To: The Midwest Independent Transmission System Operator

COMMENTS OF THE ORGANIZATION OF MISO STATES ON DRAFT TRANSMISSION AND ENERGY MARKETS TARIFF

The Organization of MISO States ("OMS") appreciates the opportunity to offer the following comments on the February 25, 2004, draft Transmission and Energy Markets Tariff (TEMT) scheduled for filing with the Federal Energy Regulatory Commission (FERC) on March 31, 2004.

These comments address the following issues: 1) The MISO's FTR allocations and grandfathered agreements; 2) Requirements to participate in the energy market; 3) Self-scheduled generation and bilateral contracts; 4) Control area responsibilities and multiple entities in one control area; 5) Security-constrained unit commitment and security–constrained economic dispatch in the day-ahead market; 6) State Commission access to confidential data; 7) Staged implementation of the market; 8) Market monitoring and mitigation mechanisms; 9) Performance metrics; 10) Resource adequacy and capacity markets; and 11) Proposed business practice manuals.

I. BACKGROUND

On December 17, 2002, the MISO filed with the Commission a Petition for Declaratory Order seeking the Commission's approval of preliminary market rules regarding the MISO's energy markets. On February 24, 2003, the Commission issued an Order that generally approved the MISO's Petition. On July 25, 2003, the MISO submitted to the Commission the Third Revised, First Volume of the MISO's Open Access Transmission and Energy Markets Tariff ("TEMT"). The purpose of the TEMT filing was to comply with the Commission's February 24, 2003 declaratory order and to submit for filing with the Commission those terms and conditions necessary for the implementation of the MISO's day-ahead, real-time energy markets and FTR energy markets on March 31, 2004. The TEMT also contained certain revisions to the existing provisions of the MISO OATT that would be necessary for the implementation of the Energy Markets and the continued provision of transmission service within the MISO footprint.

On September 15, 2003, the OMS filed its comments regarding the TEMT. In short, the OMS stated that the TEMT was "headed in the right direction", but certain key elements needed to be addressed if a properly functioning, competitive wholesale market was to be established in MISO's footprint. The OMS' September 15 comments provided 12 recommendations on pages 23 and 24 of its comments that addressed the areas of concerns the OMS had with the existing TEMT.

On October 17, 2003, at the urging of its Advisory Committee, MISO withdrew its TEMT without prejudice, to provide MISO and its stakeholders additional time to ensure that effective reliability tools were in place and being operated correctly and to allow a more complete TEMT to be refiled on March 31, 2004.

On February 11, 2004, the MISO submitted to its stakeholders for review and comments a draft copy of certain portions of the revised TEMT. On February 25, 2004, the MISO submitted to its stakeholders an updated copy of its February 11, 2004 draft TEMT, with additional tariff Modules for stakeholder review.

II. SUMMARY OF MISO's DRAFT REVISED TEMT

The Revised TEMT includes the following preliminary provisions: (1) Module A, Common Tariff Provisions, the definitions used in the TEMT ; (2) Module B, Transmission Service; (3) Module C, Transmission Provider Energy Markets, Scheduling and Congestion Management; (4) Module D, Independent Market Monitoring and Mitigation provisions; (3) Section 12A of Module A, regarding Expedited Dispute Resolution procedures applicable to Grandfathered Agreements; - and (5) Attachments Y and Y-1 governing System Support Resources. MISO intends to file all of its Open Access Transmission Tariff attachments and schedules on March 31, 2004, some of which have been changed. In addition to these preliminary TEMT provisions, MISO also provided stakeholders with draft business practice manuals that are intended to facilitate the implementation of the following: (1) the day –ahead energy markets; (2) the real-time energy markets; (3) financial transmission rights; (4) coordinated reliability, dispatch and control; (5) settlements; (6) registration; (7) definitions; and (8) market protocol and rules. (The BPMs are not part of the TEMT).

The Midwest ISO has indicated to its stakeholders that these documents represent an early state in the continued development of the TEMT and that additional progress will produce further refinements of the TEMT terms and conditions.

III. OMS POSITION & RECOMMENDATIONS

The OMS believes that the TEMT will prove to be a cornerstone in the MISO's establishment of a competitive wholesale electricity market in the Midwest. To that end, the OMS has taken a keen interest in the development of the TEMT. The OMS both acknowledges and appreciates the amount of consultation and discussion that has occurred between the MISO and its stakeholders to develop the revised TEMT filing.

The OMS is encouraged by the direction that the TEMT is headed. However, as discussed below, key issues need to be addressed for a properly functioning, competitive wholesale market to be established in the MISO's footprint. The MISO's continued effort to take a cooperative approach regarding the development, implementation and fine-tuning of the terms contained in the TEMT encourages the members of the OMS. Accordingly, the OMS stands ready to assist both the Commission and the MISO in achieving this goal. To that end, the OMS makes the following recommendations:

<u>FTRs and Grandfathered Agreements</u> - 1) The Midwest ISO's nomination of FTR for retained grandfathered agreements ("GFAs") cannot exceed the corresponding tier limits for transmission customers retaining any portion of their GFAs; 2) If there are any revenue inadequacies (excesses) associated with retaining GFAs, the costs (payments) of these revenue inadequacies (excesses) should be spread over a large group of market participants in proportion

to the megawatts of FTRs received in the allocation process, including the megawatts of FTRs received by the Midwest ISO for retained GFAs (i.e., those that retain GFAs should not be exempt from their overall share of uplifts resulting from their decision to retain GFAs); 3) The MISO should add three elements to its proposed tariff in order to have a safety net that is sufficient to meet FERC's requirement to keep existing transmission customers whole. These elements are discussed in Section IV.A.3.C of the document; 4) The MISO should take into account diversity of use through monthly nominations of on-peak and off-peak CFTRs in tiers 2, 3, and 4 as soon as possible; 5) The MISO should take into account the infeasibility caused by loop flows assumed within its footprint by issuing counter-flow FGRs that correspond to the mega-watt capacities of these assumed loop flows; and 6) In cases where the prorating of FTRs from base-load generation cannot be restored by issuing counter flow FTRs from base-load generation sources, and this prorating of FTRs results in harm to the transmission customer, the Midwest ISO should consider whether or not restoring the full point-to-point FTRs and issuing counter-flow FGRs to the transmission customer will reduce the harm to the transmission customer. If harm is reduced, then the Midwest ISO should implement this alternative.

Requirements to Participate in the Energy Markets - Based on previous assertions by MISO, the OMS supports the MISO's proposed market participant language.

Self-Scheduled Generation and Bilateral Contracts - Based on OMS' discussion with MISO Staff, the OMS is confident that load-serving entities will be able to continue to serve their load with the same generation that is used today.

Control Area Responsibilities and Multiple Entities in one Control Area – The OMS requests that MISO provide more clarity on this issue, per the discussion below.

Security-Constrained Unit Commitment and Security-Constrained Economic Dispatch in the Day-ahead Market – MISO's SCUC and SCED will allow for the lowest cost resources to be scheduled while considering the operational ability of generating units available and any transmission constraints. Accordingly, the OMS recommends that MISO implement the proposed SCUC and SCED.

State Commission Access to Confidential Information – The OMS supports the improvements, mutually agreed upon by the OMS and the MISO and already incorporated into the existing TEMT. As a result, OMS has no recommendations at this time.[1]

Western Seams Issue – The OMS recommends that MISO work to resolve all critical seams issues prior to the implementation of the energy markets (particularly those in the Western MISO region where half of MAPP region is in the market and half of MAPP region is out of the market).

Market Monitoring and Mitigation – With regards to market monitoring, the OMS recommends that the MISO's market monitor be authorized in the following manner: 1) Access to fuel information; 2) Monitor intra-company transactions; 3) Review energy company mergers

[1] This concurrence is based on our understanding that the tariff does not preclude discussion of confidential information with other persons authorized to receive it.

for their market power ramifications; 3) Review the commercial implications of regional reliability council actions; and 4) Review inter-RTO agreements and agreements with transmission owning entities that are unaffiliated with RTOs. With regards to market mitigation, the OMS may request additional protections in conjunction with other components of the MISO TEMT.

Performance Metrics - 1) The Verification Plan should be finalized in time to enable PA Consulting to provide the OMS with thorough and accurate measures of MISO's readiness to properly implement Day 2 markets on December 1, 2004; 2) On or before March 31, 2004, MISO should state its expectations regarding both the overall need for verification activities and the date of the (initial) finalization of the Verification Plan; 3) MISO should clarify who is accountable for the provisions of the Verification Plan that PA Consulting will use to assess whether or not MISO has met each "performance metric"; and 4) MISO should explain its expected role of stakeholders, including the OMS, in developing the Verification Plan.

