Exhibit No. __ (MISO-4)

PREPARED DIRECT TESTIMONY OF
RONALD R. MCNAMARA

ON BEHALF OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
DOCKET NO. ER04-____-000 BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	))	Docket No. ER04-____-000

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RONALD R. MCNAMARA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am employed as Vice President of Regulatory Affairs and Chief Economist for the Midwest Independent Transmission System Operator, Inc. (the "Midwest ISO").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

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

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

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

Q. WHAT IS THE PURPOSE OF YOUR PREPARD DIRECT TESTIMONY?

A. My testimony has four primary objectives. First, I will provide an explanation of why the Midwest ISO is proposing to implement an energy market. Second, I will explain the essential elements of an effective energy market. Third, I will address ten (10) of the substantive market design elements that have been developed largely through discussions with stakeholders. Fourth, I will discuss the compatibility of the Midwest ISO's proposed energy market design with the existing energy markets administered by PJM Interconnection, L.L.C. ("PJM").

Q. WHAT OTHER DIRECT TESTIMONY IS THE MIDWEST ISO SUBMITTING IN SUPPORT OF THE SUBJECT FILING?

The Midwest ISO is submitting Direct Testimony on the following issues to provide additional information and support for the subject filing: (1) **Professor William W. Hogan**, Lucius N. Littauer Professor of Public Policy and Administration at the John F. Kennedy School of Government, will discuss equitable treatment of grandfathered agreements, solutions for preservation of grandfathered agreements rights, the continuing role of the Organization of Midwest ISO States, Inc. ("OMS") in treatment of grandfathered agreements, and public interest requirements for reformation of inconsistent grandfathered agreements; (2) **Paul Gribik**, Midwest ISO Director, FTR Markets, will discuss the role of Financial Transmission Rights ("FTR") in the energy markets, the initial process for distributing FTRs among Market Participants, the involvement of the OMS in the design of the FTR allocation methodology, and the preparation of Illustrative FTRs; (3) **Joe Gardner**, Midwest ISO Director, Real Time Operations, will discuss the separation of appropriate functions between Control Area operations and the Midwest ISO, development of the Reliability Charter, resolution of outage issues, and the importance of day-ahead load forecasting procedures; (4) **Richard Doying**, Midwest ISO Director, Market Development and Analysis, will describe the stakeholder process used by the Midwest ISO to develop the energy markets, and the process by which key issues that have been raised since the Midwest ISO's original energy markets filing on July 25, 2003, were addressed; (5) **Mark Volpe**, Midwest ISO Director of Regulatory Affairs, will discuss the modular format of the Tariff, the development of Modules C, D and E, changes to preceding tariff provisions, and resolution of miscellaneous Tariff clarification issues; (6) **Michael Holstein**, Midwest ISO Vice President and Chief Financial Officer, will discuss enhancements to the Midwest ISO's creditworthiness procedures to support the energy markets; and (7) **Dr. David Patton**, President of Potomac Economics and the Midwest ISO's Independent Market Monitor, will discuss the development of the Midwest ISO's Independent Market Monitor ("IMM") and Market Mitigation procedures and describe improvements to previously filed Attachments S and S-2 to the Midwest ISO OATT. (5) (7

II. THE MIDWEST ISO AND ITS OPEN ACCESS TRANSMISSION TARIFF WILL SUPPORT AND ENHANCE REGIONAL RELIABILITY.

Q. HOW DOES THE MIDWEST ISO HELP ENSURE REGIONAL RELIABILITY TODAY?

A. When the Midwest ISO began so-called "Day-1" operations on February 1, 2002, it took over important system reliability functions across the Midwest ISO's transmission footprint (*i.e.*, the "Midwest ISO Region"). The Midwest ISO assumed responsibility for many of the functions of a regional security or reliability coordinator, functions that had been performed by the North American Electricity Reliability Council ("NERC") Regional Reliability Councils – ECAR, MAIN and MAPP. The Midwest ISO also took over some of the functions that were previously handled by those Midwest ISO Transmission Owners ("TOs") that are the control area system operators. The control area functions that the Midwest ISO assumed included the traditional *pro forma* OATT provision of transmission service, such as the determination of transfer capability, the handling of requests for transmission service and OASIS administration, and transmission or transaction scheduling. The Midwest ISO thus assumed responsibility for evaluating regional security conditions to determine whether requests for transmission service could be accommodated on the transmission system and whether transactions actually scheduled on the grid resulted in flows that remained within or violated various security limits designed to ensure reliable operations. As part of its overall security responsibility, once schedules were submitted, the Midwest ISO became responsible for determining whether and which transmission schedules should be curtailed to maintain flows within the security limits.

Q. WHAT TOOLS DOES THE MIDWEST ISO USE TODAY TO ENSURE FLOWS REMAIN WITHIN SECURITY LIMITS, UNDER THESE "DAY 1" PROCEDURES?

A. Within the Day 1 *pro forma* framework, there are three principal means by which control area operators and regional security coordinators keep flows within safe and secure limits, while keeping the system in balance. They include: (1) control of transmission access through screening and approval (or denial) of transmission requests; (2) real-time dispatch; and (3) curtailments.

Q. PLEASE DESCRIBE THESE DIFFERENT TOOLS.

A. The first principal means is try to screen and deny requests for transmission use that would cause flows to exceed the security limits. This is done through the determination of Available Flowgate Capacity ("AFC") and the process for approving, disapproving, or preempting requests for transmission service. When it became the independent transmission provider for the Midwest ISO region, the Midwest ISO took over the screening and approval of transmission service requests from the TOs and/or their respective control area system operators.

The second principal means is for each local control area[1] that dispatches Generation Resources to use its dispatch to keep flows within limits and maintain system balance (including acceptable voltage and frequency levels) within its control area, as well as maintain agreed-upon flows between adjoining control areas. If flows across any

[1] An important factor in designing a transition for the Midwest ISO region is that there are different categories of "control areas" in the Midwest ISO Region; not all control area operators have the same functions. The focus here is on the control of the real-time dispatch used to maintain system balance, frequency and voltage levels.

transmission element exceed or would exceed the security limits in a pre- or post-contingency condition, the affected control area or areas can redispatch the generation under its control to relieve transmission constraints and bring flows back within secure operating limits. Under "Day 1" procedures, this important coordination function remains almost exclusively within the control of the existing TOs and/or their respective control area system operators; the Midwest ISO did not have this capability when Day 1 operations began and does not yet have this responsibility. That will change with Day 2 operations under this revised Tariff.

The third principal means is for the regional security coordinator – in this case, the Midwest ISO – to determine and monitor the flows across the regional grid and then, if needed, to require that certain transmission uses or schedules be reduced, in accordance with the curtailment rules specified by the NERC under the Transmission Line Loading Relief ("TLR") procedures. Under Day 1 procedures, the Midwest ISO can thus monitor actual power flows, including so-called "loop flows", across the Midwest ISO Region, and if necessary, order affected Midwest ISO and non-Midwest ISO control areas to curtail transactions between the Midwest ISO control areas, as well as transactions that may originate and/or end in control areas outside the Midwest ISO Region. Actual power flows can be different from those forecasted at the time transmission service requests were scheduled.

Q. DID THE MIDWEST ISO'S ASSUMPTION OF THE FIRST AND THIRD MEANS IMPROVE RELIABILITY?

A. Yes, it did, in a qualitative sense. There are five ways in which the Midwest ISO has been able to improve system reliability through taking over these two functions. First, the Midwest ISO instituted a uniform process for calculating Available Flowgate Capacity, the unused transfer capability of specific facilities that are network elements or sets of elements monitored to ensure the reliability of the transmission system. This provided a more precise determination of the service requests that could be safely accommodated. Second, the Midwest ISO performs contingency analysis based upon its ability to observe regional power flows, including contingencies and loop flows that would not be visible to individual utilities. Each element of the electric system has ratings that determine how much current can flow through it without risking damage to or the failure of that equipment. When an element is knocked out of service, the equipment may be costly to replace, and its failure will shift power flows throughout the entire network at the speed of light. If the resulting change in flows is sufficiently severe or not reacted to promptly, other elements impacted by such shifts also may fail and could cause a cascading blackout. For this reason, the power system is operated under contingency planning.[2] Monitoring of the system reveals certain elements (known as constrained elements) that would be overloaded if some other element (known as the contingent element) fails. Midwest ISO operates the system to ensure that if a contingent element fails, the constrained element will not be put unduly at risk. When the Midwest ISO began to operate the transmission system on a regional basis, it was able to identify contingencies that had not previously been monitored. Individual utilities were not always able to observe flows in adjacent systems within the Midwest ISO Region and may not have been aware of contingencies that could be observed from a regional

[2] See: NERC Policy 2, Subsection A, Standard 1, available at: ftp://ftp.nerc.com/pub/sys/all_updl/oc/opman/policy2.pdf.

perspective. Third, the Midwest ISO has implemented sophisticated tools to support regional reliability coordination. Our Carmel control center uses large overhead displays to show real time conditions of the transmission system throughout the Midwest ISO Region. This display has been recently upgraded and now provides a visual link to individual facility one-line diagrams. These one-line diagrams permit reliability coordinators to view real-time data and conditions at individual facilities across the Midwest ISO Region. The Midwest ISO also uses its Flowgate Monitoring Tool (FGMT) to track conditions at key facilities in the network. The FGMT notifies operators when there has been a change in the status that exceeds predetermined limits. For example, if the flow on a key transmission line increases by 15%, that line would be displayed in a different color and move to the top of the operator's screen. The Midwest ISO additionally has implemented a highly sophisticated, real-time computer model of the regional transmission system known as a State Estimator. The State Estimator uses real-time Supervisory Control and Data Acquisition system (SCADA) data supplied by data links to member control areas to calculate the current conditions for the entire transmission system. It does this by calculating values for those points in the system where no actual measurements are available, thus providing a "state estimation" of the system. The Midwest ISO State Estimator calculates a solution reflecting current conditions every 90 seconds. Fourth, given its tools, the Midwest ISO is able to conduct real-time contingency analysis. On every third cycle or every 4.5 minutes, the Midwest ISO State Estimator automatically makes further real-time contingency analysis calculations. These calculations evaluate the impacts of 5,500 contingencies or "what-if scenarios" to identify conditions where the loss of any single network element could cause problems for other facilities. This capability allows the Midwest ISO to relieve congestion without causing more severe constraints elsewhere in the system. While not all reliability coordinators use real-time contingency analysis and others resort to it only when the system is degrading, it is a powerful tool for protecting reliability in a highly integrated system such as that within the Midwest ISO Region. Fifth, the Midwest ISO is able to coordinate outage schedules. Operating on a stand alone basis, utilities may exchange outage planning information with neighboring utilities, but there is nothing to prevent one company from taking a line out of service when its operation is critical to a neighboring utility. The Midwest ISO has a wide regional view and is typically able to propose acceptable alternatives to the control areas involved that protect reliability and minimize the costs of changing outage schedules or altering transactions. And, the Midwest ISO has the authority to order a delay in a line outage or generator maintenance schedule to protect regional reliability.

Q. ARE THERE ANY QUANTITATIVE INDICATORS OF THE RELIABILITY EFFECTS OF THE MIDWEST ISO TAKING OVER THESE TWO FUNCTIONS AS PART OF ITS DAY 1 OPERATIONS?

A. One of the effects of improved monitoring of system contingencies has been a significant increase in number of Transmission Loading Relief (TLR) events. Based on the best data available from the North American Electric Reliability Council (NERC) (which tabulates Level 2 and higher TLRs) in 2000 and 2001, there were just over 1000 TLR logs. That number increased to almost 1500 in 2002 and over 1800 through November of 2003**.** This increase is in large part attributable to the addition of approximately 1000 Midwest ISO TLRs. An increase in TLRs reflects the Midwest ISO's improved ability to identify and avoid potential contingent system instabilities. Assuming conservative estimates of the probability that one or more of these avoided contingencies could have resulted in a loss of load, the value of improved reliability created by Midwest ISO reliability coordination would be very high.

Q. IF THE CONTROL AREA DISPATCH FUNCTION IS A CRITICAL TOOL FOR ENSURING RELIABILITY, WHY DIDN'T THE MIDWEST ISO ALSO ASSUME THIS DISPATCH FUNCTION ON DAY 1?

A. The initial focus of the Midwest ISO was on the provision of non-discriminatory transmission service by an independent transmission provider, including unbiased calculations of AFC, equal access to information on available capacity through postings on OASIS, and nondiscriminatory treatment of all transmission service requests. These services fulfilled the primary obligations of the Midwest ISO as an Independent System Operator ("ISO") under the Federal Energy Regulatory Commission's ("Commission") Orders 888 and 889.

In Order No. 2000, the Commission held that an, "RTO must have the right to order the redispatch of any generator connected to the transmission facilities it operates, if necessary for the reliable operation of the transmission system." And, it expressed the belief that in general, "this control should be through a market where the generators offer their services and the RTO chooses the least cost options."[3] Order No. 2000 did introduce the idea that efficient and non-discriminatory transmission service required the ISO to provide a real-time balancing service, and that this service was interdependent

[3] Order 2000 at p. 318.

with the coordination of real-time power flows. That is, a real-time balancing service cannot, nor should not, be separated from the management of real-time power flows.

The subject Tariff is designed to move the Midwest ISO from Day 1 operational capabilities (based on the *pro forma* notions of providing transmission service) to a more complete and efficient conception of a full service transmission provider, as currently envisaged by the Commission..

However, because the starting point is a Region with multiple control areas and separate control area dispatches, rather than a fully centralized regional dispatch pool (as was present in the Northeast), the Midwest ISO has a much tougher challenge in getting to the goal of a fully functional transmission provider. A transition that recognizes the realities of the Midwest ISO's starting point has been necessary.

Q. HOW DID THE RETENTION OF THE CONTROL AREA DISPATCH FUNCTION BY THE MIDWEST ISO TRANSMISSION OWNERS UNDER "DAY 1" PROCEDURES AFFECT RELIABILITY IN THE MIDWEST ISO REGION?

A. Under today's Day 1 procedures, the Midwest ISO does not coordinate a regional dispatch for the Midwest ISO Region. Most control area operators retain the dispatch function for their respective control areas, providing real-time dispatch/balancing and redispatch within the confines of their control area. Each control area's dispatch, however, is limited to that necessary to serve local loads and to support firm transmission service on the control area's local footprint; it is not available or used to support transmission service across the regional footprint except to the extent that the local TO has sold firm transmission service on the TO's own system. Given this structure of local dispatches, the coordination of flows between control area operators is limited (usually on an hourly basis, whereas the dispatch is typically done on a five-minute basis), transactions seldom fully optimize the use of the transmission system and dispatch of resources and actual power flows, including congestion and regional loop flow effects are managed using less efficient and precise TLR procedures.

The balkanized structure of the current system requires a substantial degree of communication and coordination between the separate control areas and between each control area and the Midwest ISO (or any entity that has the regional security coordinator function). Any coordination or communication failure in this highly complex arrangement (with so many entities managing what is, in reality, a single interconnected grid spanning a huge portion of the North American continent) can have extremely serious consequences.

The current separation of functions between Midwest ISO and the multiple control areas has at least two important implications. First, because each control area functions somewhat independently, the perception of the availability of transmission capacity between the control areas tends to be static. However, the volume of transactions that can be accommodated on any given grid is not static; it depends on all other uses of the grid and the ability to redispatch generation to relieve transmission constraints (including congestion) and thereby accommodate further transactions and flows. In real-time, the actual transfer capabilities of the grid do not match a pre-defined, fixed level of transfer capability (forecast with necessary conservatism to protect system reliability). However, under the current *pro forma* tariff, the Midwest ISO cannot accommodate requests for transmission service by assuming the availability of congestion redispatch, because, while the Midwest ISO assesses Available Flowgate

Capacity ("AFC") and transmission service requests, the individual control areas control their respective dispatches and are under no obligation to redispatch their systems to accommodate all transactions. Their reluctance to provide redispatch is understandable, given the fact that in the absence of market-based prices for redispatch, there is no transparent and fair method for either offering or pricing redispatch. In other words, reliable and efficient use of the grid requires that the provision of transmission service be connected directly with a mechanism that aligns the physics of redispatch with the economic consequences, *i.e.,* the ability to offer and price congestion redispatch when it is necessary to accommodate a transaction while keeping flows within operating security constraints.

