
Legal, Regulatory, & Transaction Costs							
Net Cost of Committee Participation, Contracts		$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
Net FERC Attachment O Fees		$860,000	$860,000	$860,000	$860,000	$860,000	$860,000
Less: Transmission Revenues							
Less: MISO Schedule 1, 7, 8, and 14 Revenues		($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)
Total Cost of MISO Membership		**-$6,641,508**	**-$6,229,867**	**-$5,659,142**	**-$5,407,043**	**-$5,857,782**	**-$6,942,911**
Cost of Stand Alone Operation							
MISO Exit Fee	$38,200,000						
System Operation Costs							
Additional Staffing		$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
Systems Related Costs		$720,000	$720,000	$720,000	$720,000	$720,000	$720,000
Congestion Management Costs		$3,657,767	$3,657,767	$3,657,767	$3,657,767	$3,657,767	$3,657,767
Lost Revenues							
Lost FTR Revenue		$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Lost Margin on Wholesale Sales		$8,348,007	$8,348,007	$8,348,007	$8,348,007	$8,348,007	$8,348,007
Less: Transmission Revenues							
Less: LGE / KU Sch. 1, 7, & 8 Transmission Revenue on Off-system Sales		($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)
Total Cost of Stand Alone Operations	**$38,200,000**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**
Net Cost Savings of MISO Membership	**$38,200,000**	**$12,518,750**	**$12,107,109**	**$11,536,384**	**$11,284,285**	**$11,735,024**	**$12,820,153**
Cumulative Net Savings of MISO Membership	**$38,200,000**	**$50,718,750**	**$62,825,859**	**$74,362,243**	**$85,646,528**	**$97,381,552**	**$110,201,705**
Net Present Value Savings from MISO Membership in 2004	**$38,200,000**	**$11,699,766**	**$10,574,818**	**$9,417,126**	**$8,608,727**	**$8,366,910**	**$8,542,609**
Cumulative NPV Savings from MISO Membership	**$38,200,000**	**$49,899,766**	**$60,474,584**	**$69,891,710**	**$78,500,437**	**$86,867,347**	**$95,409,956**

Note:
1. Corrected.

MISO Exhibit 5 - McNamara

Corrections and Additions to
The Direct Testimony of Dr. Ron R. McNamara
And Exhibit RRM-1

Q. Do you have any corrections to your pre-filed Direct Testimony?

A. Yes. The following typographical errors in my Direct Testimony should be corrected:

- Page 5, on Line 6, please substitute the name "LG&E/KU", replacing the name "LG&E" ; and
- Page 16, on both Lines 6 and 8, please substitute the name "Broadford", replacing the name "Bradford".

And, the following typographical error should be corrected in Exhibit RRM-1:

- Page 8, in the second full paragraph, please substitute the figure "2915", replacing the figure "2195".
- In Table RRM_1-1, the figures for Cost of MISO membership in the row labeled "Total of Schedules 10, 16, 17 Charges" should be corrected to match the figures in Mr. Holstein's testimony. These changes are reflected in "Table RRM_1-1 Corrected."
- In Table RRM_1-5, in the section of the table titled "Scaling Stand Alone Net Margin on Off-System Sales to 2002 Actual Net Non-Requirements Sales for Resale, in the Comment related to Line Number (3), please substitute "Line 2 / Line 1", replacing the comment "Line 2 / Line 3".

Q. Does this conclude the additions and corrections to your testimony?

A. Yes, it does.

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

REVISED DIRECT TESTIMONY OF

MICHAEL P. HOLSTEIN

VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Filed: December 29, 2003
As Revised: February 27, 2004

MISO Exhibit 6 - Holstein

III. FUTURE BENEFITS

Q. What benefits will LG&E/KU retail customers realize for 2005 through 2010 as a result of the companies' continued participation in the Midwest ISO?

A. The benefits that LG&E and KU's retail customers will realize in the future as a result of LG&E and KU's continued participation in the Midwest ISO include (1) benefits that will be realized as a result of the surcredits associated with the companies' merger; (2) ongoing benefits as a result of improved reliability; and (3) avoided labor and information system costs. Additionally, in the future, LG&E and KU's retail customers will enjoy substantial benefits as a result of the Midwest ISO's implementation of short-term energy markets in its region. Finally, if LG&E and KU remain in the Midwest ISO, LG&E and KU's retail customers will avoid paying the withdrawal fee that would be imposed under the Transmission Owners' Agreement if LG&E and KU withdraw from the Midwest ISO.