Resource Adequacy and Capacity Markets – The tariff language in Module E should be revised to address the following issues: 1) It is not clear that the resource adequacy provisions will do no financial or other harm to native load or any other customers; 2) The failure to recognize the potential market-to-market seams with PJM in portions of MISO in the East and the market-to-non-market seams in the MAPP portions of MISO in the West; 3) The need for the Alternative Capacity Resource section to be clarified to include mechanisms that allow the participation of demand response and load reduction options in addition to the interruptible demand option; 4) Whether renewable resources will be included as designated network resources; 5) The failure to discuss if there are any consequences for non-compliance with the standards; 6) The omission of language to require verification or tests for certifying capacity ratings; and 7) The failure to clarify if there are any reporting requirements relating to long-term forward-looking system requirements.

Business Practice Manuals – The OMS urges MISO to make sure the information necessary to determine the appropriate rates and to facilitate the resolution of disputes is in the tariff on file with the FERC. Our concern is that necessary details are in the Business Practices Manuals, which will not be filed with the FERC, rather than in the tariff.

IV. DISCUSSION

A. FTR Allocations and Grandfathered Agreements.

1. Broad Policy Objectives for FTR Allocations

The starting point to understand the policy objectives related to FTR Allocations is FERC's *Midwest Independent Transmission System Operator, Inc.,* order dated February 24, 2003. In that Order, FERC stated:

> The Midwest ISO states that its initial FTR allocation has several important objectives: 1) **to hold existing transmission customers whole with respect to congestion-related charges under MISO Day-2 operation to the extent**

> **possible given the objective of simultaneous feasibility**; 2) to provide an allocation of FTRs that is simultaneously feasible in a security constrained power flow; and 3) to provide an allocation that is fair and consistent with how the underlying costs of the system are recovered. We recognize that the Midwest ISO has the difficult task of trying to protect parties' existing rights while ensuring that FTRs are simultaneously feasible. While we believe it is important to balance all three stated objectives, **we give more weight to the first objective**. We continue to believe that customers under existing contracts, both real or implicit, should continue to receive the same level and quality of service under a standard market design. We remain concerned that the outcome of the initial allocation, especially the application of a pro rata mechanism, will not meet Midwest ISO's first objective of keeping customers whole.[2]

The Commission clarified in *Midwest ISO Inc.* that it was not directing MISO to abandon its proposed simultaneous feasibility test "at this time."[3] Approximately two months later, FERC issued its White Paper. The White Paper states:

> Under the Wholesale Power Market Platform, customers in RTOs that use locational pricing along with network transmission service would have firm physical transmission service, and customers with FTRs would be **protected from congestion costs**.
>
> … FTRs allow customers to schedule service according to the paths specified in their rights, with **no risk of congestion charges**. There would also be no risk of curtailment, absent a force majeure event such as the loss of a transmission line.
>
> … In the Final Rule, for RTOs or ISOs that have not already addressed this issue, **these rights would be allocated according to existing contracts and existing service arrangements in order to hold customers harmless.**[4]

The White Paper's Appendix similarly provides specific assurance that existing firm transmission rights would be provided the opportunity for full protection from congestion costs through allocation of FTRs. Specifically,

> If an RTO or ISO uses location pricing, it *must* ensure that each existing firm customer (including transmission owners with a service obligation for native load) has **the opportunity to obtain FTRs equivalent to that customer's existing firm rights.** We will ensure not only that existing customers retain their existing rights but also that they have the ability to **obtain rights for future load growth**. Customers who paid for Transmission for load growth can retain the FTRs for that capacity. The FTRs that are offered by the RTO or ISO must, in the aggregate be consistent with the physical limitations of the transmission system.[5]

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[2] *Midwest Independent Transmission System Operator, Inc*, 102 FERC ¶61,196 (2003), at P. 64, emphasis added.
[3] *Ibid*, at P 68
[4] White Paper, at 10, emphasis added
[5] Appendix A, at 7-8 & n. 8, emphasis added; footnotes 6 and 7 omitted

The OMS' objective is to ensure that this opportunity to receive full protection occurs and address how to share possible uplifts when there is a revenue inadequacy resulting from the FTR allocation process. Appendix A states that the OMS is to:

> . . . ensure that each existing firm customer receives FTRs or ARRs, based on the regional choice, equivalent to the customer's existing firm rights. This includes whether **any revenue shortfalls would be recovered through an uplift charge that applies to all customers in the region or over narrower class of customers**, e.g., only to customers in certain zones within the region.[6]

The FERC's policy statements on FTR allocation indicate that FTRs must first be allocated to protect customers from the cost of congestion they do not incur today under existing contracts and arrangements for firm transmission service.

Given this broad policy objective, the FERC left to the OMS the policy issue of the extent to which an allocation of FTRs could result in revenue shortfalls, and if so, how to allocate the recovery of these shortfalls through uplift charges; e.g., over the entire Midwest ISO footprint or from a more narrowly defined group.

2. Overview of the Midwest ISO's Proposed FTR Allocation Process

a. Principles Applied by the Midwest ISO for FTR Allocations

The Midwest ISO tariff proposes a four-tier nomination process for the allocation of FTRs. This proposal takes from the major strengths of two previous proposals and eliminates the major weaknesses of each. In addition, the proposal incorporates a treatment of Grandfathered Agreements (GFAs) that addresses concerns regarding exposure to congestion costs and the payment of marginal losses.

- The proposed four-tier nomination process allows all those with existing firm transmission rights to nominate the FTRs on an equivalent basis.[7]

- The nominations made in the earlier tiers are less likely to be prorated because of lack of simultaneous feasibility. This maximizes the possibility of a non-prorated allocation of FTRs believed by participants to be most valuable in providing a hedge to congestion costs.

- The possibility of harm from the prorating of highly valuable FTRs is taken into account by allowing prorated FTRs from base-load generation sources in the first two tiers to be restored by requiring non-nominated, counter flow FTRs from base-load sources to be taken.[8]

[6] Appendix A, at 17, emphasis added
[7] Draft Module C @ 44.2.2, p.p. 172-176
[8] Draft Module C @ 44.2.3, p.p. 176-179

- This restoration of prorated FTRs from base-load generation sources through requiring non-nominated, counter flow FTRs from base-load sources to be taken is limited to the first three years of FTR allocations.[9]

The general principle being applied in the Midwest ISO's FTR allocation proposal is that *If an entity was using a base-load generation source to serve its load prior to the MISO Day 2 market, it could not immediately opt out of continuing to do so by not taking a counter flow FTR when this results in prorating a FTR that another entity had nominated from a base-load generation source.*

b. Details of the MISO Proposed FTR Allocation Process

In the first tier, those with existing firm transmission rights are allowed to nominate up to thirty-five percent of the maximum megawatts they are eligible to hold. For network integration service, the maximum FTR megawatts are determined by the provider's forecast of summer peak load. For point-to-point transmission service, the maximum FTR megawatts are determined by the transmission customers' reserved capacity. The first tier nominations are for annual FTRs (do not change by season or by time of day), but the simultaneous feasibility test is performed on a seasonal and time-of-day basis to better reflect changes in the topology of the transmission network.

Those with GFAs can elect not to take FTRs, but instead to retain their GFA ("retained GFAs") and schedule transactions associated with retained GFAs in the Day-Ahead market. Those retaining GFAs would not be charged congestion costs on transactions related to the retained GFA that are scheduled in the Day-Ahead market. For GFA transmission service electing not to take FTRs, the Midwest ISO will instead, submit a corresponding nomination for those FTRs in tier 1. Like all other nominated FTRs, those submitted by the Midwest ISO will be subject to prorating if they are not simultaneously feasible. The FTRs placed into the first tier of the nomination process by the Midwest ISO will count towards the 35% limit for the transmission customer electing to retain GFAs.

The second-tier nominations go from 35% up to 50% of maximum eligible megawatts, and nominations are allowed to change by season and time of day. Restoration of prorated FTRs from base-load sources through requiring counter flow FTRs from base-load sources to be taken, will occur after the simultaneous feasibility test and prorating from the second tier. The third (up to 75%) and fourth (up to 100%) tiers are also allowed to change by season and time of day.

Finally, the concern about GFAs having specified terms for losses compared to the marginal loss requirement of the Midwest ISO tariff has been addressed by allowing those who chose to schedule transactions for GFAs to be directly refunded the difference between marginal and average losses rather than going into a larger pool for similar, but not exact, refunds.