Q. DOES THIS MEAN THAT THE SEPARATION OF TRANSMISSION SERVICE FROM DISPATCH LEADS TO THE MORE FREQUENT NEED FOR TLRS?

A. Yes. If economic redispatch is not available to support a given transmission service, then transmission use that leads to violations of operating security limits must be curtailed through some means, in most cases, by use of TLR curtailments. As the Commission is well aware, physical rationing through the imposition of a TLR has many disadvantages. Most importantly, TLRs are inherently inefficient, because they take little account of economics, which leads to the curtailment of otherwise economic transactions and thus to an inefficient utilization of the grid. If economic redispatch is not available to support transmission service, then the only practical way to avoid excessive use of TLRs after the fact is for the transmission provider to be overly conservative in granting transmission service before the fact, a solution that clearly leads to the an underutilization of the physical grid. Hence, separating the provision of transmission service from the dispatch function leads either to uneconomic use of the grid or under-utilization of the grid (or, possibly, both). These functions were once integrated within vertically integrated utilities, but they became artificially separated in early attempts to ensure open access transmission service. These adverse consequences can be avoided by recombining the transmission service and security-constrained economic dispatch functions in an independent transmission provider and making the total service available at a transparent price that grid users can compare with the economic value they place on continuing their transactions without curtailments.

Even if there were no issues in providing non-discriminatory service, recombining the two functions of dispatch and transmission service at the local control area level would perpetuate the inter-control area coordination problems while doing nothing to solve the need for a broader regional perspective that can internalize and better manage loop flows and congestion. The better solution, from the perspective of both efficient grid utilization and system reliability, is to combine the provision of transmission service and the dispatch functions at the regional level and have these integrated functions operated by an impartial and independent transmission provider. That is essentially what the Midwest ISO is proposing to begin with this filing for Day 2 operations.

Q. HOW DOES RELIANCE ON TRANSMISSION LOADING RELIEF PROCEDURES LEAD TO UNDERUTILIZATION OF THE TRANSMISSION GRID?

TLRs inherently rely on imprecise estimates and cannot accurately reflect system interactions. Under NERC TLR procedures, the impact of control area to control area transactions and local generation on constrained facilities is estimated using power flow distribution factors. Power flows estimated using these procedures do not consistently correspond to actual power flows. Moreover, TLRs are issued to curtail specific transmission transactions. When a transaction is curtailed the affected control areas have choices about how to redispatch generation, curtail load, and/or reconfigure their systems to comply. Each of these actions takes time, occurs against a background of constantly changing power flows, and affects power flows on multiple flowgates. Because the parties' responses to the curtailment are not coordinated, the simultaneous impact of the responses to a TLR cannot be precisely predicted. As a result, it is not possible for reliability coordinators to use TLRs to maintain power flows at operating security limits on a sustained basis. Some amount of transfer capability goes unutilized during TLR events.

Q. TO WHAT EXTENT IS THE GRID UNDERUTILIZED AS A RESULT OF RELIANCE ON TRANSMISSION LOADING RELIEF PROCEDURES?

A. The Midwest ISO has recently analyzed actual flowgate utilization from two samples of TLR events in separate areas of its footprint. For a comparatively less constrained portion of the footprint (Kentucky), we examined a sample of 28 TLR events and found that on average 7.78% of available flowgate capacity was actually unused during these TLR events. We also studied 198 TLR level 3 – 5 events in a frequently constrained portion of our footprint (Wisconsin and Upper Peninsula control areas). We found the amount of unused capacity during TLRs on affected flowgates in this region equaled, on average, 11.407% of available flowgate capacity. In both portions of the footprint, the inability to fully utilize the capabilities of the transmission system during periods of high demand for transmission services has significant economic costs.

Q. IN WHAT OTHER WAYS IS RELIANCE ON TRANMISSION LOADING RELIEF PROCEDURES TO MANAGE CONGESTION ECONOMICALLY INEFFICIENT?

A. Under NERC TLR procedures, when a curtailment is needed, all transactions in the selected service priority that impact the constrained flowgate by more than the minimum curtailment threshold (5%) are cut on a pro-rata basis. And, operators are not able to curtail only that portion of the power flow from each transaction that affects the constrained flowgate. Thus, if only a small portion of the energy from a given transaction is passing through the constrained flowgate, the entire transaction may be curtailed, having a potentially large economic impact on the parties. Following NERC procedures, the Midwest ISO, for example, has had to cut a 135 MW transaction to achieve as little as 7 MW of relief on a constrained flowgate. In the absence of a market, it is not possible to determine the economic impact of curtailing any particular transaction. However, it is not difficult to imagine cases in which the costs of implementing a TLR greatly exceed the cost of a comparatively small redispatch that could provide the same reduction in flows over the constrained flowgate.

Q. TO WHAT EXTENT WILL THIS FILING INTEGRATE DISPATCH AND TRANSMISSION FUNCTIONS AT THE MIDWEST ISO LEVEL?

The Midwest ISO will have a regionally-coordinated, security-constrained economic dispatch when Day 2 operations begin. It will dispatch generation based on price bids into the Energy Market.

Q. HOW WILL COMBINING THESE FUNCTIONS AT THE REGIONAL LEVEL ALLOW THE MIDWEST ISO TO ACHIEVE THE GOALS OF MORE EFFICIENT GRID UTILITIZATION AND ENHANCED RELIABILITY?

A. If transmission service and dispatch were combined and centrally coordinated by the Midwest ISO, then the Midwest ISO could provide a regional dispatch to support additional transmission service that might otherwise not be scheduled or allowed, or if allowed, curtailed under a TLR. If transmission service and dispatch were centrally coordinated by the Midwest ISO, then the Midwest ISO could offer transmission service throughout the Midwest ISO Region and back that service with a regionally coordinated redispatch of generation whenever that was needed to keep flows within operating security limits. Of course, the Midwest ISO would still need an unbiased mechanism with which to offer and price this redispatch service, which leads to the need for pricing mechanisms that define the marginal cost of redispatch, as I discuss in Part III of my testimony. But the important point is that if there is no regionally coordinated dispatch, TLRs on a wide scale become unavoidable.

Q. PLEASE DESCRIBE THE PRINCIPAL FEATURES OF THE TARIFF THAT WILL ENHANCE REGIONAL RELIABILITY.

A. As explained above, under the revised Tariff the Midwest ISO will coordinate a bid-based regional dispatch and use that dispatch to support transmission service and economic transactions within and between the Midwest ISO and other regions. The real-time dispatch will also provide the basis for the essential balancing market, as required by Order 2000. The balancing service will be done on a regional basis and will also be coordinated with balancing provide by each control area dispatch, with local area regulation provided by the local control area to fine tune the balancing service.

As an independent transmission provider, the Midwest ISO will continue to offer transmission service on a non-discriminatory basis. However, unlike the current *pro forma* tariff arrangements, the amount of transmission service that the Midwest ISO will provide will not be limited by a static definition of transfer capability but will instead accommodate additional requests for transmission service that can be supported by the availability of a regional security-constrained dispatch (*i.e.*, "redispatch"). As long as there are sufficient voluntary generation offers to the Midwest ISO dispatch to allow it to arrange a security-constrained economic dispatch, the Midwest ISO's dispatch will accommodate all transmission service requests, provided that the transmission customers are willing to pay the Midwest ISO's transmission usage charges and all generation and load schedules. For each transaction scheduled on the Midwest ISO-controlled grid, these usage charges will reflect the marginal cost of any changes in the dispatch (redispatch) that are needed to accommodate that particular transaction within the grid's security limits. Parties willing to pay the usage charge will receive transmission service, including the redispatch service necessary to accommodate that service. For parties unwilling to pay the usage charge to accommodate their transactions, the Midwest ISO will decline their schedules, and no redispatch will be needed or performed for those declined transactions.

This approach means that for most "internal" transactions -- those that originate (source) and end (sink) in the Midwest ISO Region -- there will be little or no need for TLRs. For these transactions, the Midwest ISO will only resort to using TLR procedures in the event that there are insufficient dispatch offers from generators, such that the Midwest ISO cannot arrange a security-constrained economic dispatch to accommodate the transmission schedules. The result should be a substantial reduction in the use of TLRs within the Midwest ISO region.

Q. HOW WILL THE USE OF A REGIONAL, BID-BASED SECURITY-CONSTRAINED DISPATCH AND THE RESULTING REDUCTION IN THE USE OF TLRS ENHANCE RELIABILITY?

A. A security-constrained dispatch to prevent security violations before the fact is a vastly superior mechanism for achieving reliable operations than reliance on cumbersome TLR procedures to relieve constraint violations after the fact. While it is possible to maintain reliability through primary reliance on TLRs and other elements of the current system, just as the Midwest does today, it is becoming increasing inefficient and difficult to do so because of the volume of transactions, particularly transactions between control areas, and the increasing need for TLRs. Moreover, continued reliance on TLRs as the primary tool for coordinating power flows within security limits is becoming increasingly risky. TLRs are a cumbersome, time-consuming, imprecise and sometimes unreliable tool for keeping flows within security limits. In particular, TLRs require substantially greater efforts to communicate and coordinate between the regional security coordinator, the affected control areas, and the affected parties that must be notified of the need for curtailment and then take the necessary actions to curtail their injections and/or withdrawals, compared with market mechanisms. Even when the coordination is accomplished, this is a time-consuming process that can take a half hour or more. The final results are somewhat uncertain and rarely match the precise need for congestion relief.

The lack of precision and the delay in relieving grid security violations might be tolerated if TLRs were only occasionally required. However, the growth of TLRs within the Eastern Interconnection makes continued reliance on TLRs as one of the principal reliability tools increasingly problematic. It is clear that the TLR mechanism cannot work fast enough or precisely enough to provide the kinds of quick responses that system operators sometimes need to avoid rapid deterioration of grid conditions during extreme conditions. No TLR mechanism could have prevented the events of August 14, 2003.

In contrast, a regionally coordinated security-constrained dispatch can: (1) be largely automated, (2) avoid constraint violations before they happen, (3) solve congestion problems much more quickly when they arise, and (4) do so simultaneously across the dispatch region. Further, because the generators participating in the dispatch are doing so because they volunteered to be dispatchable, there is a much greater likelihood that the generators will respond to dispatch instructions and change their outputs so as to relieve congestion and ensure that flows stay within security limits, while maintaining system balance. Finally, security-constrained dispatch gives reliability coordinators the ability to exercise precise control in real time. The effects of dispatch instructions will be predictable and can be continuously updated to ensure power flows remain at or below operating security limits.

Of course, the willingness of generators to follow dispatch instructions is strongly influenced by the pricing mechanisms that an RTO uses to compensate generators for the energy they produce and the changes they make in their output in response to dispatch instructions. Here, pricing mechanisms that reflect actual conditions on the grid, particularly the use of locational marginal pricing ("LMP") of the dispatch (and hence of any redispatch used to relieve congestion), play an essential role in supporting the use of regional dispatch to maintain reliable operations. In other words, under the Midwest ISO Tariff, the pricing mechanism will be consistent with and support reliable dispatch, and the security-constrained dispatch will maintain reliability with more assurance while substantially reducing the need for cumbersome TLRs. The essential role of the LMP pricing mechanism is more fully addressed in Part III of my testimony and in Dr. Hogan's Prepared Direct Testimony.

Q. WILL THE MIDWEST ISO'S TARIFF ELIMINATE THE NEED FOR TLRS?

A. No. Transmission service between the Midwest ISO and neighboring regions, and transmission service that has sources and sinks outside the Midwest ISO Region but causes loop flows through the Midwest ISO Region, may still be subject to TLRs. This is because the Midwest ISO may not be able to arrange a security-constrained dispatch to support that transmission service or, even if it could provide redispatch to accommodate loop flows within the Midwest ISO Region, there may be no mechanism to hold the external transmission customers responsible for the Midwest ISO's marginal costs of redispatch. The Midwest ISO members should not be required to subsidize these redispatch costs to support transactions outside the Midwest ISO Region. Solving this problem will require inter-regional coordination of the dispatch, common redispatch pricing and settlements between the regions. The Midwest ISO and PJM have been working to build the infrastructure necessary to achieve this "seamless" operation between Midwest ISO and PJM, as part of the goal of creating a joint and common market between the two RTOs, including a December 31, 2003 Joint Operating Agreement that was conditionally approved by the Commission on March 18, 2004. Seamless operations between Midwest ISO and other non-ISO regions must await further developments within those other regions.

Q. HOW ELSE WILL A REGIONALLY COORDINATED DISPATCH ENHANCE RELIABILITY IN THE MIDWEST?

A. In conjunction with the development of a regional dispatch system, and as part of its responsibilities as regional security coordinator, the Midwest ISO has been developing additional tools, such as a "state estimator", that can allow the Midwest ISO to monitor flows and conditions across the entire Midwest ISO Region, as well as flows and conditions in neighboring systems. These tools allow Midwest ISO to "see" the entire system and become aware almost immediately whenever problems occur anywhere on the system. The virtual real-time data provided by such tools will enable Midwest ISO's region-wide coordinated dispatch to deal quickly and effectively with imbalances, security violations or other problems anywhere in the region.

The Midwest ISO's enhanced regional capabilities, and use of more precise and responsive reliability tools, such as a regional state estimator and a regionally-coordinated dispatch, will gradually replace the current system that relies on multiple control areas, multiple dispatch, and extensive coordination between those control areas. As the Midwest ISO assumes more coordination functions at the regional level, coordination and communication requirements will become more internalized, thus reducing the need for extensive coordination between the multiple control areas. From a reliability standpoint, this will result in a reduction of "seams" between the control areas.

Of course, the Midwest ISO will still need to communicate and coordinate operations with neighboring systems; however, there will be fewer independently operated systems to coordinate than there are today. Moreover, as other regions achieve the level of regional coordination and dispatch that the Midwest ISO is developing, the Midwest ISO and those regions will be able to pursue even more coordinated operations, just as the Midwest ISO and PJM are developing today with the development of a joint and common market for the combined Midwest ISO-PJM region.

Q. WILL THE MIDWEST ISO ADMINISTER A UNIT COMMITMENT PROCESS TO ENHANCE RELIABLE OPERATIONS?

A. Yes. As part of the Day-Ahead Energy Market process, the Midwest ISO will accept 3-part supply offers from generators, reflecting each generator's start-up fees, the fees of operating at zero generation levels, and the fees for incremental energy. The Midwest ISO will use these 3-part offers to optimize the commitment of resources needed for real-time operations. This mechanism will ensure that sufficient generators are available in real time to meet the Midwest ISO's forecast of real-time loads. I discuss this feature in greater detail in Part IV.7.

III. THE MARKET MECHANISMS THAT THE MIDWEST ISO WILL COORDINATE UNDER THE TARIFF WILL SUPPORT RELIABILITY AND ENHANCE ECONOMIC TRADING WITHIN THE MIDWEST REGION.

Q. PLEASE DESCRIBE THE KEY MARKET MECHANISMS THAT THE MIDWEST ISO WILL COORDINATE.

A. Under the proposed Tariff, the Midwest ISO will coordinate both Real-Time and Day-Ahead spot markets for energy, and associated markets for at least some ancillary services. (Regulation will still be provided by the local control areas for an interim period, so there will not be Midwest ISO-coordinated markets yet for that ancillary service.) The Real-Time Energy Market will function as the real-time "balancing market" required by Order 2000. This market will be based on voluntary supply offers to sell and demand bids to purchase submitted to the Midwest ISO by Market Participants, including both generators and participating loads. The Midwest ISO will use the voluntary offers and bids to arrange a security-constrained, economic dispatch for each market interval. The market interval for the Day-Ahead Energy Markets will be hourly; for the Real-Time markets, the dispatch intervals will be every five minutes.

