111 FERC ¶ 61,043
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

Midwest Independent Transmission System Operator, Inc.	Docket Nos. ER04-691-012 ER04-691-016 ER04-691-017
Public Utilities With Grandfathered Agreements in the Midwest ISO Region	Docket No. EL04-104-011 EL04-104-015 EL04-104-016

ORDER ON REHEARING AND COMPLIANCE FILINGS

(Issued April 15, 2005)

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1. In an order dated August 6, 2004, the Commission approved the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) proposed Transmission and Energy Markets Tariff (TEMT), under which the Midwest ISO has initiated Day 2 operations in its 15-state region.[1] The Midwest ISO's Day 2 operations include, among other things, day-ahead and real-time energy markets and a financial transmission rights (FTR) market for transmission capacity. The TEMT II Order required the Midwest ISO to make an assortment of compliance filings to implement various Commission directives. The Commission accepted the Midwest ISO's first two such filings on December 20, 2004, subject to further modifications.[2]

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[1] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (TEMT II Order), *order on reh'g*, 109 FERC ¶ 61,157 (2004) (TEMT II Rehearing Order). The TEMT contemplates that all services provided pursuant to its terms and conditions will be provided by a Transmission Provider. In turn, the TEMT defines "Transmission Provider" as the Midwest ISO or any successor organization. *See* Module A, section 1.320, Original Sheet No. 133. For clarity, we will refer to the Midwest ISO wherever the TEMT refers to the Transmission Provider.

[2] *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,285 (2004) (Compliance Order I).

2. Today's order will address the requests for rehearing of the TEMT II Rehearing order, as well as the Midwest ISO's and the Independent Market Monitor's (IMM) respective January 7, 2005 filings to comply with that order. A concurrent order will address the requests for rehearing of Compliance Order I, as well as the Midwest ISO's and the IMM's filings to comply with that order. Our order benefits customers because it clarifies important questions regarding procedures under the Day 2 energy markets.

I. Background

3. The TEMT II Order accepted and suspended the proposed TEMT and permitted it to become effective March 1, 2005, subject to conditions and further orders. The Commission also accepted certain tariff sheets (pertaining to FTRs) to be effective on August 6, 2004, subject to conditions and further order. In order to address the Midwest ISO's unique features, such as the fact that it lacks experience operating as a single power pool and has only a short period of experience operating under a single reliability framework, the Commission ordered the Midwest ISO to implement additional safeguards to ensure additional protections for wholesale customers during startup and transition to fully-functioning Day 2 energy markets. In an order issued February 17, 2005, the Commission granted the Midwest ISO's motion to change the effective date of the TEMT to April 1, 2005.[3]

4. The Commission has accepted, subject to modification, the Midwest ISO's first three filings to comply with the TEMT II Order. Compliance Order I addressed the first two of those filings, which, *inter alia*: (1) proposed to revise the TEMT to eliminate Michigan-specific energy imbalance provisions; (2) developed tariff language for market startup safeguards; (3) modified the FTR allocation process; (4) made new proposals for automatic market power mitigation and control area mitigation; and (5) revised various other aspects of the TEMT. As described *infra*, the Midwest ISO was required to make further filings to comply with Compliance Order I.

5. Compliance Order II,[4] which was issued on January 21, 2005, accepted: (1) proposed rules providing for corrective measures in the event of temporary inability to calculate accurate market prices; (2) a proposed plan for cutover to decentralized power system operations in the event of a serious failure of the Day 2 energy market

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[3] *Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,169 (2005).

[4] *Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,049 (2005) (Compliance Order II).

operations; (3) an update on the Midwest ISO's effort to adjust the day-ahead energy trading deadline from 0900 EST to 1100 EST, and (4) a Readiness Advisor Verification Plan. The Midwest ISO was required to make further filings to comply with Compliance Order II, and those filings will be addressed in a future order.

II. Requests for Rehearing of TEMT II Rehearing Order and Responsive Pleadings

6. Eight parties filed requests for rehearing or clarification of the TEMT II Rehearing Order: (1) Basin Electric Power Cooperative and East River Power Cooperative, Inc. (collectively, Basin Cooperatives); (2) Cinergy Services, Inc. (Cinergy); (3) Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (collectively, Constellation); (4) FirstEnergy Service Company (FirstEnergy); (5) Midwest Municipal Transmission Group; (6) Midwest Stand-Alone Transmission Group (Midwest SATCs);[5] (7) Midwest Transmission-Dependent Utilities (Midwest TDUs);[6] and (8) Wisconsin Electric Power Company (WEPCO). Otter Tail Power Company (Otter Tail) filed a response to Basin Cooperatives' request for rehearing.

7. Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier) filed a motion to lodge a 1997 Commission order in the record of this proceeding. Hoosier states that Cinergy's request for rehearing included an answer to Hoosier's protest of a Midwest ISO compliance filing. According to Hoosier, Cinergy stated that Hoosier's protest pointed out that the Midwest ISO's filing failed to comply with the Commission's directive that certain GFAs could be carved out of the Midwest ISO's energy markets. Hoosier states that Cinergy also noted Hoosier's concern that subjecting Hoosier to energy imbalance costs from Midwest ISO markets could subject Hoosier to trapped costs. Hoosier states that Cinergy argued that, in an analogous situation, the Commission has rejected the

[5] The Midwest SATCs are: American Transmission Company LLC; GridAmerica LLC; International Transmission Company; and Michigan Electric Transmission Company, LLC.