3. Two Major Policy Issues with the Midwest ISO Proposed FTR Allocation

a. Policy Issue 1: Proposed FTR Treatment for Retained GFAs

[9] Draft Module C @ 44.2.2, p.171

The proposal by the Midwest ISO is to include in the first tier all FTRs for retained GFA transmission service that transmission customers elect not to convert to FTRs (called Option B GFAs in the draft tariff).[10] In the following subsection of the draft tariff, it states, "In situations where the MW quantity of Option B Grandfathered Agreements exceeds the Tier I limit, Tier I will include only Option B Grandfathered Agreements and any residual Option B Grandfathered Agreements will be carried over to subsequent Tiers for purposes of determining nomination eligibility." The OMS interprets this language to mean that if MISO is nominating FTRs for retained GFA transmission service, that such GFA nominations count for the total FTRs that an individual transmission customer can nominate in any tier, have priority in the nominations over other possible nominations by the transmission customer and cannot exceed the limits for that transmission customer for any tier.

The following example will explain our understanding. Suppose a transmission customer has a peak demand of 1,000 MW, with 500 MW from GFAs and the remaining 500 MW from network resources. The transmission customer decides to take 600 MWs in FTRs, 500 MWs for network resources and 100 MWs for GFAs. This leaves 400 MWs in retained GFAs that the transmission customer will schedule, and for which these schedules will not be subject to congestion cost. The Midwest ISO will then submit a nomination for 350 MWs of FTRs for the retained GFAs in tier 1; i.e., 35% of the 1,000 MW peak of the transmission customer. Since the 35% limit for tier 1 is met by the Midwest ISO's nomination of FTRs, the transmission customer may not nominate any FTRs in tier 1. In tier 2, the Midwest ISO will nominate the remaining 50 MWS of FTRS for the retained GFAs, and the transmission customer may nominate up to 100 MWs of FTRs, resulting in a tier 2 nomination of 150 MWs (= 15% * 1,000 MW).

If this is indeed the Midwest ISO proposal, the OMS is in agreement with this approach. If FTRs for all retained GFAs were nominated in the first tier, this would likely result in a greater level of FTR prorating of nominated FTRs in both the first and second tiers. This may occur when the megawatts associated with retained GFAs exceed the 35% limit set for the first tier. The Midwest ISO may hear the argument that including FTRs for all retained GFAs in the first tier will provide it with a level of revenues needed to minimize the amount of uplift associated with providing GFAs with the option to schedule at zero congestion costs in the Day-Ahead market. However, if the level of prorating to FTRs from including FTRs associated with all retained GFAs in the first tier is significant, it is not clear that requiring counter flow FTRs from base-load sources will be sufficient to provide those holding existing firm transmission rights with sufficient FTRs to keep their congestion costs at current levels. As an alternative to the Midwest ISO proposal to include FTRs for retained GFAs in the first tier, the OMS recommends:

<u>Recommendation on P1.a</u>: The Midwest ISO's nomination of FTRs for retained GFAs cannot exceed the corresponding tier limits for transmission customers retaining any portion of their GFAs.

This recommendation supports the OMS' understanding of the Midwest ISO draft tariff language on this issue. In this regard, the OMS Board of Directors has adopted principles for uplifting possible revenue inadequacies that could result from the FTR Allocation process:

[10] Module C, at Section 44.2.2.a

1) Uplifts of FTR revenue inadequacies should satisfy FERC's *Midwest ISO* order:[11]

"… to hold existing transmission customers whole with respect to congestion-related charges under MISO Day-2 operation to the extent possible given the objective of simultaneous feasibility."[12]

Further,

"… these rights would be allocated according to existing contracts and existing service arrangements in order to hold customers harmless."[13]

and

"… ensure that each existing firm customer receives FTRs or ARRs, based on the regional choice, equivalent to the customer's existing firm rights. This includes whether any revenue shortfalls would be recovered through an uplift charge that applies to all customers in the region or over narrower class of customers, e.g., only to customers in certain zones within the region."[14]

2) Uplifts of FTR revenue inadequacies should not be applied when costs can be allocated **to and recovered from cost causers.**

3) Uplifts of FTR revenue inadequacies should not provide incentives to discourage or **delay the implementation of congestion mitigation measures.**

The Midwest ISO proposed FTR nominations procedure for retained GFAs more fairly uplifts the potential cost of allowing transmission customers to retain GFAs rather than imposing those costs on specific transmission customers who did not cause them (OMS Uplift Principle 1 holding existing transmission customers whole). Transmission customers whose FTR nominations are prorated because of the choice to retain GFAs by other transmission customers are not the cost causers and should not have to bear the entire burden of the costs (OMS Uplift Principle 2 – there are no cost causers). Such a result would violate FERC related principles by elevating simultaneous feasibility (revenue adequacy) above keeping existing customers whole (OMS Uplift Principle 1 - to hold existing transmission customers whole).

The OMS did not find any draft tariff language regarding the question of recovery of any revenue inadequacies from transmission customers deciding to retain GFAs or possible distribution of revenues if the Midwest ISO recovers more in FTR credits for FTRs that it is allocated for retained GFAs. It is the understanding of the OMS that it was not included in the draft tariff because it remains an open issue. At this time, the OMS provides the following guidance on this issue.

<u>Recommendation on P1.b</u>: If there are any revenue inadequacies associated with retaining GFAs, the costs of these revenue inadequacies should be spread over a large

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[11] *Midwest ISO*, at P 64
[12] FERC's White Paper, at 10
[13] *Ibid*
[14] Appendix A, at 17.

group of FTR holders in proportion to the megawatts of FTRs received in the allocation process, including the megawatts of FTRs received by the Midwest ISO for retained GFAs (i.e., those that retain GFAs should not be exempt from their overall share of uplifts resulting from their decision to retain GFAs).

The point of this recommendation is twofold: 1) to spread the cost in proportion to megawatts, not FTR payments; and 2) to not exclude those who choose to retain GFAs from bearing a portion of these costs. On the other hand, this recommendation is not meant to exclude the possibility that the revenue inadequacy from retained GFAs could be allocated to sub-regions within the Midwest ISO before it is allocated to FTR holders within a sub-region based on megawatts of allocated FTRs.

b. Policy Issue 2: Proposed Restoration of Prorated FTRs

In tiers 1 and 2, where FTRs for base-load generation source are likely to be nominated, the Midwest ISO had initially proposed giving all transmission customers a full allocation of FTRs and uplifting any possible revenue inadequacies that might result from not meeting the simultaneous feasibility condition. However, the Market Subcommittee voted instead to prorate any FTR allocations that did not meet the simultaneous feasibility requirement in tiers 1 and 2. The Midwest ISO has subsequently proposed to restore any prorated FTRs for base-load generation sources by requiring counter flow FTRs that were not nominated in tiers 1 and 2 to be taken under the following conditions:

a) Only counter flow FTRs from base-load generation sources would be used as candidates for restoring prorated FTRs from base-load generation sources;

b) Only counter flow FTRs that contribute to the restoration of a prorated FTR from base-load generation would be used;

c) A counter flow FTR would not be required to be taken during periods that the base-load generation source is scheduled to be down for maintenance or forced out for an extended period of time; and

d) The counter flow FTR megawatts used for restoration must be simultaneously feasible.

To address the issue of the extent to which an FTR Allocation might result in customers incurring congestion costs they do not incur today because of prorating, the OMS Board of Directors adopted the following principles related to restoration of nominated FTRs that were prorated in the Midwest ISO's FTR allocation process.[15]

c. OMS Principles Regarding Restoration of Nominated FTRs

1. **Hold Harmless** - The initial FTR allocation, restoration and uplift processes should ensure than an existing transmission customer does not have to pay for additional

[15] The OMS Board adopted these principles at its February 25 meeting.

congestion costs compared to what it would have paid if the market structure had not been changed.

2. **Enforceability** - There must be an enforcement mechanism to ensure that the initial FTR allocation, restoration and uplift processes hold harmless existing transmission customers.

3. **Eligibility** - If prorating of nominated FTRs results in an existing transmission customer being harmed, the prorated FTRs would be eligible for restoration.
4. **Restoration Process –** to the extent that present-day financial outcomes for holders of existing firm transmission service do not reflect enduring costs caused by others, the restoration of prorated FTRs should, to the maximum extent possible, reflect those present-day financial outcomes.

5. **Transition –** any requirement for customers to take counter flow FTRs should be limited to the first three years of FTR Allocations.