Once the Midwest ISO defines a security-constrained economic dispatch for a given market/dispatch interval, the Midwest ISO will determine market-clearing prices in each market for each product, using the principles of LMP, which is the same pricing tool the Commission recommended in Order 2000 and has approved for use in PJM, the New York ISO and ISO New England. LMP defines the marginal cost of serving the next increment (1 MW) of load at each location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. Under LMP, the market-clearing prices used for settlements in the Midwest ISO-coordinated markets will differ between some locations whenever there is congestion on the Midwest ISO-controlled grid. Prices will also differ between locations due to losses; the LMPs will include the effects of marginal losses, just as they do in New York. The Midwest ISO will administer a settlement system for all spot sales and purchases in the Midwest ISO markets and for transmission usage charges.

Q. OTHER LMP-BASED MARKETS HAVE SOME FORM OF FINANCIAL TRANSMISSION RIGHTS ("FTRS") TO ALLOW PARTIES TO HEDGE THE

COSTS OF CONGESTION. WILL MIDWEST ISO ALSO HAVE SOME FORM OF FTRS?

A. Yes. Midwest ISO will administer a system of financial transmission rights ("FTRs") to support the use of LMP for pricing congestion and transmission usage and to allow parties to lock in transmission prices in advance of real-time operations. Each FTR is defined as running from one pricing location to another pricing location (*e.g.,* from location A to location B). These pricing "locations" may be individual nodes or buses on the Midwest ISO grid, as well as aggregations of nodes/buses that comprise pricing regions (such as service areas or sub-regions defined by states for retail rate purposes) or trading hubs established by the Midwest ISO. The FTRs are thus identical in concept to the FTRs used in PJM and ISO-New England and the Transmission Congestion Contracts ("TCCs") used in New York.

As in those other markets, at market launch, the Midwest ISO will use only FTR "obligations." FTRs in the form of "options" will be offered and supported by the Midwest ISO at a later date, but not initially. This is consistent with the pattern seen elsewhere. The Midwest ISO will also administer both yearly and monthly auctions of "residual" FTRs. During these auctions, FTRs can be bought and sold on a competitive basis. The FTR allocation system is described more fully in the testimony of Midwest ISO expert witness Dr. Paul Gribik.

As in other LMP-based spot markets, FTRs allow Market Participants to hedge the day ahead costs of congestion resulting from the Midwest ISO's security-constrained dispatch, whether those costs are reflected in the congestion components of the LMPs for spot purchases and sales or the resulting transmission usage charges for point-to-point transactions scheduled in the spot markets. The holder of an FTR obligation is entitled to the difference in value between the congestion component of the LMP at the sink of the FTR and the congestion component of the LMP at the source of the FTR. Because this settlement value exactly matches the way in which the congestion portion of the transmission usage charges is defined, the holder of an FTR from location A to location B can exactly offset ("hedge") the congestion part of the usage charge for the same transaction from A to B. There will also be a marginal losses component in the LMP charge, which I describe in Part IV.2.

Q. WHY DID THE MIDWEST ISO PROPOSE A SYSTEM OF FTRS INSTEAD OF PHYSICAL TRANSMISSION RIGHTS?

A. The primary advantage of organizing dispatch around financial, as compared to physical, rights to the grid is that FTRs do not restrict an economic dispatch. Because the settlement value of any FTR does not require that the FTR match the FTR holder's physical transaction (or any other party's transactions), parties are free to change their physical injection and withdrawal quantities and points and their point-to-point schedules in any way that is economically beneficial, including responding to economic dispatch instructions from the Midwest ISO, without having to realign the portfolio of transmission rights they hold in order to ensure access to the grid. In strict physical rights systems, the rights must match the transaction to guarantee physical access, and the value of any rights not "used" is lost. For example, a party may hold an FTR from location A to location B but for other economic reasons (or outages) decide to change its injection and/or withdrawal points to X and Y. It may schedule this revised transaction without obtaining matching FTRs. The party will still receive the market value of its A-to-B

FTRs, which will be settled on the basis of the LMPs at A and B, while the party pays for its actual transmission usage (from X-to-Y) based on the LMPs at the actual injection and withdrawal locations. (This is equivalent to selling transmission from A-to-B and buying transmission from X-to-Y.) The A-to-B FTR still has value as a hedge, which may be the same as, less than, or more than the congestion part of the transmission usage charges the party incurs for its X-to-Y transaction. Thus, parties may seek to obtain matching FTRs (*i.e.*, they may try to "back-to-back" energy sales with FTRs), or they may acquire portfolios of FTRs that are very different from their expected transactions; the hedging mechanisms need not match the transactions, and because they have settlement value even for transactions that don't match, they do not discourage economic dispatch. In addition, because FTRs retain their settlement value and are not "use it or lose it," they can be traded to other parties with very different transactions.

Q. WILL THE MIDWEST ISO ALSO COORDINATE SHORT-RUN MARKETS FOR BUYING AND SELLING TRANSMISSION USAGE AND/OR TRANSMISSION RIGHTS?

A. Yes. The LMP system for pricing congestion defines locationally different prices for energy at each location on the grid that is affected by congestion. Parties could therefore sell energy at one location at its respective LMP and purchase energy from another location at its respective LMP, using separate spot market transactions. However, simultaneously selling energy at one location (point A) and buying the same amount of energy at another location (point B) is equivalent to buying transmission from point A to point B. The spot price of transmission usage is thus defined by the difference in the locational price at B minus the locational price at A. This price difference equals the marginal cost of redispatching the system – that is, the change in the bid-based cost of the security-constrained economic dispatch needed to accommodate the transmission usage from A-to-B.

In the context of the redispatch option discussed above for maintaining reliability, the LMP mechanism means that when a party schedules transmission from A-to-B, the Midwest ISO can easily define the marginal cost (which is based on the voluntary offers received from resources) of accommodating that transmission schedule through the Midwest ISO's security-constrained dispatch and charge that price to the party scheduling the transmission. LMP thus provides a convenient, transparent and efficient way to charge all parties the marginal costs that their transactions impose on the grid. When parties schedule transactions from one location to another and agree to pay this LMP-defined marginal cost of usage, they are, in effect, "buying" transmission usage in the Midwest ISO-coordinated spot market.

Q. CAN MARKET PARTICPANTS ALSO "SELL" TRANSMISSION THROUGH THE MIDWEST ISO-COORDINATED MARKETS?

A. Yes. Just as occurs in other LMP-based markets, FTRs will be settled in the Midwest ISO-coordinated Day-Ahead Energy Market, based on the Day-Ahead Energy Market's LMP clearing prices. When parties settle their FTRs at Day-Ahead prices, they are, in effect, "selling transmission usage" in the Day-Ahead Energy Market at day-ahead prices.

Similarly, parties that schedule transmission in the Day-Ahead Energy Market and pay the marginal cost of redispatch (the transmission usage charge defined by LMP differences) are effectively buying transmission in the Day-Ahead Energy Market. But if they fail to implement their schedules in the Real-Time Market, they pay for imbalances at the receipt and delivery points at the respective LMPs; when they do this, they are effectively "selling back" their unused transmission in the Real-Time Market at the real-time LMP clearing prices.

Q. WHY DID THE MIDWEST ISO DECIDE TO ADD A DAY-AHEAD MARKET?

A. There are a number of advantages in having the Midwest ISO coordinate a Day-Ahead Energy Market. This Market provides another opportunity for parties to lock in prices for energy, reserves and/or transmission in advance of real-time, allowing them to better align their long-term forward positions with the positions they expect to carry into real time. The Day-Ahead Energy Market allows loads to purchase any uncontracted requirements in advance, without waiting until real time, and it allows generators to sell uncontracted output in advance, without waiting until real time. Having locked in day-ahead prices for energy and congestion, parties then have several hours to prepare for the next day's operations and/or to consider further changes in response to their expectations of real-time conditions. While the Day-Ahead Energy Market can be described as "financial" in that actual delivery of energy does not occur until the next day, it also has a physical element since the Midwest ISO will be obtaining information from participants about how they expect to behave in real time. This information can aid in achieving efficient unit commitment and providing reliable grid operations.

Q. CAN THE DAY-AHEAD MARKET ENHANCE DEMAND RESPONSE?

A. Yes. For example, large customers or load-serving entities can purchase any portion of their uncontracted energy needs in the Day-Ahead Energy Market and then use the time between the close of the Day-Ahead Energy Market and real time to determine whether they wish to curtail consumption in real time, effectively selling back the energy they bought day ahead in the Real-Time Market. If tight supplies and high prices were expected in real time, this strategy would give the loads more opportunities for deciding whether or not to buy/consume energy.

The added flexibility provided by the Day-Ahead Energy Market is expected to allow many price-sensitive loads to pursue demand-side options they might not otherwise pursue if there were only a real-time balancing market. In particular, the Midwest ISO expects to see more demand response from price-sensitive loads participating in the Day-Ahead Energy Market than it would otherwise have seen if loads had to be dispatchable on a five-minute basis in the Real-Time Market. Of course, loads could always wait until real time and respond to Real-Time Market prices, but many loads may not be able to change their consumption patterns on such short notice. The Day-Ahead Energy Market gives these loads more time to decide what actions make economic sense and to get ready.

Q. WHY IS GREATER DEMAND-SIDE RESPONSIVENESS IMPORTANT?

A. Increased responsiveness by price-sensitive loads has several major benefits. Explicit demand bids and actions taken by price-responsive loads helps the ISO meet loads reliably and define prices during periods of scarcity or near scarcity. This helps to mitigate shortages and mitigate peak period prices. For the same reasons, demand-side response during peak and/or shortage conditions reduces both the incentive and ability of generators to exercise market power. Virtually all market design economists strongly recommend that ISOs include measures, such as Day-Ahead Energy Markets, that facilitate and encourage increased demand-side response to market prices. This mechanism works best, of course, when larger, price sensitive loads with appropriate meters are actually exposed to real-time spot prices at their locations. To achieve the full benefits, state regulators should allow or require such loads to be settled for at least their marginal usage at real-time nodal prices.

Q. HOW DOES PRICING THE DISPATCH USING LMP AFFECT THE MIDWEST ISO'S ABILITY TO ENSURE RELIABLE OPERATIONS?

A. The use of LMP will enhance Midwest ISO's ability to ensure reliable operations. I have already explained how the Midwest ISO's ability to offer redispatch will improve reliable operations compared to a system that must rely primarily on TLRs. The LMP methodology is the necessary mechanism for pricing the marginal cost of redispatch, so that grid users can be properly charged for the costs they impose on the system; this allows the Midwest ISO to offer redispatch in support of reliability without fear of cross subsidies. LMP also sends the correct price signals to those generators whose output must be raised or lowered in the redispatch to bring flows back within security limits. For these two reasons, LMP is essential to implementing this more effective reliability tool.

There are other reliability benefits from LMP. LMP encourages generators to follow the Midwest ISO system operators' dispatch instructions. It allows the Midwest ISO to manage a large portion of the congestion in the Day-Ahead Energy Market, leaving fewer problems to deal with in real time. LMP-based charges for transmission usage send efficient price signals about congestion, losses and usage that tend to discourage transactions that worsen congestion and losses and encourage transactions that reduce congestion and losses. Finally, LMP eliminates the gaming of market offers and bids that tend to plague markets that use alternative pricing approaches, such as zonal or uniform pricing.

Q. HOW DOES LMP ENCOURAGE GENERATORS TO FOLLOW DISPATCH INSTRUCTIONS?

A. The LMP prices support reliable dispatch because the prices used for settlements are consistent with the actual dispatch, the grid conditions faced by that dispatch (including the actual constraints that are binding in that dispatch, given grid conditions), and the offers and bids of the participants. For example, if the LMP at a generator's location is $30, and the generator is not dispatched, it means that the generator's offer was above $30, so it has no incentive to generate. If the LMP at that location was at or above the generator's offer, the generator would be dispatched and the LMP would provide an incentive to operate up to the level that corresponds with its offer price. LMP payments thus encourage generators to operate at the levels needed by the ISO to maintain reliable operations. Unlike other pricing systems, in which the "clearing" prices can be inconsistent with the dispatch for any given generator, generators paid at LMP prices always have the correct incentives to follow dispatch instructions.

Q. HOW WOULD LMP ALLOW THE MIDWEST ISO TO MANAGE CONGESTION IN THE DAY-AHEAD MARKET?

A. The Midwest ISO will determine LMPs for all spot sales and purchases and all transmission schedules accommodated in the day-ahead security-constrained dispatch. Midwest ISO will thus manage congestion in the Day-Ahead Energy Market and define usage charges that reflect the marginal redispatch costs for day-ahead transactions. Parties will thus be able to lock in congestion costs in the Day-Ahead Energy Market, thus providing one of the incentives for scheduling in the day-ahead period, rather than waiting until real time. To the extent that parties then follow their day-ahead schedules, the Midwest ISO will not have to manage their congestion in real time, reducing the grid problems that must be addressed in real time.

Q. HOW DOES LMP DISCOURAGE PARTIES FROM SCHEDULING TRANSACTIONS THAT WORSEN CONGESTION WHILE ENCOURAGING PARTIES TO SCHEDULE TRANSACTIONS THAT REDUCE CONGESTION?

A. Every transmission usage will be priced at the LMP-based marginal cost of the dispatch. Transmission usages that cause or worsen congestion will pay corresponding transmission usage charges that reflect the marginal cost of redispatching to accommodate those transactions. The more that transmission usage creates congestion and increases the LMP price differences, the more parties that use the congested lines will pay, thus discouraging parties from scheduling transactions that cause security limits to be violated and require redispatch. Conversely, some transmission usages will create counter-flows that reduce or relieve congestion and reduce or eliminate the need for redispatch. This will be reflected in reduced differences in the LMPs, and in some cases, by negative differences, thus resulting in payments to scheduling parties for reducing congestion. In other words, parties that schedule and implement transmission schedules that reduce or eliminate congestion will be compensated under LMP for their actions and thus encouraged to schedule transactions that bring flows back within secure limits.

Q. HOW DOES LMP ELIMINATE OFFER AND BID "GAMING" OR OTHER MARKET MANIPULATION?

A. The alternatives to LMP for pricing spot energy and transmission are either some form of "zonal" pricing or "uniform" pricing. Other ISOs have tried these alternatives and eventually abandoned them in favor of LMP. Uniform pricing was used in the original PJM tariff (from April 1997 to April 1998, when it was replaced by LMP) and in the original tariff for ISO New England until 2003, when it was replaced by LMP; uniform pricing is still used in Ontario, Canada and is the source of several market design issues in that market. Zonal pricing has been tried in California and ERCOT, and both single-state regional entities are now in the process of replacing their zonal pricing systems with LMP. These experiences have shown in various forms that the non-LMP pricing mechanisms require a system of side payments to generators to encourage them to follow dispatch instructions. One set of side payments must be paid to generators that are constrained off (essentially paying them not to run when running would worsen congestion, even though their offers are below the uniform or zonal settlement price). Another set of payments must be paid to constrained-on generators to encourage them to run when running would otherwise be uneconomic, given their offers in relationship to the settlement prices. Without LMP market-clearing prices to encourage generators to follow dispatch, the uniform or zonal prices by themselves are inconsistent with the generator offers and/or inconsistent with a reliable dispatch, thus requiring side payments to counteract the improper incentives. However, experience in these and other markets has shown that even if the side payments succeed in inducing generators to follow dispatch instructions, the side payments are themselves highly susceptible to manipulation or "gaming" by generators, thus encouraging generators to deviate from offers based on marginal costs.