Q. What benefits will LG&E/KU retail customers receive during that period as a result of the companies' merger?

A. As described above, under the settlement agreement approved by the Commission on October 16, 2003, LG&E and KU's retail customers will receive an additional **$125,804,658**~~$161,748,846~~ in billing credits as a direct result of the non-fuel savings created by the merger. That amount of billing credits will be paid through June 2008. The costs to achieve the merger savings have been fully amortized, so those billing credits and the lump sum payments made to certain customers will reflect the entire amount of additional merger non-fuel savings realized through June 2008, without offset.

Additionally, LG&E and KU's retail customers may receive additional benefits for non-fuel merger savings realized after June 2008.

Q. What are the future benefits of improved reliability through 2010?

A. Based on Mr. Falk's mean value of the reduced probability of loss of load of $2.7 million annually, the reliability benefits through 2010 to LG&E and KU's retail customers as a result of the companies' continued participation in the Midwest ISO is **$16.2**~~$18.9~~ million.

Q. What is the sum total of the estimated merger non-fuel savings and reliability benefits through 2010?

A. The sum total of those amounts is approximately **$142.0**~~$181~~ million.

Q. What benefits will LG&E/KU retail customers realize as a result of the Midwest ISO's implementation of short-term energy markets in its region?

A. Dr. McNamara addresses benefits that LG&E and KU's retail customers will realize as a result of the Midwest ISO's short-term energy markets. Dr. McNamara's testimony quantifies certain economic benefits that can only be realized by LG&E and KU's retail customers if LG&E and KU continue to participate in the Midwest ISO. Dr. McNamara estimates that those benefits range between $11.3 million and **$12.8**~~$12.9~~ million annually. The net present value of the benefits quantified in Dr. McNamara's testimony is $95 million over the period 2005 through 2010. As Dr. McNamara points out, however, if LG&E and KU continue participating in the Midwest ISO, LG&E and KU's retail customers will realize other potentially significant benefits that cannot easily be quantified.

Q. Do the net benefits quantified in Dr. McNamara's testimony include the estimated merger benefits and reliability benefits quantified above as $142.0~~$181~~ million over the same period?

A. No, they do not.

Q. Do the net benefits quantified in Dr. McNamara's testimony include a projection of the withdrawal fee required under the Transmission Owners Agreement?

A. Yes.

Q. How much is the projected withdrawal fee?

A. If LG&E and KU decide to pursue a withdrawal, the amount of the withdrawal fee will depend on the effective date of the withdrawal. Under Article Five of the Transmission Owners Agreement, a withdrawing transmission owning member is responsible for all financial obligations incurred and payments applicable to time periods prior to the effective date of the withdrawal. Furthermore, under the Transmission Owners Agreement, a transmission owning member's withdrawal is not effective until December 31 of the calendar year following the calendar year in which notice of withdrawal is given. If LG&E and KU were to give the Midwest ISO a proper notice of withdrawal in calendar year 2003, the earliest they could withdraw is December 31, 2004, assuming all regulatory approvals were obtained in that time frame. Based on the Midwest ISO's current and projected obligations as of December 31, 2004, LG&E and KU's estimated withdrawal obligation as of December 31, 2004, would be $38.2 million.

Q. Why is it not the case, as LG&E and KU contend, that they could withdraw from the Midwest ISO within 30 days of an order by this Commission directing them to do so?

A. The provision in Article Seven of the Transmission Owners' Agreement that LG&E and KU refer to was intended to apply only during the preoperational period — that is from the time those companies executed the Transmission Owners' Agreement until the Midwest ISO commenced operations. This was the position of the original applicants, including LG&E and KU, before the FERC. The language of Article Seven was drafted to cover the securing of state regulatory authority to participate. It begins, "In the event any state regulatory authority refuses to permit participation by a signatory or imposes conditions on such participation which adversely affect a signatory...." Transmission Owners Agreement at Sheet No. 80. The context for the operation of the provision was in the preoperational stage of the Midwest ISO. The potential for an open-ended availability of the 30-day notice and lack of required FERC approval was challenged by certain intervenors in the original FERC docket seeking acceptance of the Transmission Owners' Agreement. *See Midwest Independent Transmission System Operator, Inc.*, 84 FERC ¶ 61,231 at 62,150-151 (1998). In its order approving that agreement, the FERC summarized the Applicants' (including LG&E and KU) response as follows: "Applicants state that only two types of withdrawals are allowed without Commission approval: regulatory out withdrawals and withdrawals by December 31, 1998, each of which, according to Applicants, should be exercised well before Midwest ISO operations begin." *Id.* Based on that interpretation, the FERC concluded:

> We will permit withdrawals from the Midwest ISO Agreement for the reasons stated in Articles V and VII A of the Agreement. However, the Agreement must be revised to clarify that any notice of withdrawal from the Agreement must be filed with the Commission and may become effective only upon the Commission's approval. We also note that any withdrawal from the ISO Agreement by a public utility Transmission Owner after the ISO begins operations will require a

> Section 203 filing to transfer control over the jurisdictional facilities under the control of the Midwest ISO back to the Transmssion Owner.

Id. at 62,151.

Q. How do the benefits you have described above compare to LG&E and KU's costs of Midwest ISO membership for 2005 through 2010?

A. LG&E and KU will continue to pay the Schedule 10 charges described above. Additionally, when the Midwest ISO implements the energy markets, including the administration of Financial Transmission Rights, it will recover its costs for providing those services through two new rate schedules in the Midwest ISO OATT: Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder) and Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder). As explained by Dr. McNamara, LG&E and KU's retail customers may also incur certain other costs as a result of participating in the Midwest ISO. The table below illustrates the magnitude of the benefits I have described above relative to the projected costs LG&E and KU will incur to participate in the Midwest ISO through 2010.

Benefits to LG&E and KU Retail Customers **for 2005** Through 2010:

Costs Through 2010	
Schedule 10 Costs	~~$50,000,000~~ **$43,900,000**
Schedule 16 Costs	~~$9,000,000~~ **$8,600,000**
Schedule 17 Costs	~~$29,000,000~~ **$27,600,000**
Total Costs	~~$88,000,000~~ **$80,100,000**
Benefits Through 2010	
Net Energy Market Benefits	~~$197,800,000~~ **$190,400,000**
Merger Surcredits	~~$161,700,000~~ **$125,800,000**
Reliability Benefits *f*(loss of load)	~~$18,900,000~~ **$16,200,000**
Total Benefits (nominal $)	~~$378,400,000~~ **$332,400,000**
Net Benefits (nominal $)	~~$290,400,000~~ **$252,300,000**

The table above includes 100 percent of the projected costs to be charged to MWhs of Transmission Service associated with LG&E and KU load in 2004 through 2010 under Midwest ISO OATT Schedules 10, 16 and 17. As I explained above, Midwest ISO's Schedule 10 costs are not currently included in base retail rates. However, LG&E and KU recently announced that they will seek an increase in their retail rates. LG&E and KU's notices to the Commission of the forthcoming rate filings indicated that their application and testimony in support of the rate increases would be filed on December 29, 2003, the same day this testimony is due to be filed in this proceeding. Accordingly, I do not know whether LG&E and KU will seek to include their Schedule 10 costs in their historic test year or will propose some other mechanism by which retail customers would pay a portion of the Midwest ISO's Schedule 10, 16 and 17 costs. The table above is a representation of the effect of fully recovering these costs from retail customers.

Q. Do you believe the Commission should allow LG&E and KU to recover a portion of their Schedule 10, 16 and 17 costs from their retail customers?

A. Yes. In fact, I believe it is appropriate for LG&E and KU to include in retail rates all of the costs of the Midwest ISO under Schedules 10, 16 and 17. As noted earlier in my testimony, participation in an RTO was a necessary condition to obtain FERC approval for the merger. As such, the cost of RTO participation should properly be considered a cost to achieve the merger, a merger that has produced substantial and quantifiable benefits for retail ratepayers. Further, given the federal requirement to join an RTO as a means of mitigating market power, it is my opinion that one hundred percent (100%) of the Midwest ISO costs should be included in retail rates as opposed to shared 50/50 or on some other basis between shareholders and ratepayers. Finally, I believe it is appropriate for all Schedule 10 costs to date to be capitalized and recovered through retail rates for the same reasons I believe prospective costs should be included in retail rates.

IV. MIDWEST ISO'S MANAGEMENT OF COSTS

Q. Have you reviewed Mr. Thompson's testimony filed on September 22, 2003, in this proceeding?

A. Yes, I have.

Q. On page 15 of his testimony, Mr. Thompson asserts, "Currently, there are no effective checks on the expenditures of MISO management: because MISO is a non-profit organization with no equity at risk, there is currently no practical means to