6. **Safety Net –** Only in cases of significant financial harm to an existing transmission customer, where either base FTR restoration cannot be achieved without violating simultaneous feasibility or where base FTR restoration is not sufficient, should forms of uplifting the cost of the FTR restoration be used.

The Midwest ISO proposal for FTR restoration in tiers 1 and 2 meets the OMS principles numbers 3, 4 and 5 for FTR restoration. However, the Midwest ISO proposal does not clearly address the other three principles for hold harmless, enforceability and providing a "safety net" when the FTR restoration process does not result in sufficient FTRs to prevent significant financial harm to an existing transmission customer. The OMS requested that the Midwest ISO present a "safety net" to cover a situation in which one or more transmission customers would be significantly harmed by its proposed FTR allocation procedure. The safety net proposed by the Midwest ISO is that harm to transmission customers be taken up on a state-by-state basis, in which the states could request that prorated FTRs be restored, but such requests will only be granted "if accompanied by instructions as to how the required Counter Flow FTRs, or their costs, are to be allocated among jurisdictional Market Participants of that state."[16]

There are two fundamental flaws in the Midwest ISO proposal. First is the fact that most states' regulatory authorities do not have jurisdiction over all load-serving entities within their state. Second is the fact that redistribution among state jurisdictional utilities is not a sufficient condition for meeting the FERC's requirement to keep existing transmission customers whole. For example, if all of the load-serving entities within a particular state are harmed by the Midwest ISO FTR allocation, redistribution within the state could not eliminate the harm.

<u>Recommendation P2</u>: The Midwest ISO should add three elements to its proposed tariff in order to have a "safety net" that is sufficient to meet FERC's requirement to keep existing transmission customers whole:

[16] Draft Module C, at 44.2.4, p. 179

1) Set out ex ante criteria in its tariff by which to determine if the FTR Allocation process results in harm to a transmission customer;
- How will harm be measured and over what period of time?
- What existing level of congestion costs should be included?

2) Include a process for FTR restoration that would eliminate the harm; and
3) Include a tariff provision for uplifting the possible revenue inadequacy resulting from the FTR restorations required to eliminate the harm.
- How will harm to others from the uplift be taken into account?

In addition or as an alternative, the Midwest ISO could propose an ex post procedure to determine after the fact if a transmission customer has been kept whole.

The OMS realizes the difficulty in developing a safety net that applies to all and does not simply shift harm from one individual to another group of individuals. The OMS will work with the Midwest ISO in developing an appropriate approach to a safety net, and realizes that developing such details will take more time than is available to make the March 31 deadline for the Midwest ISO tariff filing. In much the same procedure that is being used for supply adequacy, the OMS proposes that the Midwest ISO would establish a working group to develop the details required for the additions of the above elements to the tariff and that these details be submitted to the FERC by May 31, 2004.

B. Other Technical Issues with the FTR Allocation Proposed by the Midwest ISO

1. Technical Issue 1: FTR Time Periods Related to Diversity

In envisioning FTRs as a hedge against congestion costs when the transmission customer is using that transmission right to serve load, the FERC may not have anticipated some of the complexity that results when moving from the existing "physical" transmission rights to a system involving "financial" transmission rights.[17] Specifically, the condition requiring simultaneous feasibility for FTRs is more rigid than requiring simultaneous feasibility for physical transmission rights.

When transmission reservations are sold, transmission providers would take into account the **diversity of use** of those reservations by the various transmission customers. For example, a flowgate that would be overloaded if all transmission customers were simultaneously using the maximum level of their physical transmission reservations would in actual practice not be overloaded because these transmission reservations would not be simultaneously scheduled for use at their maximum levels. However, holders of FTRs receive (or make) payments whether or not they are physically using the generation source to serve load. Thus, physical rights that are

[17] The terms "physical" and "financial" have been used to contrast the existing system of managing congestion through rights to schedule a physical injection into the power grid that are sold at an embedded cost rate for transmission service on a first-come, first-served basis compared to the proposed system in which physical injections are based on a market system involving financial offers and congestion is managed by a least-cost dispatch subject to transmission constraints. While there are both physical and financial aspects to both systems, this characterization primarily focuses on how congestion is managed; i.e., through the sale or allocation of rights to physically schedule injections versus the sale or allocation of rights to be paid or pay the congestion costs.

feasible because of diversity of use will be infeasible when exchanged for FTRs that require payments irrespective of use.

There are two positions on how to properly take into account diversity of use. First, if diversity of use is primarily a time-of-day and seasonal phenomena, the way to account for diversity of use is to specify different assignments of candidate FTRs ("CFTRs") by time-of-day and seasons. This is the approach taken by the Midwest ISO by having peak and off-peak CFTRs assigned for summer, fall, winter and spring seasons.[18] The shorter the period over which the CFTRs are assigned, the more likely the assignments will reflect diversity of use. Some market participants wanted monthly assignments of CFTRs, but the Midwest ISO stated that since it was going to allow nominations of FTRs for all four tiers, the process of determining simultaneous feasibility for 96 nominations (12 months * 2 rating periods * 4 tiers) versus 32 nominations (4 seasons * 2 rating periods * 4 tiers) would triple the time for the nomination process. With it taking one day to run each simultaneous feasibility test, the Midwest ISO believed that going to monthly allocations would take too long. Thus, it proposed to stay with four seasons.

Second, if diversity of use occurs within a season or a time-of-day period, the way to account for diversity of use is to prorate FTR payments based on day-ahead scheduled use of generation sources.[19] When there is a revenue inadequacy on a specific flowgate, transmission customers fully scheduling their transmission reservation might still receive a full hedge, as transmission customers not fully scheduling their transmission reservation would receive a reduced payment based on their scheduled use.[20]

In the system of physical rights where schedules submitted by transmission customers intending to use their firm transmission reservations exceed the security limits of a flowgate, a TLR would be called requiring transmission customers impacting the flowgate to curtail their schedules on a prorated basis and then redispatch generation to meet their load obligations. If their transaction is called for a TLR, then they must add the redispatch costs to what was the original cost of the transaction and this can be very disruptive to bilateral markets for electricity. In the same way prorating of FTR payments can be very disruptive to the bilateral markets because of the added uncertainty that prorated FTR payments would bring to short-term contractual arrangements. Neither the buyer nor the seller could be assured of the price at which transactions would take place because of potential loss of FTR payments.

[18] As noted earlier, this does not apply to FTRs nominated in tier 1 where the allocations are annual. Instead, it applies to FTRs nominated in tiers 2, 3 and 4.

[19] Recall that the Midwest ISO will settle FTRs in its day-ahead market.

[20] Keep in mind that in most instances, TLRs are called on schedules corresponding to non-firm transmission service, and less frequently for schedules involving firm transmission service. Therefore, it is likely that when firm service is not simultaneously feasible, that this may simply be a reflection of the diversity of use that was taken into account when the service was sold. However, with firm transmission service being sold on a pancaked basis by multiple transmission providers, in some instances it is possible that firm service has been oversold on specific transmission elements.

Recommendation T1: The Midwest ISO should take into account diversity of use through monthly nominations of on-peak and off-peak CFTRs in tiers 2, 3 and 4 as soon as is feasible.

The issue of maximizing the allocation of FTRs by taking into account diversity is fundamental to the initial FTR allocation meeting the FERC conditions. Therefore, the Midwest ISO should make every effort to maximize the allocation of FTRs, and going from seasonal to monthly allocations will increase the feasibility of CFTRs for tier 2, 3 and 4 allocations.

2. Technical Issue 2: Accounting for Loop Flows in the FTR Allocation Process

The FTR allocation process proposed by the Midwest ISO is based on an "estimate" of revenue adequacy. It is an estimate of revenue adequacy because in order to apply the simultaneous feasibility requirement the Midwest ISO must estimate the power flows across the Midwest ISO footprint that result from transmission transactions that are not scheduled into or through the Midwest ISO; i.e., loop flows. In addition, where it has seams agreements, the Midwest ISO must restrict FTRs by the limits to the loop flow impacts that it can have on the transmission systems of non-Midwest ISO transmission providers.

The Midwest ISO's estimates of loop flows will play a significant role in its application of the simultaneous feasibility requirement. One way to assure revenue adequacy is for the Midwest ISO to be conservative in its estimates of loop flows from and to non-MISO transmission providers. However, the impact of a conservative estimate on transmission customers will be to decrease the level of FTRs that are simultaneously feasible, resulting in higher levels of prorating. In this case, transmission customers will be faced with reduced coverage, and whenever loop flows are less than estimated, day-ahead schedules from generation sources will be greater than what is included in FTRs, resulting in greater levels of congestions costs than what is paid out to FTR holders; i.e., the Midwest ISO will run a revenue surplus. While revenue surpluses will first be used to offset overall revenue deficits and then paid back to transmission customers, this process will not necessarily ensure that those transmission customers that went un-hedged will receive the payments to cover their un-hedged congestion costs.