Gaming of offers to manipulate constrained-off and constrained-on side payments was a pervasive problem in the California market but has also occurred in all other non-LMP markets to some degree. The necessary structure of the side payments encourages generators either to bid below marginal costs or above marginal costs, to maximize the side payments. This requires constant oversight by market monitors and various technical "fixes" that themselves have unintended side effects. Alternatively, if the ISO attempts to limit or eliminate the side payments, it incurs the risks that generators will again fail to follow dispatch instructions. Rather than experiment further with pricing mechanisms that have proven to be highly problematic in other regions, Midwest ISO simply chose to move directly to the LMP approach that has proved successful in the Northeast ISO markets.

Q. DOES LMP ALSO HELP ALLOCATE THE GRID EFFICIENTLY?

A. Yes. By charging each transaction the marginal cost of any redispatch necessary to accommodate that transaction, LMP sends economically efficient price signals about the value of each transmission usage anywhere on the grid. Parties whose transactions have sufficient value and are therefore willing to pay the marginal cost of usage are thus allocated access to the grid, whereas parties whose transactions have insufficient value will decline to pay the usage charge and not use the grid. The LMP-based usage charges will thus allocate grid usage efficiently to those with the highest value transactions.

Alternatively, if the Midwest ISO used some other (non-LMP) pricing mechanism to charge for grid usage, it would not be possible to allocate grid usage efficiently, and the demand for transmission would tend to produce reliability concerns that would have to be addressed through some other non-market, administrative restrictions. For example, during the period in which it used uniform pricing in 1997-98, PJM experienced many occasions when parties were encouraged to use congested transmission because they were not required to pay the marginal cost of redispatch. In effect, redispatch costs were socialized across all grid users by the uniform pricing system, so that transactions that caused or exacerbated congestion were being subsidized for their redispatch costs by other parties whose transactions did not cause or exacerbate congestion. In addition, when parties were not required to pay the marginal costs of their usage, they were encouraged to self-schedule transactions and avoid the ISO's dispatch, resulting in a loss of dispatch control. Without an LMP-based mechanism to charge each party for the costs its transactions imposed on the system, it is my understanding that PJM had difficulty maintaining a reliable dispatch and had no equitable way to allocate grid access other than through some arbitrary method. To limit the degree of cross subsidies and discourage transactions that created "internal" congestion, PJM chose to limit access for some parties (external transactions) in order to protect other parties ("internal" transactions). The result was a barrier to inter-regional trading but with no means to determine whether the prohibited transactions were more or less valuable than the allowed transactions.

Q. HOW WILL MIDWEST ISO'S USE OF LMP INFLUENCE INVESTMENTS IN GENERATION?

A. Investments in new generation are influenced by many factors, including the overall expected level of prices under anticipated demand and supply conditions. Decisions to locate new or expanded generation, or to retire or maintain existing generation at a given location are also affected by many factors that reflect the difficulty or costs of siting. That said, all other factors being equal, paying each generator the LMP for its injections at each location will tend to encourage new resource additions more at those locations with higher LMPs than at those locations with lower LMPs. The higher LMPs will tend to be at locations where there is less supply relative to demand, so LMP-induced resource additions at those locations will tend to increase supply competition, lower prices, reduce congestion and mitigate market power. Conversely, lower LMPs will tend to be at locations where there is more supply relative to demand, so LMP-induced resource additions at those locations would tend not to occur or occur less. At locations that are already export limited because of congestion, the LMP incentives will tend to discourage investments that make matters worse. The LMP incentives will thus tend to make supply and prices more competitive at those locations that need it and work to reduce congestion where it is currently uneconomic.

Q. HOW WILL MIDWEST ISO'S USE OF LMP INFLUENCE INVESTMENTS IN DEMAND-SIDE OPTIONS?

A. Areas with low LMPs will tend to attract more loads and/or encourage existing loads to use more. Areas with higher LMPs will tend to attract less new load additions (all other factors being equal) and send price signals to loads about the value of demand-side reductions when prices are higher than the value of consuming. These incentives will thus promote efficient demand-side responses.

Q. HOW WILL MIDWEST ISO'S USE OF LMP INFLUENCE INVESTMENTS IN TRANSMISSION?

A. The LMP-based usage charges will make the marginal cost of redispatching generation to relieve congestion fully transparent. Parties' willingness to pay this marginal cost signals their willingness to pay for congestion, given the value of their transactions. At the same time, parties' willingness to purchase FTRs (in secondary markets now and in forward FTR auctions in the future) to hedge congestion costs will reveal a Market Participant's willingness to pay to avoid congestion charges. Together, LMP-based usage charges and forward prices for FTRs whose value reflects expected LMP prices will tend to reveal the value of congestion and hence the value of reducing congestion through various means. Transmission upgrades are one means to reduce congestion; locating generation in load pockets is another; expanding demand-response in load pockets is a third; and providing redispatch priced at marginal cost is a fourth mechanism. LMP does not dictate which of these four methods is the more efficient or desirable approach. What LMP does provide is a common, transparent yardstick against which to measure the value of each of these investment choices. LMP will help investors and regulators determine whether transmission upgrades are both economically justified and more economically attractive (or otherwise preferred) relative to other options.

In addition, the award of incremental FTRs to those who fund transmission investments can be an additional incentive for those considering investments in transmission upgrades. As a result, at least some transmission investments could become market-driven and could even be undertaken (or at least funded) by merchant transmission developers or other Market Participants affected by LMP locational differences. Other LMP-based markets, such as PJM, appear to be seeing market-driven investments in new transmission in response to the values made transparent by LMP-based price signals. However, an essential component of these incentives is a set of rules for allocating FTRs for the incremental capacity created by any transmission upgrade. Under the Tariff, the Midwest ISO will issue FTRs to all Market Participants that fund Network Upgrades and elect not to receive credits under Attachment R.

Q. IN WHAT WAYS WILL THE MIDWEST ISO-COORDINATED MARKETS ENHANCE REGIONAL TRADING?

A. The Midwest ISO-coordinated markets will enhance regional trading in several ways: (1) the Midwest ISO real-time balancing market will support bilateral contracting and trading; (2) the Real-Time and Day-Ahead Energy Markets will provide additional mechanisms for generators to sell uncontracted power and for loads to cover uncontracted demand; (3) the use of FTRs will provide price certainty to transactions in the face of congestion and curtailment uncertainty; and (4) the use of LMP will reveal economic opportunities for commercially beneficial trades. In addition, the elimination of pancaked transmission rates within the Midwest ISO Region will lower barriers to efficient inter-regional trading.

Q. PLEASE EXPLAIN HOW THE MIDWEST ISO REAL-TIME BALANCING MARKET WILL SUPPORT BILATERAL CONTRACTING AND TRADING.

A. Parties that engage in bilateral trading will be free to use the Midwest ISO spot markets to any degree they choose to supplement and/or backstop their transactions. Generation suppliers can use the Midwest ISO Day-Ahead and Real-Time Markets to supplement their generation or replace it when the LMPs are either cheaper than their own operating costs or their own units experience an outage. Load Serving Entities ("LSEs") can supplement their contracts with purchases from the Midwest ISO Day-Ahead and Real-Time Markets, and use the real-time balancing market to purchase or sell any imbalances between their contract amounts and the amounts actually supplied or consumed. Open access to the Midwest ISO spot markets will thus relieve LSEs and their suppliers of any requirement to maintain balanced schedules or to engage in expensive load following on their own (although parties will be free to match their supplies and obligations as close as they want). With imbalance energy priced at market-clearing LMPs, parties will no longer be faced with the imbalance penalty charges they sometimes face today.

In addition, the transparent spot prices from the Midwest ISO markets will provide a useful reference for forward contracting and futures markets that enhance liquid contract trading. In general, forward contract prices will tend to reflect the market's expectations of future spot prices.

Q. PLEASE EXPLAIN HOW THE MIDWEST ISO MARKETS PROVIDE ADDITIONAL OPTIONS FOR UNCONTRACTED GENERATION AND UNCONTRACTED DEMAND.

A. Generators whose capacity is not fully committed to contracts will be free to offer any uncommitted capacity to the Midwest ISO for dispatch and operating reserves, allowing them to receive additional revenues and contributions to fixed costs to enhance their profitability and encourage adequate investment levels. Dispatched energy from these generators will receive LMP energy prices and any capacity held for operating reserves will receive the market clearing price for the type of reserves it provides. The sales can be made into the Midwest ISO Day-Ahead and/or Real-Time Markets. When generators are scheduled or dispatched to provide energy in the Day-Ahead Energy Markets, they receive day-ahead LMP prices for the scheduled amounts; any deviations in real time from the day-ahead schedules will be settled at the Real-Time LMPs.

Similarly, LSEs whose load obligations are not fully covered by contracts or the LSE's own resources will be free to purchase any remaining requirements from the Midwest ISO Day-Ahead Energy Market and/or Real-Time Markets. Any purchases in the Day-Ahead Energy Market will be settled at the Day-Ahead LMPs, and any deviations from the Day-Ahead schedules will be settled at the Real-Time LMPs.

Q. HOW WILL THE USE OF FTRS INCREASE THE CERTAINTY OF TRANSMISSION COSTS?

A. Generators and LSEs will be able to acquire FTRs through the Midwest ISO allocation process and through secondary trades with other parties. When the FTRs match the quantities and points of injection and withdrawal of a party's expected transactions, the FTRs will provide hedges against the congestion portion of the usage charges assessed to those transactions in the Midwest ISO markets. This effectively hedges the party against congestion charges and eliminates the risk of uncertain congestion costs.

Even if a party cannot acquire FTRs that exactly match its transactions, the party may still be able to acquire an acceptable hedge by acquiring a portfolio of FTRs that have a similar or greater settlement value as those matching the transaction. Because FTRs are financial instruments that entitle the holder to a set of dollars in the Day-Ahead Energy Market settlements, the actual FTRs owned do not have to match the party's actual schedules.

Q. HOW WILL THE USE OF LMP REVEAL OPPORTUNITIES FOR BENEFICIAL TRANSACTIONS?

A. Day-Ahead LMPs will be calculated for each hour of the next day and posted on the Midwest ISO website. Similarly, Real-Time LMPs will be calculated for each five-minute dispatch interval and posted on the Midwest ISO website. Market Participants will thus have a transparent set of day-ahead and real-time prices from which to determine the value of trades between any two locations on the grid (or between specific locations and aggregate LMP trading hubs).

Q. HAVE THE MIDWEST ISO MARKET MECHANISMS BEEN DESIGNED TO SUPPORT RETAIL COMPETITION IN THOSE STATES THAT PERMIT RETAIL CHOICE?

A. Yes. All of the features described above will make it easier for competitive retailers to meet their load-serving obligations to retail customers. Competitive suppliers will have full access to the Midwest ISO-coordinated markets for augmenting or backstopping their supply contracts. LSEs will have full access to these markets for augmenting or backstopping their load obligations. LSEs will also be eligible to receive an allocation of FTRs to allow them to hedge the uncertainty of congestion/redispatch costs.

Q. WILL THE MIDWEST ISO MARKET MECHANISMS ALSO SUPPORT LOAD-SERVING ENTITIES WITH DEFAULT SUPPLY OR STANDARD OFFER SERVICE OBLIGATIONS?

A. Yes. All of the mechanisms described above will also be available to those entities with default supply and standard offer service obligations. In particular, access to the Midwest ISO markets will reduce the risks these LSEs face from uncertain load obligations.

Because state retail choice rules usually allow loads to "move" to and from default supply or Standard Offer Service ("SOS") and competitive supply options, the existence of an open spot market provides a means for the LSE to lay off extra supplies or purchase extra supplies, as load obligations change. Again, these LSEs will be eligible for FTR allocations.

Q. WILL THE MIDWEST ISO'S MARKET MECHANISMS UNDERMINE THE ABILITY OF STATES AND/OR UTILITIES TO SERVE THEIR OWN CUSTOMERS AT LOWEST COST?

A. No. Just the opposite. The Midwest ISO's market mechanisms will actually enhance the ability of states and local utilities to serve their customers at the lowest costs, consistent with reliable operations. To begin with, by coordinating a regional economic dispatch Midwest ISO will be able to arrange a more efficient (*i.e.*, lower cost) dispatch for the region as a whole than can be achieved by the individual dispatches of the separate control areas. This more efficient regional dispatch can then serve loads that are relying on the regional dispatch at the lowest cost, given the dispatch offers and bids.

Areas currently served by low-cost resources will be able to continue to serve local loads at low cost, but any surplus low-cost resources can be offered to the Midwest ISO regional dispatch and thus help to lower dispatch costs for other areas within Midwest ISO yet return revenues for the entities owning the surplus low-cost resources. To the extent that an area relies on imports to serve local loads, the Midwest ISO's regional markets will facilitate that area's ability to be serve customers at lowest cost, either through purchases from the Midwest ISO-coordinated Day-Ahead Energy Market and real-time spot markets or through efficient scheduling of bilateral transactions between suppliers and load-serving entities. The Midwest ISO's LMP-based markets will then support these transactions with effective and efficiently priced redispatch, and with open access to the Midwest ISO spot markets to cover uncontracted amounts and imbalances in real time.

Q. HOW CAN UTILITIES IN LOW-COST REGIONS CONTINUE TO SERVE THEIR CUSTOMERS AT LOW COSTS, WHEN THE MIDWEST ISO MARKETS ARE REGIONAL?

A. The Midwest ISO OATT does not require any party to rely on the Midwest ISO spot markets to purchase any or all of their energy requirements or sell any or all of their output. Any party may arrange and schedule bilateral contracts between suppliers and LSEs, with the price for power defined by the contract, not by the Midwest ISO spot prices. Similarly, utilities and other regulated LSEs, such as default suppliers, are free to self schedule their own or contracted resources to meet their own load obligations, with the prices paid by default customers defined by contracts, by the LSEs/utilities and/or by state regulators using their authority over retail rates. Only the amounts actually purchased from the Midwest ISO spot markets would be priced at the Midwest ISO spot market-clearing prices. The Midwest ISO market mechanisms do not alter this fundamental allocation of retail rate-making authority.

IV. RESOLUTION OF KEY MARKET ISSUES

Q. HAS THE MIDWEST ISO PREVIOUSLY MADE AN ENERGY MARKETS FILING?

A. Yes. On July 25, 2003, the Midwest ISO submitted an energy markets filing in Docket No. ER03-1118-000. This filing was withdrawn by the Midwest on October 17, 2003 in response to concerns from Midwest ISO stakeholders, including the lack of clarity on certain key market elements.

Q. WHEN THE MIDWEST ISO FILED AN ENERGY MARKETS TARIFF ON JULY 25, 2003, WERE THERE ANY MARKET ISSUES THAT REQUIRED ADDITIONAL EXPLANATION?

A. Yes. The Commission recognized in an October 28, 2003 order in Docket No. ER03-1118-000, and the stakeholders raised in various discussions and filings, the fact that ten (10) major market issues required additional explanation. I will discuss the following key market issues in greater detail below: (1) System Supply Resource Program; (2) Treatment of Losses; (3) Resource Adequacy Requirements; (4) Emergency Energy Purchases Procedures; (5) Uninstructed Deviation Penalties; (6) Development of a Demand Response Program; (7) Unit Commitment Procedures; (8) Data Confidentiality Issues; (9) Analysis of the existing Grandfathered Agreements in Attachment P; and (10) Advance effective dates for certain portions of the Tariff.

1. SYSTEM SUPPLY RESOURCE PROGRAM

Q. WHY IS THE PROPOSED SSR PROGRAM IMPORTANT TO THE MIDWEST ISO'S ENERGY MARKETS?

A. One of the Midwest ISO's core functions is to provide reliable grid operation. The SSR program addresses circumstances where a Market Participant is planning to retire, place into extended reserve shutdown or disconnect a generation facility based on an economic evaluation. If the Midwest ISO determines that the unavailability of such resources may detrimentally impact grid reliability, the Midwest ISO requires appropriate operational tools to maintain the availability of such units. Accordingly, the SSR program provides the Midwest ISO with sufficient operational tools to ensure the reliable functioning of the transmission grid.