To more accurately reflect loop flows, the Midwest ISO proposes to update its estimate of loop flows on a monthly basis. If the estimated loop flows for the month are less than what were used in the initial allocation of FTRs, then the Midwest ISO will adjust upward the allocation of FTRs that had previously been prorated. If the estimated loop flows for the month are greater than what were used in the initial allocations, FTRs will not be adjusted downward, instead the Midwest ISO would include any inadequacies of revenues in an uplift charge applied to all holders of FTRs for that month.

In addition to updating estimates of loop flows, the Midwest ISO could selectively restrict FTRs to flowgates that would be over subscribed by full FTR allocations by issuing counter flow flowgate rights ("FGRs") to the FTR holders on those oversubscribed flowgates. Then, when loop flows don't force reduced day-ahead schedules from generators, their schedules will be fully covered by the allocated FTRs. When loop flows do force reduced day-ahead schedules and congestion cost payments within the Midwest ISO are reduced, the corresponding FTR payments would be reduced by required payments from the counter flow FGRs.

Recommendation T2: The Midwest ISO should take into account the infeasibility caused by loop flows assumed within its footprint, by issuing counter-flow FGRs that correspond to the megawatt capacities of these assumed loop flows.

The assignment of counter-flow FGRs will be in proportion to the FTR megawatt impacts on what would otherwise be over subscribed flowgates. Whenever actual loop flows decrease the revenue that the Midwest ISO can recover from a congested flowgate, the holders of the counter-flow FGRs will be allocated this revenue reduction in proportion to the megawatts counter-flow FGRs held. However, there is a cap on the direct assignment of revenue inadequacy due to loop flow that is equal to the revenue inadequacy from the loop flows corresponding to the total megawatts of assigned counter-flow FGRs. Whenever the revenue inadequacy from loop flows is less than what was assumed in the assignment of counter-flow FGRs, the payments from holders of counter flow FGRs will be reduced. This approach will automatically adjust payments to FTR holders instead of allowing the Midwest ISO to accumulate excess revenues that would be distributed back to market participants on a system-wide basis.

3. Technical Issue 3: Methods for Prorating Allocations of FTRs (Fully Prorating Point-To-Point FTRs vs. Using Counter-Flow FGRs to Offset Infeasibility on Specific Flowgates).

The Midwest ISO is proposing to prorate allocations of FTRs using a weighted least squares method. This approach will minimize the megawatt prorating of point-to-point FTRs for the Midwest ISO footprint subject to the simultaneous feasibility criteria.

If the full point-to-point FTR is prorated, the holders of prorated FTRs will have their hedges to congestion costs reduced on every transmission element involved between the generation source and their load sinks. Point-to-point FTRs can be characterized by what are called transfer distribution factors that quantify the MW impact on each transmission element of one megawatt from a specified generation source to the load sinks within the power system.[21] The congestion costs from a specified generation source to a set of load sinks can be calculated as the sum of the congestion costs associated with each transmission element times the associated transfer distribution factor times the megawatts of generation.[22] In essence, by reducing the point-to-point FTRs, the holder of the FTR is left unhedged on each transmission element by the transfer distribution factor times the megawatt amount of the reduction.

[21] Transfer distribution factors are a linear representation of the power flows in a network. If the generator is producing, for example, 100 megawatts, each of the transfer distribution factors can be multiplied by 100 to predict the megawatt impact of that generation on every transmission element within the network.

[22] Congested transmission elements are called “flowgates,” and the per megawatt congestion cost associated with a flowgate is called the “flowgate shadow price.”

In addition to discussing various methods for fully prorating point-to-point FTRs, the Midwest ISO made a proposal to the Markets Subcommittee to not fully prorate the point-to-point FTR, but instead issue the holder of the FTR a counter-flow FGR on all flowgates where the full allocation of point-to-point FTRs would exceed the security limits of the flowgate. This discussion was limited to FTRs from base-load generation sources. The Markets Subcommittee voted for a full prorating of the point-to-point FTRs from base-load generation instead of counter-flow FGRs.[23]

A revenue inadequacy associated with FTR payments occurs in the following way. When point-to-point FTRs are over allocated, it is because the megawatt impact of the allocated FTRs on certain flowgates exceeds the available capacity of those flowgates. This means that the actual flows on a flowgate will be at a lower level than the FTR impacts that were over allocated across that same flowgate. The Midwest ISO only collects the flowgate shadow price times the actual flows across any flowgate in congestion costs, but pays out in FTR revenues an amount equal to the flowgate shadow prices times the FTR megawatt impacts on flowgates. Thus, at those times when allocated FTR impacts exceed the actual flows on a congested flowgates, there is a revenue inadequacy.

When there is a revenue inadequacy, the Midwest ISO must either prorate FTR payments or collect the revenue inadequacy in an uplift charge. If all FTR payments are reduced, this is equivalent to an uplift of the revenue inadequacy in proportion to the FTR payments. As an alternative, each FTR impacting the over subscribed flowgate would have its payment for that flowgate reduced in proportion to the FTR impact on the flowgate. This is financially equivalent to what would occur if each holder of point-to-point FTRs on an over subscribed flowgate were given counter-flow FGRs in proportion to the FTR impact on the flowgate. In this case, the FTR holder would be credited for the full FTR payment, but would also owe the Midwest ISO for the amount of the counter-flow FGR held on all flowgates that are revenue inadequate. Both prorating FTR payments and owing the Midwest ISO for the amount of the counter-flow FGR would only apply when a flowgate is revenue inadequate.

Recommendation T3: In cases where the prorating of FTRs from base-load generation cannot be restored by issuing counter flow FTRs from base-load generation sources, and this prorating of FTRs results in harm to the transmission customer, the Midwest ISO should consider whether or not restoring the full point-to-point FTRs and issuing counter-flow FGRs to the transmission customer will reduce the harm to the transmission customer. If harm is reduced, then the Midwest ISO should implement this alternative.

If even only a portion of the harm to a transmission customer can be reduced without uplifting the costs, this approach is consistent with OMS FTR restoration principles.

C. Requirements to Participate in the Energy Markets

[23] When the Market Subcommittee voted for a full prorating of the point-to-point FTRs from base-load generation, it was assumed that such prorating would be minimal because it was associated with tier 1.

FERC generally agreed with the Midwest ISO's proposed requirements that generators and LSEs must either become market participants, or agree to enter into agreements with market participants, in order to participate in the energy markets.[24]

In the draft tariff, Module A, MISO has defined Market Participant as "an entity that is qualified by the Transmission Provider to submit schedules for Self-Scheduled Resources, Bilateral Transaction Schedules, Bids, Offers, hold and sell FTRs, and settle in the Energy Markets and the FTR Auction". The Market Participant is required to submit a duly executed Market Participant Application to the Transmission Provider.[25] Generation Owners and Load Serving Entities (LSEs) that do not become Market Participants but want to participate in the energy markets must enter into an agreement with a Market Participant.[26] Financial responsibility remains with the Market Participant for all Transactions in the Energy Market in which it engages regardless of for whom it has arranged to make purchases and sales.[27] Therefore, Market Participants must comply with established creditworthiness criteria as established by the Transmission Provider.

The MISO's requirements for Market Participants allow the MISO to have knowledge of all flows on the system and to identify a clear entity for settlement purposes. MISO's proposal to allow scheduling only through Market Participants gives the Transmission Provider knowledge needed for maintaining control of the system. The Market Participant requirements did not significantly change from the tariff MISO filed in ER03-1118. So OMS believes it can rely on assertions made by MISO in that proceeding. Based on those prior assertions by MISO, it is the OMS's understanding that LSEs will be able to self-schedule or use bilateral contracts to serve their load similar to the way as is done today (however changes such as, measurement of losses and congestion management will occur FERC agreed with OMS's interpretation that this should not interfere with the continued ability of market participants to engage in bilateral transactions outside of the Energy Markets to serve all or part of their load, or to continue to have the option of serving their load with their own resources.[28] It is with this understanding that the OMS supports the MISO's Market Participant language.

D. Self-Scheduled Generation & Bilateral Contracts

Under MISO's EMT, Module C, Section 39.1, Day-Ahead Schedule Procedures, and specifically Sections 39.1.2 and 39.1.3, address the rules for Self-Scheduled Resources and Day-Ahead Bilateral Transaction Schedules, respectively.

MISO tariff language provides that Market Participants may submit schedules for their Resources, in whole or in part, in the Day-Ahead Energy Market. Any generation increment not scheduled as a Self-Scheduled Resource or Bilateral Contract can be offered into the Day-Ahead Market. Subsequent to Day-Ahead, any generation increment that was not scheduled as a Self-Scheduled Resource or scheduled by the Transmission Provider/MISO in Day-Ahead Market

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[24] Midwest Independent Transmission System Operator, Inc., 105 FERC ¶61,145, (October, 2003), at P. 107
[25] Module A, Section 38.2.2
[26] Module A, Section 38.3
[27] Module A, Sections 38.2.2 and 38.3
[28] *Midwest Independent Transmission System Operator, Inc.*, 105 FERC ¶61,145, (October, 2003)

may be scheduled as a Self-Scheduled Resource or Bilateral Contract in the Real-Time Market pursuant to the procedures in Section 41.

Based on the OMS's discussion with MISO Staff, OMS is confident that Load Serving Entities will be able to continue to serve their load with same generation as is used today, if that is what the LSE chooses. The Energy Market proposed by MISO in the TEMT is strictly an energy market, with no capacity or ancillary services market, at this time. However, while the proposed Energy Market is a voluntary market, incentives exist for market participants to schedule their load Day-Ahead. For example, since FTRs settle based on the solving of the Day-Ahead market, scheduling load in the Day-Ahead market provides the best hedge against congestion costs, assuming the Real-Time schedule matches. In contrast, providing energy for a load in the Real-Time market would expose a company to a different (likely higher) level of congestion costs than would be covered by the FTRs that were settled in the Day-Ahead.

In addition, the Market Monitoring and Mitigation Measures contained in Module D require the IMM to both test and alleviate the physical or economic withholding of generation.

E. Control Area Responsibilities and Multiple Entities in one Control Area .

The OMS would like a better understanding of how control areas functions will be performed where a control area serves more than one entity. As an example, how will load forecasts be coordinated in multiple-entity control areas? The question is particularly acute where one entity is a market entity in the MISO market and another entity is not in the MISO market. It appears that the market entity would be responsible for control area functions designated to the control area, such as load forecast. This may be appropriate for market participants who are the majority of the load in the control area or where the market participant is providing transmission via network service. However, an entity may not be either the majority of the load in the control area or the provider of transmission service for the non-market participant. Thus, the situation exposes the MISO market participant to situations and costs that are beyond their control. The OMS urges MISO to provide additional clarity on this issue.

The OMS is aware that the split of control area functions between MISO and the control area operator is still being resolved and that a model addressing these issues is currently being worked on with the North American Electric Reliability Counsel (NERC) by MISO.

F. Security-Constrained Unit Commitment and Security Constrained Economic Dispatch in the Day-Ahead Market

Section 39.2.9, Day-Ahead Energy Market Process, in Module C of MISO TEMT, provides the specific language for how the Transmission Provider/MISO will clear the Day-Ahead Energy Market using both the Security-Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) to simultaneously: (i) clear offers and bids for each Hour of the next operating day to yield day-ahead schedules; (ii) efficiently allocate transmission capacity to day-ahead schedules by resolving transmission constraints; and (iii) commit available resources at least-cost to meet the energy and congestion management requirements throughout the operating day.

For purposes of clearing the day-ahead energy market MISO continues to require each control area operator provide MISO with an hourly forecast of its load requirements by 9 am EST on the day before the operating day consistent with the provisions of Section 38.5.5. The OMS notes that MISO was encouraged by the FERC's October 29, 2003 Order to move the bidding deadline to 11 am EST as soon as possible.[29] OMS supports moving to a later deadline. MISO should prove it can solve day-ahead schedules using the SCUC and SCED by the scheduled deadline. OMS does consider the MISO footprint to be a large footprint that may require a more significant level of time than other markets, at least in the short term.

The OMS supports MISO's use of both the SCUC and SCED which will allow for the lowest cost resources (including start-up costs) to be scheduled while considering the operational ability of generating units available and any transmission constraints. It appears to be the best optimization of cost and operations, based on generation that schedules in the day-ahead market.

G. Access to Market Data by State Commissions

In its September 15 comments, the OMS noted that the ability of State Commissions to fully satisfy their statutory obligations regarding the monitoring of the competitiveness of wholesale electric markets and protecting retail customers from the exercise of market power hinges on access to market participant transaction data and information in the regional energy markets administered by the MISO.[30]

The OMS also intends to assume other duties including, but not limited to, involvement with the MISO's regional planning and facilitation of resource implementation as delineated in the FERC's White Paper (the Standard Market Design and FERC Orders) that will require State Commission access to a broad range of confidential information. Section 38.7.3 of MISO's July 25 TEMT contained language recognizing this need and would have effectively increased the availability of information to state regulators upon request. However, the language in 38.7.3 limited the State Commissions' access to data that was collected by the MISO. As the OMS pointed out in its September 15 comments, much of the data that will allow the State Commissions to meet their statutory obligations will be collected and held by the Market Monitor.

Prior to the release of its February 11 draft of the TEMT, the Midwest ISO engaged in several discussions with the OMS Market Monitoring and Mitigation Working Group regarding access to confidential data by State Commissions. MISO's effort to accommodate the needs of the State Commissions is to be commended. While MISO's current TEMT draft is a large step in the right direction toward: a) meeting the needs of the State Commissions to access data while balancing the MISO's obligation to protect the legitimate interests of market participants, b) ensuring comprehensive monitoring of the relevant markets, c) prevention of conduct that is either inconsistent or abusive, or where necessary d) effective mitigation of abusive practices by market participants, some aspects of the draft TEMT need additional clarification and refinement to achieve the balance.

[29] 105 FERC ¶ 61,145 at p. 20.
[30] OMS' September 15 Comments, at 17

H. Western Seams Issue

The OMS is hopeful that the Western Seams issue (half of MAPP region in the MISO market and half of MAPP region not in the MISO market) can be resolved in the short-term, prior to implementation of the market. MISO must work to resolve the seams issues addressed in the Energy Market Tariff prior to implementing the market to ensure adequate reliability in the MAPP region and for purposes of the entire MISO footprint. A conference addressing the seams issue was held on March 2, 2004 by MISO in Bloomington, Minnesota.

I. Market Monitoring and Mitigation Mechanisms

1. Market Monitoring

The OMS believes the MISO Tariff places the correct emphasis on the need for effective monitoring of the markets with the aspiration of preventing market abuse, gaming, and exploitation of market design flaws. However, the OMS recommends that both the MISO and the Independent Market Monitor (IMM) incorporate into the TEMT, where appropriate, the following concepts for FERC approval.

a. The IMM Should Have Access to Fuel Information

To facilitate its efforts to monitor the electricity market, nothing in the MISO Tariff should serve as an impediment to the IMM's ability to work with the FERC to monitor fuel markets as inputs into the production of electricity. As an example, some combination gas and electric utilities may be in a position to engage in anticompetitive practices in either the gas or electricity markets through sales of gas commodity and / or transportation to merchant power plants and independent transmission companies. Further, there are "combinations" of natural gas companies that engage in gas procurement for their respective Local Distribution Companies as well as other unaffiliated clients through the use of agency contracts. In both of these instances, there is a potential for market manipulation that can be minimized or eliminated through the IMM having access to fuel market information. Such access should result in increased price transparency and the reduction of the likelihood of market manipulation that may result in damage to end-users.