Q. PLEASE DESCRIBE SSR UNITS?

A. SSR Units are those resources that have been determined by the Midwest ISO to be vital to the continued reliability of the grid. A Market Participant can retire, place into extended reserve shutdown, or disconnect a generation resource only after executing an affidavit verifying that it intends to do so based on economic considerations, at least twenty-six (26) weeks before taking such action. Thereafter, the Midwest ISO will conduct an analysis to determine whether reliability of the transmission grid would be adversely impacted if the subject unit was unavailable for an extended period of time beyond typical forced and maintenance outages. Such resources will only be designated as SSR Units after no other alternatives can be found that are more economic to mitigate reliability issues. If the Midwest ISO determines that the unavailability of a particular unit could be detrimental to the reliability of the grid, such units will be required to enter into an agreement with the Midwest ISO which will require the facility to remain available for dispatch by the Midwest ISO.

Q. PLEASE EXPLAIN HOW SSR UNITS ARE DIFFERENT FROM RELIABILITY MUST RUN (“RMR”) UNITS?

A. RMR units typically are generating resources that are needed to support some aspect of system reliability, but also have the potential to exercise market power due to their location. RMR units are facilities that may be needed by the grid operator during some period of time, but whose owners have not indicated any intention to retire, place into extended reserve shutdown, or disconnect the facility. The Midwest ISO is addressing RMR issues in Module D of the Tariff, the Market Monitoring and Mitigation procedures and Module E, Resource Adequacy. By contrast, SSR Units are facilities that will be retired, placed into extended reserve shutdown, or disconnected due to economic circumstances, but which the Midwest ISO determines are required for system reliability.

Q. WHY IS THE MIDWEST ISO REQUIRING AN AFFIDAVIT AS A PART OF THE SSR PROGRAM WHERE A MARKET PARTICIPANT DESIRES TO RETIRE, PLACE INTO EXTENDED RESERVE SHUT DOWN, OR DISCONNECT A UNIT?

A. The Midwest ISO believes that an affidavit will ensure that the Market Participant has decided to retire, place into extended reserve shutdown, or disconnect the unit based solely on legitimate and verifiable economic considerations. The Midwest ISO believes that the use of an affidavit will prevent possible market manipulation by a Market Participant that might desire to increase market prices by reducing available resources. The affidavit will also prevent Market Participants from simply seeking protected status as an SSR Unit when the market demonstrates depressed prices. An affidavit is a robust tool for ensuring that Market Participants act in good faith.

Q. WHICH ENTITY WILL BE PRIMARILY RESPONSIBLE FOR IMPLEMENTING THE SSR PROGRAM?

A. The Midwest ISO will be solely responsible for implementing and executing the SSR program. The Midwest ISO believes that the need for certain units to remain available is best accomplished on a system-wide basis. Moreover, the Midwest ISO is better prepared to guarantee the uniform treatment of SSR Units throughout the Transmission Provider Region.

Q. HAVE OTHER U.S. DEREGULATED ENERGY MARKETS DEVELOPED SSR PROGRAMS OR SIMILAR INITIATIVES?

A. Yes. ERCOT and ISO New England have implemented programs that consider many of the same issues presented in the Midwest ISO's SSR program.

Q. PLEASE EXPLAIN.

A. The ERCOT RMR program acts much like the Midwest ISO SSR Program because it also is designed to compensate units that have declared their intention to retire, be placed in extended reserve shut down, or be disconnected for economic reasons. The ERCOT program relies on agreements between ERCOT and the subject RMR units to ensure that associated costs are adequately compensated. By contrast, ISO New England has established a program to compensate RMR units for certain going forward maintenance costs and by implementing a market-based bid mechanism for high-cost, seldom used units located in designated congested areas. Although the ISO New England program must consider market power issues either not present in the Midwest ISO or addressed in Module D, the implementation of the ISO New England program nonetheless provides the Midwest ISO with important guidance.

Q. TO WHAT DEGREE DOES THE MIDWEST ISO SSR PROGRAM INCORPORATE ELEMENTS OF THE ERCOT AND ISO-NEW ENGLAND PROGRAMS?

A. Consistent with programs in ERCOT and ISO-New England, the Midwest ISO proposes that cost compensation be provided to SSR Units on a unit-by-unit basis to account for certain fixed costs associated with SSR status. The Midwest ISO believes that SSR Unit agreements will serve as the most reliable and financially stable mechanism for guaranteeing an appropriate level of cost recovery for SSR Units. Moreover, consistent with Commission precedent, the Midwest ISO will allow Market Participants with SRR Units to submit market-based offers and set LMP for the portion of their SSR Unit not committed under terms of an SSR agreement.

Q. WHAT COSTS WILL SSR UNITS BE ABLE TO RECOVER?

A. The Midwest ISO will allow for the recovery of certain going forward costs on a unit-by-unit basis. Eligible costs are costs that would be incurred by the SSR Unit owner to provide service above the costs the SSR Unit would have incurred anyway had it been retired, placed into extended reserve shutdown, or disconnected. The Midwest ISO will evaluate the following factors in negotiating the SSR Unit compensation: (i) fixed operating and maintenance costs; (ii) applicable state, federal or property taxes; and (iii) costs of repairs or upgrades needed to meet applicable environmental regulations or local operating permit requirements. Any compensation to the SSR Unit will be reduced by expected debits under Schedule 2 of this Tariff, expected payments under resource adequacy programs, and expected revenue from Energy Market transactions.

Q. WHAT ABOUT SYNCRONIZED CONDENSER UNITS?

A. Synchronized condenser units will also be eligible for SSR Unit status and the associated compensation. Compensation mechanisms may vary slightly for synchronized condenser units due to their unique operating characteristics and functions. Cost compensation for synchronized condenser units will be recovered through Schedule 2 of the Tariff.

Q. ULTIMATELY, WHO WILL BE RESPONSIBLE FOR COSTS ASSOCIATED WITH THE SSR PROGRAM?

A. The Midwest ISO proposes that SSR cost responsibility be allocated on a pro rata basis to the Market Participants serving load within the specifically affected control areas. This methodology represents a hybrid approach to cost causation which makes specific control areas responsible for local reliability issues. The Midwest ISO believes that assigning the costs on a local or sub-regional basis provide incentives for the affected control area to take measures to improve reliability. The Midwest ISO's hybrid proposal avoids subjecting Market Participants outside the immediate affected control area from incurring costs that the outside Market Participant is unable to alleviate on their own accord.

Q. WHAT IS THE ANTICIPATED USE OF SSR UNITS IN THE MARKET?

A. The Midwest ISO anticipates designating a resource as an SSR Unit primarily for reactive power purposes, but may also designate a facility as an SSR Unit for real power needs on a limited basis. The Midwest ISO proposes to limit the use of SSR agreements in the market given other available tools. The Midwest ISO believes that while the SSR program serves as a basic reliability tool that should be available as necessary, the use of the SSR program is designed to be a limited safety net to ensure system reliability. The excessive use of SSR agreements is contrary to established market principles. To avoid such excessive use of the SSR program, the Midwest ISO will annually re-evaluate SSR Units to assess alternatives to mitigate reliability issues and for continuing need.

2. TREATMENT OF LOSSES

Q. WILL THE MIDWEST ISO UTILIZE AN AVERAGE LOSS OR A MARGINAL LOSS METHODOLOGY TO ACCOUNT FOR TRANSMISSION RELATED LOSSES?

A. The calculation of the LMP will include the effective marginal losses at every node. All Market Participants making purchases through the Energy market will therefore be subject to marginal losses through the LMP methodology. Similarly, Bilateral Transactions Schedules will be subject to the marginal losses component of the LMP assessed through the transmission usage charge at the relevant injection and withdrawal points.

Q. WHY HAS THE MIDWEST ISO CHOSEN TO ADOPT A MARGINAL LOSS METHODOLOGY?

A. The primary reason the Midwest ISO has decided to include the effect of marginal losses in the calculation of locational marginal prices is due to the geographic scope of our Region and the needs of the Midwest ISO unit dispatchers. Generation that travels a great distance to serve load may have different loss characteristics than local generation and the mechanism used by the dispatcher to manage real time power flows, (*i.e.,* locational marginal prices), must, in order to be effective, reflect the actual effects of generation location. By including the effect of marginal losses, the LMP calculation sends enhanced economic signals to Market Participants regarding the cost of using the transmission system, which must reflect the true cost of transmission power losses and energy flows on the system. This allows parties to determine whether it is economic to continue to use the system. The use of the marginal losses methodology, however, necessarily results in the creation of a revenue surplus (relative to the use of an average loss methodology).

Q. WHAT WILL THE MIDWEST ISO DO WITH THE REVENUE SURPLUS COLLECTED?

A. In order to balance the Energy Market accounts, the Midwest ISO will return the surplus to the Market Participants.

Q. HOW AND TO WHOM WILL THE MIDWEST ISO RETURN THE SURPLUS LOSSES REVENIE COLLECTED?

A. Consistent with directives from FERC, the Midwest ISO and its stakeholders strove to find a methodology that would not "undo" the economic incentives of the marginal losses methodology. Therefore, it was soon apparent that the Midwest ISO could not return losses revenue directly to those paying losses at a transactional level. The Midwest ISO faces an additional challenge in that its Region spreads across a vast geographic area, over which actual transmission losses vary significantly. Therefore, stakeholders objected to a redistribution methodology that would ignore these regional differences in actual transmission losses and would result in cross subsidization across regions. Through the stakeholder process, extensive discussions were held to determine an appropriate methodology for returning the revenue loss surplus to Market Participants in a manner that is both efficient and equitable. The Midwest ISO adopted the proposed methodology that redistributes the excess revenue on a "regional" basis and attempts to minimize subsidization across the regions. The proposed redistribution methodology will first allocate the losses revenue surplus to sub-regions of the Midwest ISO Region based on the actual losses incurred at the sub-regional level on an hourly basis. These sub-regions are referred to as "Losses Pools." Subsequently the Midwest ISO will distribute the Losses Pool's share to Market Participants in the Losses Pool on a pro-rata basis, by the MWh served by each Market Participant through the Energy Markets or through Bilateral Transaction Schedules. Market Participants serving Load under such Grandfathered Agreements will be credited back the full amount of the difference between marginal losses and average losses for such transactions. Therefore, the Losses Pools will not include surplus losses revenue for transactions pursuant to Grandfathered Agreements and the Losses Pools amounts will not be allocated to any Load served under Grandfathered Agreements.

Q. HOW WILL THE MIDWEST ISO DETERMINE THE LOSS POOLS?

A. The Losses Pools will consist of aggregations of Control Areas, in which the Midwest ISO has identified similar actual losses. The Losses Pools can be modified over time as transmission losses change. Losses Pools are defined on the basis of actual hourly transmission losses and must be large enough to include multiple load serving entities, while small enough to capture differences between areas.

3. RESOURCE ADEQUACY PROPOSAL

Q. WHY IS RESOURCE ADEQUACY RELATED TO THE DEVELOPMENT OF THE MIDWEST ISO'S ENERGY MARKETS?

A. Market economics and reliability are inextricably intertwined. Markets that are otherwise competitive and robust will nevertheless fail if they do not provide sufficient incentives to ensure reliability. One of the keys to reliable grid operations is to ensure that Market Participants provide and have access to adequate generation resources.

One of the challenges that the Midwest ISO and its stakeholders face is ensuring resource adequacy during the transition to our new market structure. While changes will be made to the resource adequacy requirements at a future time (and the Midwest ISO commits to working with its shareholders to evaluate all possible changes), a resource adequacy program must be adopted as an integral component of the Midwest ISO market, even if the specific plan is applicable only on an interim basis.

Q. HAS THE MIDWEST ISO DISCUSSED THE TOPIC OF RESOURCE ADEQUACY WITH ITS STAKEHOLDERS?

A. Yes, the Midwest ISO has discussed resource adequacy extensively with our stakeholders. For example, a presentation was made by the Midwest ISO at the Market Subcommittee on November 20, 2003 and was further discussed at the subcommittee meeting held on December 3, 2003. After this second meeting, the Midwest ISO drafted a white paper on resource adequacy that enumerated further details regarding the Midwest ISO's direction on this issue. This white paper was distributed to subcommittee members on December 18, 2003 with an updated version presented on January 6, 2004. In addition, the Midwest ISO has conducted extensive discussions regarding resource adequacy with the Supply Adequacy Working Group ("SAWG"), a committee of stakeholders that was formally chartered in early February 2004. The SAWG met on February 9, February 17, March 1, and March 15, 2004 to discuss a work plan for developing a finalized resource adequacy proposal. The Supply Adequacy Working

Group's ("SAWG") work plan and timetable is attached to the subject Transmittal Letter as Exhibits MISO-2 and MISO-3, respectively.

In addition to the SAWG, the Organization of MISO States has created a Resource Adequacy Working Group ("RAWG") to develop proposals by its membership to ensure resource adequacy within the Midwest ISO. On March 26, 2004, RAWG released a set of "Resource Adequacy and Capacity Markets Principles" to guide its future discussions regarding this subject. A copy of this document is attached to the subject Transmittal Letter as Exhibit MISO-1. Both SAWG and RAWG have held joint meetings and have begun to develop their proposals in tandem. Midwest ISO personnel have been actively involved in these meetings.

Q. HAVE THE STAKEHOLDERS REACHED ANY CONSENSUS REGARDING THE DEVELOPMENT OF A RESOURCE ADEQUACY PROGRAM?

A. A large majority of stakeholders appear to agree that adequate reserves must be maintained to ensure reasonably reliable operation of the grid. Unfortunately, stakeholders are divided regarding the details of a comprehensive resource adequacy program. At the January 6, 2004 meeting of the Markets Subcommittee, the Midwest ISO submitted an interim resource adequacy approach for consideration by stakeholder representatives. The members of the subcommittee voted on a motion at the January 6, 2004 meeting advising the Midwest ISO that "Stakeholders do not support the interim Resource Adequacy approach presented by the Midwest ISO." However, no other proposal to address resource adequacy was approved by the subcommittee. In addition, the SAWG committee charter provided that SAWG could propose to the Midwest ISO by March 17, 2004 either a recommendation establishing resource adequacy guidelines or a work plan to develop such guidelines. The SAWG has provided a work plan, but did not propose a resolution of the issue. Hence, the Midwest ISO comes before the Commission today without any stakeholder consensus on this very important issue.

Q. WHAT ARE THE KEY STAKEHOLDER CONCERNS REGARDING THE MIDWEST ISO'S PROPOSAL?

A. One key issue raised by stakeholders is the lack of clear, definitive resource adequacy standards in the Regional Reliability Organizations ("RROs") within which the Midwest ISO operates. For example, ECAR's requirements have been singled out by some stakeholders as being vague and unworkable. In addition, there have been questions regarding the interaction between state regulatory resource adequacy requirements and potentially contrary RRO requirements. A number of other disputes exist among stakeholders regarding this issue as well. I am certain that stakeholders will voice their views in reply comments and in other pleadings before the Commission in this proceeding. The Midwest ISO will be reviewing these comments closely and hopes to continue engaging stakeholders on this issue.

Q. HAS THE MIDWEST ISO DEVELOPED A RESOURCE ADEQUACY PROPOSAL?

A. Yes, it has. Although the Midwest ISO would prefer stakeholder consensus regarding resource adequacy, it is the Midwest ISO's responsibility to propose a resource adequacy program as an interim measure until such time as a more formalized plan may be submitted for Commission approval.