While the monitoring of natural gas markets could be considered to be outside the IMM's scope of authority, the OMS believes that electricity markets would benefit from FERC enlisting the assistance of the IMM in its monitoring of the fuel markets as inputs into electricity production. Any mitigation would remain a matter for the FERC.

b. The IMM Should Be Authorized to Monitor Intra-Company Transactions

Given that multi-state vertically integrated utilities (including those that have fuel subsidiaries) and combination electric and gas utilities may have opportunities to engage in affiliate transactions that are anticompetitive or otherwise disruptive to both the wholesale market and individual states' retail markets, the IMM should be authorized to monitor intra-company transactions. In particular, the IMM should be able to review transactions between operating companies of multi-state holding companies that have operations in states that permit retail competition as well as operating in some states that are traditionally regulated. For those utilities that operate in multiple RTOs, especially in advance of establishment of "Joint and Common Markets," there is a need to assure that the IMM is able to identify transactions where these companies are engaged in conduct that improperly exploits market design differences. In these situations, the IMM should recommend a solution that eliminates such behavior, as well as report any illegal or anticompetitive behavior to the appropriate authorities such as FERC, FTC or State Commission.

c. The IMM Should Be Authorized, on a Case-By-Case Basis or for Specific Issues, to Review Market Power Ramifications of Energy Company Mergers

Mergers and acquisitions have potentially profound implications for regional energy markets if the merged companies operate under different regimes. One concern is for trade among affiliated companies where one is a member of an RTO and another affiliate operates in areas that do not have an established RTO. Trade among affiliated operating companies in this circumstance poses real and perceived risks to the integrity of the markets. Another potential risk occurs in situations where operating companies are in more than one RTO and there is no Joint and Common Market among these RTOs. In these examples, as well as other situations involving affiliated operating companies, the Market Monitor should be authorized to assist both the FERC and State Commissions, on a case by case basis or with specific issues to assess wholesale and retail market power implications as well as other market ramifications that mergers and acquisitions may entail.

d. The IMM Should Be Authorized to Review the Commercial Implications of Regional Reliability Council Actions

Currently, RTOs and regional reliability councils do not share the same boundaries. As a consequence, the potential exists for reliability considerations directed by regional reliability councils to have unintended reliability and commercial consequences for the markets administered by the RTO. In the event that such a circumstance would arise, the OMS recommends that the IMM be authorized to assess any potential for behavior that may be disruptive to the markets. The IMM would not be asked to express an opinion on the reliability implications.

e. The IMM Should Be Authorized to Review Inter-RTO Agreements and Agreements with Transmission Owning Entities that Are Unaffiliated with RTOs, Regarding Operating and Planning

To provide greater assurance that differences in operations and planning among RTOs and transmission-owning utilities that are not affiliated with RTOs, do not create opportunities for abusive conduct – including gaming and unfair exploitation of differences - the IMM should be authorized to review those agreements and subsequent implementation inter-RTO Agreements and agreements with entities that are unaffiliated with an RTO. For example, the Independent Market Monitor for the MISO should have shared authority with the PJM's internal Market Monitor to assess the operations of entities such as Commonwealth Edison's and American Electric Power Company's utilization of the transmission ties that are within the MISO's geographic boundaries.

2. OMS Comments Regarding Market Mitigation

The OMS acknowledges that the TEMT contemplates a reassessment of various thresholds and reference levels (e.g., Section 63.1.4) to balance the protection for consumers and the appropriate functions of the market, these are incipient markets that may require closer scrutiny in the near term and modifications to market rules, standards and procedures. Accordingly, the OMS expects to be engaged with parties such as the Market Monitor, the MISO, the FERC, market participants and stakeholders in reviewing the appropriateness of this and other Market Monitoring practices.

The OMS may request additional protections in conjunction with other components of the MISO Tariff to prevent unintended and inequitable outcomes. The OMS recognizes, for instance, the concern for consumers that are located in persistent "load pockets." It may be that the operation of various aspects of the LMP markets, such as the implementation of Financial Transmission Rights, might result in such unintended consequences that will need to be ameliorated by more assertive market monitoring and mitigation.

J. Performance Metrics

With regards to background, MISO's Progress Report on the Midwest Market Initiative ("Report"), which was filed at FERC for informational purposes on January 23, 2004, provides the following "Readiness Progress Review":

1). Progress Since Last Report

The Midwest ISO has published on its website Metric Interpretive Guidance documents for many of the metrics. These documents give the stakeholders a reference regarding how the Midwest ISO plans on meeting each metric. PA Consulting introduced their firm to the Advisory Committee in November. A high-level plan related to the metrics was presented to the Advisory Committee by PA Consulting at the January Advisory Committee meeting. PA Consulting will begin providing the Board of Directors and Advisory Committee status reports on the performance metrics beginning in January.

2). Progress Expected in Next 120 Days

The Midwest ISO will continue the implementation process to meet each metric. As each metric is achieved, the Midwest ISO will forward to PA Consulting the information associated with that metric so that PA can start its independent verification process. As metrics are independently verified, PA will report the status to the Board of Directors each month. The Midwest ISO will forward these reports to the Advisory Committee.

PA Consulting, in its Update on Activities to Date ("January Update") that was presented to the Midwest ISO Advisory Committee on January 14, 2004, states,

> "Based on our experience with other market start-ups, we are familiar with several different processes for verifying the completion of specific Readiness Metrics. The process for PA's verification of the completion of each Metric will be specified in a Verification Plan. Although the Verification Plan describes the approach that we will apply to give our independent assurance that each and every Readiness Metric has been completed, the Verification Plan will build on the MISO's own metrics-related process, including Metric Interpretive Guidance and Completion Review Documents.
>
> The Verification Plan is currently in ongoing development and is expected to be completed by the end of January 2004. Once complete, the Verification Plan will be relatively static, but changes may be made, if appropriate, and a revised Verification Plan would be issued."

PA's January Update also states:

> For some metrics, more than one verification process may be possible. In such circumstances, a choice must be made taking into account a number of considerations, including:
>
> - the nature and technical content of the Readiness Metric in question
> - the level of assurance that should be provided to the constituents of the readiness review
> - budget implications of choosing a more thorough or detailed verification process.
>
> For some metrics, it may be appropriate to combine elements of the alternative possible approaches. These choices among alternative verification approaches are being made as the Verification Plan is developed.[31]

In its February 18, 2004 presentation to the Midwest ISO Advisory Committee regarding Readiness Advisor's Verification Plan Release No. 1 ("February Update"), PA Consulting states:

> About Release No. 1:
>
> Verification approach for each metric depends on the MIG and many of these are still in discussion and finalization. Accordingly, Release No. 1 indicates that the verification approach for many individual metrics is still to be determined (TBD). To conserve scarce resources – at least until a more complete picture of the overall need for verification activities comes into clearer focus – the RA has been instructed by the MISO to include only the minimal set of activities that could reasonably establish that the

[31] January Update, page 15.

metric has been met. A deeper review is possible, as warranted, after consultation with the MISO.

PA Consulting's Monthly Formal Status Report – February 2004 states that zero (0) performance metrics have been "completed and verified"; zero (0) performance metrics are "currently being verified"; and that 123 performance metrics are "not yet completed".

As noted above, PA Consulting's January Update states that the Verification plan "is expected to be completed by the end of January 2004." MISO's January 23, 2004 Report indicates that PA Consulting will follow an independent verification process. PA Consulting's February Update, however, states that MISO is instructing PA Consulting "to include only the minimal set of activities that could reasonably establish that the metric has been met."

Accordingly, the OMS offers the following recommendations. Specifically, that the Verification Plan should be finalized in time to enable PA Consulting to provide the OMS with thorough and accurate measures of MISO's readiness to properly implement Day 2 markets on December 1, 2004. On or before March 31, 2004, MISO should state its expectations regarding 1) the overall need for verification activities; and 2) the date of the (initial) finalization of the Verification Plan.

The OMS also recommends that MISO clarify who is accountable for the provisions of the Verification Plan that PA Consulting will use to assess whether or not MISO has met each "performance metric". MISO should explain its expected role of stakeholders, including the OMS, in developing the Verification Plan. For example, will MISO seek OMS review and/or Advisory Committee approval of the Verification Plan?

K. Resource Adequacy and Capacity Markets

On January 6, 2004 the MISO Market Subcommittee rejected a resource adequacy proposal initiated by MISO Staff as an interim measure to fill the gap left by the absence of a resource adequacy and capacity market in the design for the start-up of an energy market under the MISO TEMT. The members of the Market Subcommittee passed a motion to "reactivate" the MISO Supply Adequacy Working Group ("SAWG") "to work together with the OMS States on a more appropriate solution." As a consequence, the former charter establishing the SAWG was redrafted to include a formal "interface" with the OMS Resource Adequacy and Capacity Markets Working Group (OMS RAWG). Indeed, the FERC has sent signals to the Organization of MISO States that they expect the OMS to "complete its work in developing a Resource Adequacy Plan for the day-ahead market." Given these circumstances, the OMS RAWG understands that any resource adequacy provision of the TEMT filed on March 31, 2004 is an interim provision.

Through its RAWG, the OMS has taken a leadership role in developing a long-term resource adequacy plan ("the Plan"). A set of OMS principles for developing and implementing resource adequacy requirements and a MISO Capacity Market ("OMS Principles") was developed by the OMS RAWG and includes suggestions and edits provided by the MISO SAWG. The OMS Board of Directors accepted the OMS Principles on March 12, 2004. These principles continue to be considered by the MISO SAWG and the OMS RAWG in their joint discussions and negotiations to develop a resource adequacy plan for the MISO Day Ahead Market that gives full consideration to a regional capacity supply and demand balance so that provisions are in place at the time of need. To that end, the OMS Principles recommend that MISO, in determining region-wide resource adequacy requirements and designing a capacity market:

1. Provide resource suppliers an opportunity to recover a portion of their investment costs, as part of an available revenue stream;

2. Design a capacity market that proactively moves toward a larger regional market while respecting existing reserve sharing agreements and neighboring systems' capacity market requirements while operating under the scrutiny of the MISO Independent Market Monitor;

3. Base reserve margin and capacity market requirements on the following three factors:

    a. Unforced capacity;
    b. Regional Reliability Organization (RRO) and existing State planning and operating reserve requirements; and
    c. Reserve obligations based on an aggregate of individual RRO assessments of loss-of-load expectation of one day in ten years.

4. Set planning horizon and commitment periods to be sufficiently forward looking to allow consideration of new capacity additions (of all fuel types and technologies) as resource options, while also providing mechanisms that allow the participation of demand response and load reduction;

5. Set planning and operating capacity reserve responsibilities in advance and allocate them fairly and equitably to all Load Serving Entities on a load-ratio basis;

6. Allow dispatchable demand response, verifiable load reduction and renewable resources to participate in the capacity market;

7. Allow LSEs to meet their capacity reserve responsibilities through such mechanism as:
    a. Self-supply,
    b. Bilateral contracts with suppliers,
    c. Spot market capacity offerings,
    d. Demand response or load reduction,
    e. Forward capacity assessment and markets, or
    f. Any combination of all of the above.

8. Require capacity certification/accreditation/ratings test procedures and deliverability verification to certify a capacity resource that is being relied upon to meet MISO capacity requirements for a predetermined time period (seasonal, monthly);

9. Allow capacity transactions with generators internal and external to MISO by addressing the following:
    a. Certified capacity provided into the MISO market internally;
    b. Capacity provided by a generator located in the MISO area to an external area under a reserve-sharing or other agreement;
    c. Capacity provided by a generator located in the MISO area to an external area as a resource participant in the external area's capacity market;
    d. Capacity provided into the MISO capacity market by a generator located outside the MISO area under a reserve-sharing or other agreement;
    e. Capacity provided into the MISO capacity market by a generator located outside the MISO area as a resource participant in the MISO's capacity market; and
    f. Issues of non-recallability either by MISO or by the operator of the external area.

10. Require an annual forward-looking report to include a long-term MISO load forecast and a supply plan for meeting capacity and reserve requirements with accredited and deliverable capacity;

11. Each entity responsible for serving MISO Load should be audited periodically to ensure that accredited and deliverable capacity sufficient to meet peak load plus the applicable reserve requirement was in place at all times during the previous period; and

12. Assess an "obligation" payment for audited deficiencies in maintaining reserve requirements in an amount sufficient to deter risking future inadequate reserves.

The OMS offers the following observations: Resource adequacy for electric suppliers means having enough generating capability to serve all load regardless of probable contingencies such as unforeseen outages or loads that turn out to be larger than expected. Some utilities have accomplished resource adequacy through regional pooling of reserve generation, thus maintaining adequate reserves while minimizing costs to individual utilities. Utilities in most regions share two types of generating reserves, often referred to as operating reserves and planning reserves.

Operating reserves are derived from generators that are either spinning or able to come on line within a prescribed time. Requirements for operating reserves are set by Regional Reliability Organizations ("RROs") at levels deemed necessary to prevent real-time imbalances between supply and demand.

Planning reserves are an additional margin of generating capability beyond what is immediately needed for operating reserves. Difficulties in forecasting load, unexpected generator outages and long lead times for new construction all contribute to the likelihood that electric supply shortages could occur. Planning reserves provide insurance against the risk of insufficient operating reserves, which could result in loss of load, unreliable electric service or, as a worse case, system collapse. Historically, RROs have performed studies to set planning reserve requirements at a level typically resulting in a loss of load probability of one day in ten years.

In addition to reliability of electric service, planning reserves are further necessary for price stability in energy and capacity markets. Electric supply can be considered inelastic over the short term because it can be difficult for markets to respond quickly to unexpected shortages. Absent adequate planning reserves, prolonged periods of volatile market prices are likely.

Planning reserve requirements help to encourage diversity among generation fuels. Shorter construction times, less capital investment and environmental factors have combined to make natural gas the fuel of choice in competitive electric markets. Natural gas prices are already reflecting the increased demand. Requirements for maintaining long-term planning reserve margins help dampen market fluctuations so that projects that might otherwise respond to supply urgency are more likely selected according to total lifetime costs.

Planning reserve requirements encourage capacity markets. Bilateral contracts for generating capacity occur naturally under minimum capacity requirements, regardless whether auctions or other market-structures are enacted. The resulting recovery of fixed generator costs through fixed capacity charges reduces financial risk for generators and enhances market price signals. On February 26, 2004, a draft of the TEMT containing supply adequacy tariff language (Module E) was released to OMS members and other stakeholders. Module E appears to be substantially the same, at least in principle, as the Resource Adequacy Proposal rejected by the MISO Market Subcommittee.

Module E

The OMS thanks the Midwest ISO for recognizing the need for States' direct involvement in the Resource Adequacy efforts, as well as for attempting to recognize the differences imposed by separate Regional Reliability Organization reserve requirements in MAPP, MAIN and ECAR. Given the interim nature of Module E as released by MISO on February 26th and in light of the OMS Principles, the OMS suggests that Module E be revised to address the following issues:

1) It is not clear from the Tariff language that the Resource Adequacy provisions will do no financial or any other harm to native load or any other customers.

2) The Module E language fails to recognize either the potential market-to-market seams with PJM in portions of MISO in the East or the market-to-non-market seams in the MAPP portions of MISO in the West. It is not clear, for example, that the language in Section 69.2, "DNR Must Offer Requirement," is not in conflict with Section 68.1.1, "Compliance with Regional Reliability Organizations." Section 69.2 should be deleted, or in the alternative, only require the pro rata portions of Designated Network Resources to be scheduled in the Day Ahead Market that are required to serve load for the following day. The following sentence should also be deleted or modified to be consistent with Section 68.1.1: "At its sole discretion, Transmission

Provider may curtail export transaction schedules sourced at a DNR or from the Spot Market during a declared Energy Emergency Alert."

3) Alternative Capacity Resource section needs to be clarified to include mechanisms that allow the participation of demand response and load reduction options in addition to the interruptible demand option.

4) It is not clear whether renewable resources will be included as designated network resources.

5) The tariff language discusses that compliance will be evaluated but it does not discuss whether there are any consequences for non-compliance with the standards.

6) The language does not require any verification or tests for certifying capacity ratings.

7) It is not clear whether there are any reporting requirements relating to long-term forward-looking system requirements.

L. Business Practices Manuals

Based on our discussion with the MISO, the Business Practices Manuals will not be filed with the FERC to allow for the most flexibility. The OMS' concern is to make sure the information necessary to determine the appropriate rates and to facilitate the resolution of dispute is on file with the FERC. To the extent these details are in the Business Practices Manuals, they must be reflected in the tariff, or somehow on file with the FERC.

V. CONCLUSION

The OMS believes that the MISO's TEMT will prove to be a cornerstone in the establishment of a competitive wholesale electricity market in the Midwest. The OMS is encouraged by the direction that the TEMT is headed. However, as the OMS has illustrated above, there are key issues that must be addressed for this objective to be achieved. Accordingly, the OMS urges MISO to implement the recommendations made in Section III of these comments. To that end, the OMS stands ready to assist MISO in its efforts to implement and fine-tune the TEMT and ultimately establish a competitive Midwest electricity market.

The Organization of MISO States submits these comments since a majority of the members have agreed to generally support them. The following members generally support these comments, but reserve the right to file clarifying comments or minority reports on their own regarding the issues discussed in these comments:

North Dakota Public Service Commission
Missouri Public Service Commission
Michigan Public Service Commission
Wisconsin Public Service Commission
Iowa Utilities Board

Illinois Commerce Commission
Montana Public Service Commission
Pennsylvania Public Utility Commission
Minnesota Public Utilities Commission
Indiana Utility Regulatory Commission
Kentucky Public Service Commission

For procedural reasons, these members are not able to express a formal position at this time:

Nebraska Power Review Board
Ohio Public Utilities Commission

Members not participating in these comments are:

Manitoba Public Utilities Board
South Dakota Public Utilities Commission

The Minnesota Department of Commerce, as an associate member of the OMS, supports these comments and participated in the preparing of these comments.

Respectfully submitted,

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