Q. WHAT ARE THE KEY ELEMENTS OF THIS PROPOSAL?

A. The proposal is provided in proposed Module E of the Midwest ISO's Tariff. Module E provides, as a general matter, that: (1) Market Participants must continue to comply with all applicable RRO requirements for load served in the Midwest ISO region; (2) Market Participants must also comply with all state authority regarding resource adequacy or reliability; (3) the Midwest ISO will monitor resource adequacy compliance by Market Participants, including determinations as to whether a resource qualifies as satisfying RRO and state reliability requirements; (4) if the Midwest ISO determines that no resource adequacy standard exists within a state, it will require an annual reserve margin of 12% to load served in that state; and (5) all resources identified by Market Participants as available to meet resource adequacy requirements must comply with the requirements for specification as Designated Network Resources ("DNRs").

Q. IF THE RESOURCE ADEQUACY REQUIREMENTS OF A STATE AUTHORITY AND AN RRO DIFFER, WITH WHICH REQUIREMENTS SHOULD A MARKET PARTICIPANT COMPLY?

A. If it is technically possible to comply with both applicable state and RRO resource adequacy requirements, then Market Participants must comply with both sets of requirements. The Midwest ISO will work with both state authorities and RROs within the Midwest ISO service region to ensure that the requirements of RROs and states do not conflict. However, if the Midwest ISO determines that the requirements of a state and an applicable RRO are irreconcilable, the Midwest ISO will determine standards that comply fully with the obligations imposed by the state while complying with such portion of the RRO's requirements as is feasible. As a practical matter, the Midwest ISO believes that the vast majority of obligations imposed by state authorities and RROs will not conflict and, in the unusual case where such requirements do conflict, the Midwest ISO, the applicable state authority, and the RRO will be able to resolve any differences quickly. The Midwest ISO fully expects to play an active and helpful role with both RROs and state authorities to ensure a seamless implementation of this proposal.

Q. WHY DID THE MIDWEST ISO DETERMINE THAT AN ANNUAL RESERVE MARGIN REQUIREMENT OF 12% WAS APPROPRIATE IN AREAS WHERE NO RESOURCE ADEQUACY REQUIREMENT WAS IMPOSED BY AN RRO OR A STATE AUTHORITY?

A. The Midwest ISO has determined that a resource adequacy requirement must exist for all loads in its service region. Some areas of the Midwest ISO service region do not fall under either state or RRO resource adequacy requirements. It would be imprudent to provide service to customers in these areas with no assurance that a reasonable resource adequacy requirement was in place. The 12% annual reserve margin requirement is based upon: (1) the Midwest ISO's independent judgment that such a requirement sufficiently enhances reliability while not being so onerous as to negatively impact the market; and (2) such a requirement is comparable to reserve requirements imposed by RROs and state authorities in the Midwestern United States.

Q. HOW WOULD YOU ASSESS THE PRESENT STATE OF GENERATION RESOURCES WITHIN THE MIDWEST ISO?

A. I would say that the Region has adequate generation resources. The Region can reasonably expect to retain adequate generation resources under the proposed plan at least for the next year or more after the beginning of the energy market.

Q. COULD YOU PLEASE EXPLAIN THE REQUIREMENT THAT RESOURCES RELIED UPON TO MEET RESOURCE ADEQUACY REQUIREMENTS MUST COMPLY WITH THE REQUIREMENTS FOR SPECIFICATION AS A DNR.

A. Certainly. It is the Midwest ISO's belief that resources relied upon to meet minimum resource adequacy requirements in the Midwest ISO region must indeed be available to meet load in the Midwest ISO. To demonstrate this availability, resources must meet the requirements for designation as a DNR, including ownership or similar contractual rights to the resource. In addition, the resource must be able to transmit energy to those areas for which it is to be relied upon for reliability purposes. Thus, a System Impact Study validating a dispatch to the area will be performed for the resource, if no study has already been completed.

Q. WHAT ARE "ALTERNATIVE CAPACITY RESOURCES?"

A. Alternative Capacity Resources are resources that fail to meet the criteria established to be a DNR, but that may nonetheless be used to satisfy the resource adequacy requirements of RROs and state authorities. The Midwest ISO has determined that Alternative Capacity Resources are: (1) resources serving interruptible load subject to a demand reduction for economic or emergency reasons; and (2) behind the meter generation owned by Market Participants. These resources may not necessarily be able to be designated as DNRs, but the Midwest ISO nevertheless believes that they may be utilized to meet some RRO and state authority resource adequacy requirements.

Q. WHAT IS THE "MUST OFFER" REQUIREMENT FOR DNRS AND WHY HAS THE MIDWEST ISO INCLUDED SUCH A PROVISION IN MODULE E?

A. Under Module E, 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. The Midwest ISO believes that such a requirement is necessary to ensure that DNRs are available to serve load in times where reliability may be threatened.

Q. DOES THE MIDWEST ISO EXPECT FULL COMPLIANCE WITH THE DNR REQUIREMENTS OF MODULE E AS OF THE FIRST DAY OF OPERATION OF THE MARKET?

A. The Midwest ISO expects all Market Participants to make all reasonable good faith efforts to comply with all requirements of the Midwest ISO Tariff, including the DNR requirements, by the first day of operation of the market. However, the Midwest ISO is not insensitive to the time that may be required for some Market Participants to structure their dealings so as to comply with the DNR requirements. Thus, Module E provides that the Midwest ISO may provide for a grace period to comply with the DNR requirements. If any such grace period is adopted, the Midwest ISO will notify all Market Participants. Any grace period will exist for the minimum time required to permit good faith compliance with the DNR requirements.

Q. IS THERE ANY TENSION BETWEEN THE ESTABLISHMENT OF AN OFFER CAP AND THE NEED TO ENSURE ADEQUATE GENERATING RESOURCES?

A. Absolutely. By their nature, offer caps have a tendency to discourage construction of additional generation resources. Potential new generation will have profits capped by market regulators and, thus, there is a decreased incentive to engage in costly construction. One of the goals of a resource adequacy program must be to balance the need to encourage new generation with the customer protections afforded by an offer cap.

Q. DOES THE MIDWEST ISO PROPOSE AN OFFER CAP FOR ITS MARKET?

A. Yes. After much consideration, the Midwest ISO is proposing a $1,000 MWh offer cap for electricity.

Q. FOR WHAT REASONS DID THE MIDWEST ISO SELECT A $1,000 MWH OFFER CAP?

A. A $1,000 MWh offer cap was selected for two primary reasons. First, other RTOs to the east of the Midwest ISO have selected a $1,000 offer cap. By conforming the Midwest ISO's offer cap to the offer caps in these nearby regions we have eliminated any bias or seams issues with regards to offering behavior. Secondly, we determined that implementing a $1,000 offer cap during the interim period while a long term resource adequacy proposal was being developed was sufficient to provide price stability without discouraging generation in the short term.

Q. IN YOUR PRIOR TESTIMONY, YOU PROPOSED AN OFFER CAP OF $5,000 MWH. WHY DO YOU NOW BELIEVE THAT A $1,000 MWH OFFER CAP IS SUPERIOR?

A. The Midwest ISO has proposed this lower offer cap in an attempt to alleviate fears by some Market Participants and State regulators that prices during the formative stages of the market may spike to unacceptable levels. Once Market Participants have become acclimated to the functioning market and changes to the Midwest ISO's resource adequacy requirements are made, the Midwest ISO may request authority to modify the

$1,000 MWh offer cap or provide other mechanisms to provide increased incentives for generation.

Q. YOU MENTION ABOVE THAT A KEY GOAL OF THE MIDWEST ISO IS TO BALANCE THE APPLICABLE OFFER CAP WITH ENCOURAGEMENT OF GENERATION RESOURCE ADEQUACY. IS THAT BALANCE ACHIEVED BY THE MIDWEST ISO'S PRESENT PROPOSAL?

A. Yes, for an interim period such a balance is successfully struck. While RTOs to the Midwest ISO's east have adopted a $1,000 MWh offer cap, they have chosen to balance the discouraging effect that such a cap has on the location of new generation with incentives to new generation, such as installed capacity payments. The Midwest ISO's stakeholders have not yet approved any such incentive mechanism. However, it is the Midwest ISO's independent opinion that incentive mechanisms (whether or not similar to those adopted by other RTOs) are necessary to encourage robust generation construction *in the long-term*. Generation, however, is neither constructed nor removed overnight. For an interim period of time (for example, for a year), it is perfectly acceptable to have a $1,000 offer cap while working towards a more formalized incentive mechanism.

Q. ON A GOING FORWARD BASIS, WILL THE MIDWEST ISO INVOLVE THE OMS IN RESOURCE ADEQUACY DISCUSSIONS?

A. Absolutely. As I mention above, the Midwest ISO is fully aware that resource adequacy mechanisms represent an ongoing, controversial issue between its stakeholders. Indeed, the Midwest ISO submits the present resource adequacy proposal with the expectation that stakeholder discussions will continue with the goal of reaching a consensus resource adequacy program to submit to the Commission at some point in the near future.

OMS will play a critical role in the formulation of a revised resource adequacy policy during the first year of market operation. The Midwest ISO has worked directly with the Organization of MISO States' RAWG as well as with OMS representatives in more inclusive stakeholder settings. While the OMS RAWG very recently provided a list of general principles to guide the formation of a permanent resource adequacy program, to date, OMS has not proposed a specific resource adequacy plan to the Midwest ISO. If OMS derives such a plan, the Midwest ISO will give it substantial consideration and will work with OMS to resolve any issues that may arise. However, the obligation to ensure adequate resources within the Midwest ISO area of operations is, ultimately, the Midwest ISO's duty. Any proposal will be independently reviewed by the Midwest ISO.

Q. WILL THE MIDWEST ISO CONTINUE TO WORK WITH ITS STAKEHOLDERS TO RESOLVE THESE ISSUES?

A. Yes. As I mentioned above, a new working group, the SAWG, has been created with the express purpose of evaluating resource adequacy issues and making concrete proposals to ensure such adequacy within the Midwest ISO Region for the indefinite future. This group approved its charter on February 3, 2004 and has begun working on the thorny issues herein discussed. Recently, SAWG released the work plan, under which it will create a finalized resource adequacy proposal by July 1, 2005. It is the Midwest ISO's hope and expectation that the SAWG will be able to adhere to this timeline.

In addition, the OMS RAWG is continuing its work on a resource adequacy proposal consistent with the recently-released principles. While both SAWG and RAWG are stakeholder bodies, they have been in close communication and have held coordinated meetings. It is the Midwest ISO's hope that both committees will submit a joint consensus plan for the Midwest ISO's consideration. The Midwest ISO will assist the SAWG membership and OMS RAWG committees in their endeavors.

4. EMERGENCY ENERGY PURCHASES

Q. WHY IS IT IMPORTANT FOR THE MIDWEST ISO TO HAVE THE ABILITY TO ACQUIRE EMERGENCY ENERGY?

A. One of the Midwest ISO's core functions is to provide reliable grid operation to ensure the continued success of robust and competitive energy markets. The Emergency Energy Purchase procedures provide a mechanism that allows the Midwest ISO to ensure the continued reliability of the system if there are insufficient energy resources available to meet the forecasted peak load, and are just one of several actions that may be taken to attempt to resolve a declared energy emergency.

Q. HOW WILL THE MIDWEST ISO DETERMINE WHEN EMERGENCY ENERGY PURCHASES ARE NECESSARY?

A. As part of the Real-Time Operational Process, the Midwest ISO will perform a rolling look-ahead dispatch study. If demand is expected to exceed committed capacity less minimum operating reserve, the Midwest ISO (acting pursuant to its responsibilities as the Reliability Authority) will issue a maximum generation warning message. Offers for the emergency range of each resource will be used to calculate the least-cost dispatch solution to clear the real-time energy market. The Midwest ISO will coordinate with Control Areas and Market Participants to locate any generation not committed, or any generation scheduled to go offline, so that they may be committed as quickly as possible.

Any other additional units will be committed, and non-firm exports of energy out of the Midwest ISO will be curtailed.

Q. IF THE ENERGY EMERGENCY IS NOT RESOLVED USING THE ABOVE PROCEDURES, WHAT FURTHER STEPS WILL THE MIDWEST ISO TAKE TO ENSURE THE RELIABILITY OF ITS GRID?

A. If, after taking the steps outline above, energy balance has not been achieved, the Midwest ISO will employ off-line generation that is designated as available only for maximum generation emergency conditions, and will clear the real-time energy market using Security Constrained Economic Dispatch ("SCED"). The Reliability Authority may take the following actions, as necessary to clear the real-time energy market: 1) require utility load conservation (reduced station power); 2) implement emergency energy purchase offer procedures; 3) implement voltage reduction measures, if prudent; 4) recall firm exports from network resources or the spot market; 5) dispatch non-economic interruptible load (economic load reduction not under Midwest ISO control taken when appropriate); 6) make Emergency Energy purchases; and 7) instruct use of Operating Reserves to serve energy requirements as needed. The above actions would generally be taken in the order presented, although circumstances may dictate a different sequence of actions. Such determinations will be made at the discretion of the Midwest ISO. When possible, the Midwest ISO will attempt to provide at least 60 minutes notice before emergency energy is required. The Midwest ISO will post a message to its website that: 1) emergency energy purchases are anticipated beginning at a specific time; and 2) offers for emergency energy are requested.

Q. HOW WILL EMERGENCY ENERGY PURCHASES BE SCHEDULED AND DELIVERED?

A. The Midwest ISO Business Practice Manuals will provide details on how offers for emergency energy purchases are to be submitted to the Midwest ISO. The Midwest ISO will accept offers on an economic basis--that is, lower cost offers will be accepted before higher cost offers, and similarly priced offers will be accepted based on when they are submitted to the Midwest ISO. The Midwest ISO will accept and schedule lower cost offers received after previously submitted purchases have been accepted and scheduled to the extent there is sufficient time prior to the scheduled start time. Emergency energy deliverability is the responsibility of the seller of such energy. Offers will be accepted from external sources, but firm transmission service may be required if, for example, an external Reliability Authority has issued a TLR. Emergency energy may be requested from neighboring control areas after all energy offered by Market Participants has been accepted, unless the Midwest ISO determines an immediate need that requires that the normal offer process be circumvented. The Midwest ISO will implement and curtail emergency energy purchase transactions with as much notice as possible to allow for a reliable transition into and out of emergency conditions. If the Midwest ISO makes operating reserve capacity available for dispatch to serve energy requirements during an energy emergency, the operating reserve capacity segments dispatched in merit are offered at $1,000/MWh and are eligible to set Ex Post Real-Time LMPs. The costs of emergency energy purchases will be recovered through the LMP market. To the extent that the real time LMP at the delivery point is less than the accepted emergency energy offer prices, additional costs incurred will be reimbursed to the seller through a revenue sufficiency guarantee.

Q. ARE THERE PROCEDURES THAT THE MIDWEST ISO MAY TAKE IF THE EMERGENCY ENERGY MEASURES DO NOT ALLOW THE MIDWEST ISO TO ACQUIRE SUFFICIENT CAPACITY TO MEET DEMAND?

A. Although we expect the Emergency Energy procedures to be sufficient to secure the reliability of the grid, if sufficient capacity is still not found and if demand is still expected to exceed committed capacity less minimum operating reserves after all the emergency energy purchase procedures have been implemented, the Midwest ISO will implement approved load shedding procedures as necessary to ensure the continued function and reliability of the system.

5. UNINSTRUCTED DEVIATION PENALTIES

Q. WHY ARE THE PROPOSED TARIFF PROVISIONS REGARDING UNINSTRUCTED DEVIATION PENALTIES NECESSARY?

A. In order to effectively operate its energy markets and manage congestion in the context of a multi-control area environment, the Midwest ISO needs to have a mechanism in place that discourages generators from deviating from their real-time dispatch schedules. The proposed uninstructed deviation penalties create a well-tailored solution that will discourage frequent and excess deviations from dispatch instructions in an equitable manner.

Q. HOW WILL THE TARIFF ACHIEVE THE GOAL OF DISCOURAGING DEVIATIONS FROM DISPATCH INSTRUCTIONS?

A. Appropriate penalties, developed with the input of stakeholders have been adopted, and will apply to generators that deliver energy at levels above or below their dispatch instructions for a given time frame.

Q. HOW MUCH WILL THE PENALTY FOR DEVIATION BE, AND HOW WILL IT BE CALCULATED?

A. Penalties will be assessed for deviations from Dispatch Instructions subject to a tolerance band of +/-10%. The tolerance band will be adjusted by adding the MW of regulation capacity being provided by the resource. The tolerance band is based on an hourly average deviation from the base point, including a minimum tolerance band of 5 MW and a maximum tolerance band of 25 MW. This approach provides sufficient flexibility to allow for deviations due to normal operations. The generator will be paid for total output in all cases, but at decreasing $/MWh levels for deviations outside the tolerance band. For under-generation, generators will pay a penalty of the product of 40% of the hourly Ex Post LMP calculated for the applicable Hour and the positive difference between the tolerance band lower limit and the actual injection at the node. For over-generation, generators will be paid only the product of 40% of the hourly Ex Post LMP for the applicable hour at that node, and the positive difference between the actual injection at the node and the tolerance band upper limit. Attached as Exhibit RRM-1 to this affidavit are examples of payment calculations for over generation and under generation deviations.

Q. WAS STAKEHOLDER INPUT CONSIDERED IN THE DEVELOPMENT OF THE UNINSTRUCTED DEVIATION PENALTIES?

A. Yes. In response to stakeholder requests, the one-tier tolerance band system was implemented instead of a two-tier tolerance band system that would have imposed stricter tolerances and graduated penalties depending on the amount of the deviation from the dispatch schedule.

6. DEMAND RESPONSE PROGRAM

Q. WHAT ARE DEMAND RESPONSE RESOURCES?

A. Demand Response Resources ("DRRs") are one of several mechanisms for demand participation in the Day-Ahead and Real-Time energy markets. A DRR is load within the Midwest ISO that can be withdrawn in response to dispatch instructions in real-time operation or in response to high LMPs in the Day-Ahead Energy Market. DRR offers are offers made in the Day-Ahead and Real-time Energy Markets, modeled similarly to generation resources, but represent reductions to load (negative injections).

Q. HOW DO DEMAND RESPONSE RESOURCES HELP TO DEVELOP EFFECTIVE MARKETS?

A. Reducing demand on the electricity grid has the same net effect as increasing generation output to meet demand. Allowing DRRs into the market provides an efficient method to reduce load by allowing Market Participants the opportunity to remove demand from the marketplace at market based rates, instead of increasing generation. DRRs can lower the LMP for all Market Participants, and alleviate congestion, which increases the reliability of the system.

Q. HOW WILL THE DRR CONCEPT FIT INTO THE OVERALL ENERGY MARKET?

A. DRRs will be allowed to submit an energy offer that consists of a monotonically increasing curve, of up to 10 price and quantity segments, or a piecewise linear curve of up to ten segments representing the price at which the DRR will voluntarily adjust its schedule. DRRs will be allowed to set the LMP based on their cleared offer curves, but will not be eligible to receive Revenue Sufficiency Guarantees to recover cost for start-up and operation at zero load. DRRs will not be subject to uninstructed deviation charges.

Q. ARE THERE ANY UNRESOLVED PROBLEMS ASSOCIATED WITH ALLOWING DRRS INTO THE ENERGY MARKET?

A. Yes. One unresolved issue associated with DRRs is how to measure compliance with dispatch instructions. Because the DRR typically represents only a portion of the total load at a load bus, it is in most cases impossible to distinguish between DRR failure to follow dispatch and other factors that may lead to load variation during the dispatch period. Stated differently, it is difficult to determine if DRRs are reducing their load due to other, independent factors, or in response to the DRR Offer.

Q. HOW WILL THIS ISSUE BE RESOLVED, AND WHAT SAFEGUARDS WILL THE MIDWEST ISO IMPLEMENT IN THE INTERIM?

A. This compliance issue may be resolved through metering, or in other cases through Midwest ISO Business Practice Rules. Until this issue is addressed through the stakeholder process and resolved with their input, it is appropriate to differentiate between treatment of DRRs and generation in two regards: Revenue Sufficiency Guarantees, and Uninstructed Deviations, neither of which will apply to DRRs initially.

Q. HOW DOES AN INDIVIDUAL DRR FUNCTION IN THE OVERALL MARKET?

A. Commercial nodes must be defined for both "unit" and "load" resources. Only the "negative" injection node (the supply resource) of the DRR need be defined as a DRR; the demand part of the model is defined as a demand. Telemetry and metering is required for both resources: the unit resource receives DRR response MW values; the load resource receives the sum of the observed load PLUS any DRR response. The key is that the net of these two values represents the observed load.

Q. HOW WILL DRRS SETTLE TRANSACTIONS?

A. In the Day-Ahead Market, a Load Commercial Node will settle at cleared load quantity plus cleared DRR Response quantity. DRR Response will settle like any other generation resource. Again, the key is that the net of these two values represents the settled load. The Market Participant is financially indifferent to offering with a Load/DRR pair rather than a price sensitive demand bid, but has the ability to reflect the cost of offering the DRR in a 3-part offer and can specify other parameters, such as minimum run times, to reflect the underlying DRR economics and physical constraints of the resource. In the Real-time market, a Commercial Node will settle at actual Real-time demand, plus actual DRR Response, and again, DRR Response will settle like any other generation resource. Meter Data and Management Agents ("MDMAs") will provide actual Metered load values at the Commercial Node defined in association with the load resource type. Meter value is also required for the Commercial Node defined in association with the unit resource type, and defined as the DRR CPNode.

7. UNIT COMMITMENT PROCEDURES

Q. WILL THE MIDWEST ISO BE COMMITTING RESOURCES TO ENSURE THAT LOAD IS MET RELIABLY DURING THE OPERATING DAY?

A. Yes. The Midwest ISO will commit resources in clearing the Day-Ahead Energy Market and throughout each Operating Day through the reliability assessment and commitment RAC process.

Q. PLEASE DESCRIBE HOW THE DAY-AHEAD ENERGY MARKET WILL BE CLEARED?

A. The Midwest ISO will use both a security constrained unit commitment ("SCUC") process and a security constrained economic dispatch ("SCED") process to simultaneously clear all supply offers and purchase bids for each hour of the Day-Ahead Energy Market. These methodologies will determine the least cost solution for serving load during each hour of the next Operating Day by efficiently allocating transmission capacity by resolving transmission constraints and by efficiently and economically committing resources to meet demand and congestion management requirements. These procedures will enable the Midwest ISO to select Resources and develop a Day-Ahead Schedule for each Resource to supply energy for each Hour of the next Operating Day. The Day-Ahead Schedule for each Resource will list the twenty-four hourly injections and withdrawals for each Market Participant whose bid and/or offer was selected in the clearing of the Day-Ahead Energy Market.

Q. WHAT ARE THE BENEFITS OF USING A SCUC METHODOLOGY TO CLEAR THE DAY-AHEAD ENERGY MARKET?

A. Through the use of SCUC, the Day-Ahead Energy Market establishes a financial result that is also physically feasible, both from a Midwest ISO and a resource perspective. This tool has been demonstrated as an efficient element of overall market design in other energy markets and ensures that Resources are available and ready to run and can physically deliver their scheduled energy during the Operating Day. The use of the SCUC process in clearing the Day-Ahead Energy Market reduces the need to commit Resources during the Operating Day. While the Midwest ISO continuously assess demand during the Operating Day, and as discussed below commits Resources to meet demand during the Operating Day, the SCUC process allows the Midwest ISO to better plan for the next day and provides better incentives for resources to participate in the Day-Ahead Energy Market.

Q. WHAT INCENTIVE HAS THE MIDWEST ISO PROVIDED TO ENSURE THAT MARKET PARTICIPANTS SUBMIT OFFERS INTO THE DAY-AHEAD ENERGY MARKET FOR COMMITMENT?

A. The Midwest ISO will guarantee recovery of the start-up and production costs (no-load) offered into the Day-Ahead Energy Market through the Market Participant's supply offer if the Market Participant's Resource is selected in clearing the Day-Ahead Energy Market and committed by the Transmission Provider.

Q. HOW DOES THE MIDWEST ISO ENSURE RECOVERY OF THESE COSTS?

A. The Midwest ISO will determine whether the Resources it committed through the Day-Ahead Energy Market will recover for the energy, the start-up and no-load components of their supply offers through the bids received and cleared to purchase energy through the Day-Ahead Energy Market. If not, the Midwest ISO will cover the shortfall through an additional revenue sufficiency guarantee payment to Market Participants whose Resources would have sustained the shortfall. The shortfall is supported through a revenue sufficiency guarantee charge assessed on all Market Participants that are scheduled to purchase energy in the Day-Ahead Energy Market. The revenue sufficiency guarantee charge will be equal to the total payments necessary to cover the energy, no load and start-up offers of resources selected in the Day-Ahead Energy Market divided by the total amount in MW of cleared bids to purchase energy and external bilateral transaction schedules for exports in the Day-Ahead Energy Market.

Q. WHY WILL THE MIDWEST ISO ASSIGN THIS SHORTFALL IN THE DAY-AHEAD ENERGY MARKET TO MARKET PARTICIPANTS WHOSE BIDS AND EXTERNAL BILATERAL TRANSACTIONS SCHEDULES CLEARED IN THE DAY-AHEAD ENERGY MARKET?

A. Through the SCUC process, the Midwest ISO is able to select and commit resources at minimum cost to meet the demand bid into the Day-Ahead Energy Market. If the Midwest ISO failed to commit the requisite resources in the Day-Ahead Energy Market, energy costs during the Operating Day would soar as intra-day commitments would be necessary to meet demand. Commitment of resources during the day prior to the Operating Day provides value to those who submit bids to purchase energy in the Day-Ahead Energy Market. Therefore, the charge is equitably levied to each Market Participant scheduled in the Day-Ahead Energy Market based on the amount of energy scheduled by the Market Participant, as those Market Participants benefit from having the Resources committed in the forward market.

Q. WILL THE MIDWEST ISO COMMIT RESOURCES AT OTHER TIMES?

A. Yes. Throughout every Operating Day the Midwest ISO will perform RAC processes as necessary to ensure that all load is met reliably, based on its forecast of demand. A RAC process will be performed after the Midwest ISO has posted LMPs, the Day-Ahead Schedules and its Load Forecast at 3:00 P.M. eastern standard time to evaluate whether sufficient Resources are committed for the next Operating Day. This particular RAC process is performed to plan for any variations in conditions that may have altered the supply and demand requirements from the time the Day-Ahead Energy Market closes at 9:00 A.M. eastern standard time and also to commit Resources to meet load forecasted to occur in the Operating Day yet did not schedule in the Day-Ahead Market.

Q. WILL THE MIDWEST ISO RECEIVE NEW OFFERS FROM RESOURCES FOR THIS PROCESS?

A. During this RAC, as is true for all RAC processes performed by the Midwest ISO, the Midwest ISO will employ Real-Time Energy Market start-up, no load and energy offers that are left available for the Real-Time Energy Market. Market Participants may also submit new Real-Time Energy Market no-load and/or start-up offers or modify their existing offers during the 3:00 p.m. to 4:00 p.m. time period of the day prior to the Operating Day. These Real-Time Energy Market no-load and start-up offers will be used and Resources will be selected to meet 100% of the Midwest ISO's load forecast for the next Operating Day.

Q. WHAT COMPUTER PROCEDURES WILL BE USED DURING THE RAC PROCESS?

A. During the RAC process the Midwest ISO will employ the same SCUC algorithm used to clear the Day-Ahead Energy Market, which minimizes the cost of committing additional Resources over a multi-hour time period, while accounting for transmission constraints and respecting Resource operating characteristics. Unlike the SCUC process used to clear the Day-Ahead Energy Market, the RAC process will consider only start-up and no-load offers and will not accept or clear energy offers. Market Participants whose Resources are selected through the RAC process will be required to submit energy offers in the Real-Time Energy Market.

Q. WHAT IS THE DIFFERENCE BETWEEN THE RAC PROCESS PERFORMED AFTER THE DAY-AHEAD ENERGY MARKET RESULTS ARE POSTED AND THOSE CONDUCTED INTRA-DAY?

A. The computer process and algorithm used is the same for all the RAC processes performed by the Midwest ISO. One difference is that Market Participants have the opportunity to change their no-load and start-up during the hour that the RAC process is performed immediately following posting of the Day-Ahead Energy Market results. The other intra-day RAC processes that the Midwest ISO may perform are not announced to Market Participants and the Midwest ISO will employ the available Real-Time Energy Market no-load and start-up offers.

Q. HOW WILL THE MIDWEST ISO ENSURE RECOVERY OF COSTS FOR RESOURCES COMMITTED THROUGH THE RAC PROCESSES IT PERFORMS?

A. On a daily basis the Midwest ISO will determine whether any Resources committed through any RAC processes performed, including the RAC process ran immediately after the Day-Ahead Energy Market results are posted, did not recover start-up and production costs (no load) through the revenues received in the Real-Time Energy Market. If there is such a short-fall, the Midwest ISO will augment the Market Participants' revenue by a revenue sufficiency guarantee payment. The revenue sufficiency guarantee payment will be supported by a charge to Market Participants who withdrew energy during the Operating Day but did not have Day-Ahead Energy Schedules and to Market Participants whose supply deviated from their Dispatch Instructions.

8. DISTRIBUTION OF MARKET DATA TO THE OMS

Q. DOES THE MIDWEST ISO BELIEVE THAT THE OMS IS ENTITLED TO REVIEW MARKET DATA?

A. Yes. The Midwest ISO believes that the OMS deserves to have accurate market data and can assist in the development of a robust and competitive electricity market if it is provided with timely information.

Q. ARE THERE CONCERNS ABOUT RELEASE OF ALL MARKET DATA ON A REAL-TIME BASIS TO THE OMS?

A. Yes. The Midwest ISO has researched the [Freedom of Information] statutes in each of the states that are in the Midwest ISO Region and has determined that these statutes greatly impair the states' ability to maintain the confidentiality of market data.

Q. WHY WOULD IT BE A PROBLEM FOR MARKET DATA TO BE SHARED WITH MARKET PARTICIPANTS?

A. Generally speaking, historical market data (i.e., data that is more than six (6) months old) should be shared with Market Participants so that they can better understand bidding behavior and how the markets actually work. However, sharing contemporaneous market data with Market Participants will risk potential negative market repercussions because it may enable parties to engage in market strategies to "game" markets.

Q. HOW IS THE MIDWEST ISO PROPOSING TO SHARE DATA WITH THE OMS?

A. First, the OMS will be entitled at any time to seek aggregated (i.e., non-confidential) market data from the Midwest ISO and/or the Independent Market Monitor ("IMM"). Second, the OMS will have the right to request that the IMM perform market studies based upon Real-Time Market data to respond to their concerns or to any perceived anomalous market behaviors. Third, the OMS will have the ability to go to the Midwest ISO and review, but not copy, real time market data.

9. ANALYSIS OF THE GRANDFATHERED AGREEMENTS IN ATTACHMENT P

Q. ARE YOU FAMILIAR WITH THE CONTRACTS THAT APPEAR IN ATTACHMENT P OF THE TARIFF?

A. Yes. There are 394 contracts currently entered in Attachment P, as this document was most recently filed with the Commission on January 28, 2004. The Commission issued an Order accepting the January 28, 2004 filing and directing a further compliance filing on March 25, 2004 in Docket No. ER04-106-001. We have estimated that the contracts amount to approximately 21,000 pages of contract language.

Q. WHAT ARE GRANDFATHERED AGREEMENTS?

A. As I use the term in this affidavit, grandfathered agreements, or "GFAs," are bilateral agreements for transmission and/or other related jurisdictional services entered into prior to September 16, 1998. The Midwest ISO reviewed and analyzed 309 GFAs in effect on the start date for the Midwest ISO's energy markets.[4] Some GFAs are for point-to-point or network transmission service. Some GFAs reflect "reciprocal use" agreements in which parties have agreed to provide access to each other's system, often for exchanges in kind and/or for set rates, and under customized energy scheduling and transmission losses requirements. Other GFAs consist of interconnection and interchange agreements whereby one party agrees to perform a service (*e.g.*, construction of facilities or transmission service) in exchange for the provision of energy services. Other agreements simply state that one party will supply, in full, all the energy and transmission needs of the other party.

Q. HAVE YOU SUPERVISED THE ANALYSIS OF THESE CONTRACTS?

A. Yes. Attorneys at the law firm Troutman Sanders LLP worked closely under my supervision in reviewing, analyzing and categorizing all of these contracts. The purpose of our analysis was to determine the nature and characteristics of these contracts as a

[4] Our analysis was based upon a population of 396 contracts. Since the Midwest ISO conducted its analysis of the GFAs, the Midwest ISO has revised Attachment P to the OATT to reflect any contracts that have expired and any contracts for companies that have joined the Midwest ISO since Attachment P was last filed. At the time the Midwest ISO conducted its analysis, the Midwest ISO estimated that there will be 309 GFAs in effect at the start of the Midwest ISO's energy markets. Since the Midwest ISO updated and re-filed Attachment P, it has not repeated its analysis based on the updated list of contracts. The Midwest ISO assessed that an update of its analysis would not provide significantly different results. Accordingly, the Midwest ISO decided to concentrate its efforts in resolving the treatment of GFAs with its stakeholders rather than revising the analysis.

whole and how they impact on capacity on the transmission system in the Midwest ISO. For example, we analyzed and categorized the contracts to determine what percentage of peak capacity is impacted by transactions pursuant to such GFAs. We also looked at what percentage of the contracts and what percentage of peak capacity is affected by contracts that contain energy scheduling, transmission losses and/or redispatch provisions.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS?

A. We found that approximately 21 percent of peak capacity in the Midwest ISO is impacted by transactions pursuant to the GFAs. Because, as explained more fully below, this number is based on MW amounts for only 146 contracts, we believe this number can go as far up as 40 percent if we had data on all of the listed GFAs.

Q. PLEASE SUMMARIZE BRIEFLY THE MIDWEST ISO'S PROPOSED TREATMENT OF TRANSACTIONS PURSUANT TO GRANDFATHERED AGREEMENTS.

A. The Midwest ISO's proposal will require that transactions pursuant to GFAs be scheduled like all other energy flows, while keeping the parties to the agreements financially unaffected to the extent feasible. The Midwest ISO is requesting that the parties to the agreement designate the entity that will be responsible for scheduling energy flows and the entity that will be responsible for all charges and payments associated with those flows. The entity responsible for scheduling must do so in compliance with the Tariff provisions and may or may not also be the entity responsible for all charges and payments. The entity responsible for the charges and payments associated with energy flows under the grandfathered agreements will be subject to marginal congestion and marginal losses charges resulting from such flows.

Q. PLEASE EXPLAIN HOW THE MIDWEST ISO INTENDS TO KEEP PARTIES TO GFAS FINANCIALLY UNAFFECTED.

A. The Midwest ISO is providing parties to GFAs with three options to choose from. Under the first option, parties to the GFAs would be allocated FTRs like all other Market Participants and would continue to be subject to congestion and losses charges. Under this option, parties would receive protection against the cost of congestion through the FTRs. Under the second option, the Midwest ISO would account for FTRs for the GFA contract paths, but would not actually allocate them. The Midwest ISO would then reimburse back the cost of congestion and the difference between marginal and average losses to the GFA responsible entity. Parties choosing this option would get full protection against congestion and losses charges under the Tariff. Under the third options parties to GFAs can choose not to be allocated FTRs, but to continue to be charged the cost of congestion and the cost of marginal losses without receiving any reimbursement for such costs. Under this last option, parties would not receive protection against congestion and losses charges, but would also not be subject to charges arising from congestion on counter flows under the FTR obligation. The Midwest ISO has decided to provide all these options and to let parties decide for themselves what works best for them.

Q. PLEASE EXPLAIN WHY THE MIDWEST ISO FOUND IT NECESSARY TO ADOPT THESE MEASURES.

A. The Midwest ISO has determined that it is vital for the success of the Energy Markets that all entities within the Transmission Provider Region are treated equally and that transactions pursuant to GFAs be accounted and held financially responsible like all other transactions. Based on our finding that up to 40 percent of peak capacity in the Transmission Provider Region would have to be "carved out" if we did not require these parties to schedule their Energy flows with us and have the option of using FTRs, it is my opinion that the success of the Energy Markets would be seriously threatened.

Q. WHY ARE THESE ISSUES CONCERNING GFAS SO IMPORTANT TO THE MIDWEST ISO?

A. These issues are so important because of the great number of GFAs operating within the Midwest ISO Region that impact a substantial percentage of the total capacity of the transmission grid over which the Midwest ISO will have responsibility. Because of this large impact, as described more fully by Dr. Hogan, granting special treatment to GFAs would impair the Midwest ISO's ability to offer open access and nondiscriminatory transmission service and would create significant market inefficiencies.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCERNS.

A. I, and a team of attorneys under my supervision, concluded a review of the 309 GFAs last fall in which we sought to determine what portion of the transmission capability of the Midwest ISO grid might be impacted by service under these GFAs. We found this figure to be somewhat difficult to estimate since not all of the contracts specify the MW amounts permissible under the GFA. Moreover, those that do specify a MW quantity, base this figure on a variety of factors, that may have changed since the contract was established, but we have no way of determining the changes.

For example, certain GFAs specify that transmission service would be provided for full requirements for a given load. That contract may have been signed in 1956 and the load specified may have been the load back in 1956. Since the contract is a full requirements contract, the contract right could have grown with the load. So the MW amount specified in the contract would underestimate the capacity that may actually be impacted today by that contract. In these cases, we assumed that, at a minimum, the specified MW amount could be impacted.

In other cases, the GFA may not specify the amount of capacity covered under the contract. For example, certain interchange agreement GFAs simply state that each party will allow the other party to use its transmission facilities, but do not specify for what amount of capacity. In certain GFAs within this group, the capacity permissible for each party may be based on the percentage ownership of a commonly owned facility. These terms make it impossible for us to determine the exact MW amount that could be impacted by the GFA.

In these cases, and in other cases where the GFA did not specify a MW amount, we looked to other sources to provide us with some indication of the MW amounts that could be impacted by the contract. We first tried to link the OASIS reservation made by these parties for the year 2002 to the GFA in question. If there was no reservation for a specific GFA, we then turned to the MW amounts specified in the FERC Form No. 1 submitted by the subject companies.

Q. WHY DID YOU NOT SIMPLY USE THE MW AMOUNTS RESERVED ON THE OASIS IN 2002 UNDER THE GFAS FOR ALL OF THE CONTRACTS?

A. Our goal was to determine what percentage of the total capacity in the Midwest ISO Region could be impacted by service provided under the existing GFAs. If we only looked at the reservations made for 2002, all we could determine is the capacity the parties to the GFAs decided to reserve for that year. Our concern is that this approach would not reflect the total potential capacity that would be impacted if parties exercised all of their rights under the existing GFAs. We only relied on the OASIS reservations and the FERC Form No. 1 information when we could not find MW amounts specified in the contracts themselves.

Q. HOW MANY OF THE CONTRACTS WERE YOU ABLE DETERMINE MW AMOUNTS?

A. Through the process I have just described, we developed MW figures for 145 GFAs. Of those 146 GFAs, we identified MW amounts in the contracts themselves for 77 of the GFAs, and developed MW figures for 29 GFAs from the OASIS and 40 GFAs from FERC Form No. 1 data.

Q. WHAT DID YOUR ANALYSIS TELL YOU?

A. We found that the total MW transmission capacity in the Midwest ISO Region that can potentially be impacted by service under the GFAs was astounding – about 20 gigawatts. This amount represents over 20 percent of the Midwest ISO grid's capability.[5] Stated

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[5] At the time of the analysis, a peak capacity in the Midwest ISO Region of 97 gigawatts was assumed. The 97 gigawatts represented the Midwest ISO Region based upon participation of the following companies: American Transmission Company, LLC, Central Illinois Light Company, Cinergy Services, Inc., Hoosier Energy Rural Electric Cooperative, Inc., Indiana Municipal Power Agency, Indianapolis Power & Light Company, International Transmission Company,

somewhat differently, parties to GFAs hold contractual rights to over 20 percent of the capacity of the grid in the Midwest ISO Region. Further, since most GFAs did not contain MW quantity figures, the percent of grid capacity affected by GFA rights is likely much higher. Given that we determined or identified MW amounts for less than half of the GFAs, I believe it is fair to extrapolate that the actual capacity that can be impacted by service under the GFAs can be as high as 40 percent, or even higher.

10. COMMISSION APPROVAL OF EFFECTIVE DATES PRIOR TO DECEMBER 1, 2004

Q. WHAT EFFECTIVE DATE IS THE MIDWEST ISO SEEKING FOR THE SUBJECT EMT FILING?

A. The Midwest ISO would like the subject filing to be effective on December 1, 2004. However, the Midwest ISO is seeking prior approval for certain of the features of the Tariff.

Q. FOR WHAT PORTION OF THE EMT IS THE MIDWEST ISO SEEKING AN EFFECTIVE DATE PRIOR TO DECEMBER 1, 2004?

A. It is essential that the FTR distribution procedures commence no later than July 15, 2004 to enable this process (including, but not limited to, an FTR auction process) to be completed by early November of 2004. This is necessary to enable parties to understand

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LG&E Energy Companies, Montana-Dakota Utilities Company, Michigan Electric Transmission Company, Minnesota Power Inc., Northwestern Wisconsin Electric Company, Otter Tail Power Company, Southern Indiana Gas & Electric Company, Southern Illinois Power Cooperative, Wabash Valley Power Association, and Xcel Energy. Since the analysis was performed, Ameren Corporation has announced that it will become a Member on May 1, 2004 and will acquire Illinois Power which will also become a Midwest ISO Member.

the financial hedging mechanisms that they will be able to use well in advance of the commencement of the full Tariff on December 1, 2004.

Q. WHAT SPECIFIC PORTIONS OF THE EMT ARE REQUIRED TO BE EFFECTIVE BY JUNE 1, 2004 IN ORDER FOR THE FTR PROCEDURES TO BE ACCOMPLISHED IN A TIMELY MANNER?

A. It is necessary for all Market Participants (particularly those that are parties to GFAs) to be required to comply with the designation of GFA Scheduling Entity provisions of the Tariff, no later than June 1, 2004. A related Tariff provision that must be in effect on that date is the mandatory Expedited Dispute Resolution procedures found in Section 12A of the Tariff which are necessary if parties to GFAs are unable to designate a GFA Scheduling Entity by June 1, 2004.

Q. ARE THERE ANY OTHER EMT PROVISIONS THAT THE MIDWEST ISO IS SEEKING AN EFFECTIVE DATE THAT IS PRIOR TO DECEMBER 1, 2004?

A. Yes. The Midwest ISO has been working with its stakeholders to develop market milestones to measure the progress of the development of the Tariff. In particular, the Midwest ISO stakeholders have requested that "market trials" be conducted well in advance of December 1, 2004 so that Market Participants would gain experience with the operation of the Tariff and that the Midwest ISO would gain experience with working with the Market Participants.

Q. WHAT WILL THE MARKET TRIALS INVOLVE?

A. A Real-Time Market Operations Trial, consistent with the Midwest ISO's Performance Metric #45.4. (In part, this metric requires that the Midwest ISO demonstrate the ability to support "successful Real-Time Market operations for 2 one-hour periods" as a precursor to commencing the Tariff on December 1, 2004.) These trials are currently planned to be held during selected hours during September and October of 2004. These activities include a short duration test that would not be financially binding under the Energy Markets Tariff . . . [b]ased upon a small percentage of online generators following Midwest ISO's direction with any inadvertent settled as much as possible among Midwest ISO members. This test would not be designed to familiarize Market Participants with bidding strategies or validate settlement processes but would concentrate on the reliability aspects of the Market.

Q. ARE THERE ADDITIONAL MARKET TRIALS TESTS THAT WILL BE CONDUCTED?

A. Yes. The Midwest ISO is still working with its stakeholders to define and implement market trials testing.

Q. WHAT EFFECTIVE DATE(S) ARE THE MIDWEST ISO SEEKING TO ENABLE THE MARKET TRIALS TO BE CONDUCTED?

A. The Midwest ISO is still developing a precise schedule of trials. However, to successfully conduct any such trials, it will be necessary for certain elements of the Tariff to become effective during the selected hours of testing.

Q. WHEN WILL THE MIDWEST ISO SEEK FERC AUTHORITY TO CONDUCT THE MARKET TRIALS?

A. Once the market trials are better defined, the Midwest ISO will make a supplemental filing in the subject docket seeking appropriate Commission approval to conduct such trials.

V. COMPATABILITY OF MIDWEST ISO MARKETS WITH PJM'S MARKETS

Q. WHY IS IT IMPORTANT FOR THE MIDWEST ISO'S ENERGY MARKET TO BE COMPATIBLE WITH THE NEIGHBORING PJM INTERCONNECTION, L.L.C. ENERGY MARKETS?

A. As the Commission first announced on July 31, 2002, the formation of a common market between the Midwest ISO and PJM will minimize any seams issues and should result in substantial cost savings. In that order, the Commission requested that such a functional common market be established by October 1, 2004. Compatibility between the two markets will also make each of the energy markets more efficient and liquid.

Q. HAVE YOU REVIEWED THESE TWO MARKETS?

A. Yes. I am familiar with the PJM market and I have determined that it is generally compatible with the Midwest ISO's Energy Markets.

Q. WHAT STEPS HAS THE MIDWEST ISO TAKEN TO ENSURE THAT ITS ENERGY MARKET WILL BE COMPATIBLE WITH THE PJM MARKETS?

A. During 2003, the Midwest ISO and PJM spent many months discussing the similarities and differences of their markets. The result of these discussions was a Joint Operating Agreement ("JOA") that was filed with the Commission and conditionally approved on March 18, 2004. This agreement establishes effective operating parameters to enable the parties to work out all differences between the two energy markets.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Q. DO YOU ATTEST THAT THE FOREGOING TESTIMONY IS TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE?

A. Yes.

Exhibit No. ___ (MISO-4)

Exhibit No. __ (RRM-1)

Examples of Payment Calculations for Over Generation and Under Generation Deviations

A. Examples for Over Generation

1. Generator Base Point set to 100 MW (no Reg up). The Generator's actual generation is 113 MW. This creates an excess of 3 MW (Actual output - (100 MW base point + 10MW dead band) = 3MW). Payment = 60% of LMP for 3 MW excess, 100% of LMP for 110 MW.

2. Generator Base Point set to 100 MW (5 MW Reg up). The Generator's actual generation is 119 MW. This creates an excess of 4 MW (Actual output - (100 MW base point + 5 MW Reg up + 10MW dead band) = 4MW). Payment = 60% of LMP for 4 MW excess, 100% of LMP for 115 MW.

B. Examples for Under Generation

1. Generator base point set to 100 MW (no Reg down). The generator's actual output is 88 MW, creating a shortfall of 5 MW (100 MW base point - 10 MW dead band - actual output = 2 MW). Payment = 60% of LMP for 2 MW shortfall, 100% of LMP for 86 MW (88 MW - 2 MW shortfall outside of dead band = 86 MW).

2. Generator base point set to 100 MW (5 MW Reg down). The generator's actual output = 80 MW, creating a shortfall of 5 MW (100 MW base point - 5 MW down Reg - 10 MW base Dead Band - actual output = 5 MW). Payment = 60% of LMP for 5 MW shortfall outside the dead band, 100% of LMP for 75 MW (80 MW output - 5 MW shortfall = 75 MW).