[6] The Midwest TDUs are: Great Lakes Utilities; Indiana Municipal Power Agency; Lincoln Electric System; Madison Gas and Electric Company; Midwest Municipal Transmission Group; Missouri Joint Municipal Electric Utility Commission; Missouri River Energy Services; Southern Minnesota Municipal Power Agency; and Upper Peninsula Transmission Dependent Utilities.

notion that there can be a distinction between a cooperative and its member-customers, citing *Wolverine Power Supply Cooperative, Inc.*, 94 FERC ¶ 61,178 (2001). Hoosier argues that Cinergy's reference fails to take into account that Wolverine is a jurisdictional public utility, whereas Hoosier is not. Hoosier therefore asks to lodge the order in which the Commission initially accepted Wolverine's rates for filing.

III. The Midwest ISO's and the IMM's Compliance Filings

A. The Midwest ISO's Compliance Filing

8. On January 7, 2005, the Midwest ISO made a compliance filing as required by the TEMT II Rehearing Order. The compliance filing proposes revisions to the TEMT that clarify FTR procedures, revenue credits from locational marginal pricing (LMP) markets, the definitions of demand response resources, the must-offer requirement, credit policy, various definitions in Module A, the deadlines for submission of firm and non-firm schedules, various clarifications in Module C and responses to questions raised by Cinergy.

9. Notice of the Midwest ISO's compliance filing was published in the *Federal Register*, 70 Fed. Reg. 3,696 (2005), with interventions and protests due on or before January 28, 2005. Manitoba Hydro filed a protest, to which the Midwest ISO filed an answer.

B. The IMM's Compliance Filing

10. On January 7, 2005 the IMM made a compliance filing in response to requirements of the TEMT II Rehearing Order. The compliance filing details the IMM's description of a safety-net plan for day-ahead mitigation, to be implemented in place of automated mitigation or expedited manual mitigation, details a plan and timeline for implementation of the proposed day-ahead mitigation, and explains a plan to monitor for the inefficient scheduling, i.e., over-scheduling in the day-ahead market to monetize the Narrow Constrained Area (NCA) expanded congestion cost hedge and to monitor for aggregate day-ahead schedules that exceed the import capability in NCAs.

11. Notice of the IMM's compliance filing was published in the *Federal Register*, 70 Fed. Reg. 3,695 (2004), with interventions and protests due on or before January 28, 2005. Detroit Edison Company (Detroit Edison) filed a protest. The Coalition of Midwest Transmission Customers (Coalition MTC) and the Midwest TDUs jointly filed a protest.

IV. Discussion

A. Procedural Matters

12. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2004), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the Midwest ISO's answer because it has provided information that assisted us in our decision-making process.

13. The Midwest TDUs argue in their request for rehearing that the Commission erred in rejecting their response to the IMM's September 13, 2004 request for clarification. They state that the Commission found that the IMM's filing was not a request for rehearing, yet the Commission rejected the Midwest TDU's answer thereto as a prohibited answer to a request for rehearing. The Midwest TDUs state that Rule 713(d)(1) of the Commission's Rules of Practice and Procedure do not prohibit their answer, and that Rule 213(a)(2) and (3) permit it.

14. The Commission has revisited the Midwest TDUs' September 28, 2004 answer to the IMM's request for clarification, and we are not persuaded to change our decision not to accept it. First, as described below, we continue to find that the IMM presents stronger arguments than the Midwest TDUs with regard to automated and expedited mitigation, which was the subject of the Midwest TDUs' September 28 filing; had we accepted the Midwest TDUs' filing, our conclusions would have been the same. Second, the Midwest TDUs' Request for Rehearing of the TEMT II Rehearing Order presents the same arguments as the September 28 answer, and we will take them up in this order. We do not, therefore, believe that our rejection of the earlier pleading will harm the Midwest TDUs.

15. We will deny Hoosier's motion to lodge *Wolverine Power Supply Cooperative, Inc*.[7] Hoosier's motion attempts to refute statements in Cinergy's request for rehearing, and is therefore more akin to an impermissible response to a rehearing request than a motion. In addition, parties need not lodge Commission orders in subsequent Commission proceedings. Parties may cite the orders, and we will consider the orders, without the formality of lodging.[8]

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[7] 81 FERC ¶ 61,369 (1997).

[8] *See Northeast Utilities Service Company*, 58 FERC ¶ 61,069 at 61,177 (1992).

B. <u>Readiness and Market Startup Safeguards</u>

1. <u>Transitional Safeguards for FTR Allocation</u>

a. <u>Background</u>

16. The Commission approved an expanded congestion cost hedge for five years to entities located in an NCA designated as such within six months from the start of the market.[9] The hedge will hold entities in NCAs harmless from congestion costs for their existing firm transmission contracts. Given the Midwest ISO's flexible FTR nomination process, which could result in an oversubscription of the most congested lines, and hence result in some pro-rationing of nominated FTRs for entities that could be highly dependent on existing firm transmission to generation resources outside the load pocket, the Commission found the expanded congestion hedge to be reasonable as a transition mechanism.[10] Only FTRs from external sources are eligible for expanded cost coverage, which will guarantee that the net congestion cost for these external sources is zero. If the FTRs for these external resources are insufficient to fully cover congestion charges, the expanded congestion cost hedge requires that the Midwest ISO will make up the deficit through an uplift charge.[11]

17. In the TEMT II Rehearing Order, the Commission redefined the congestion cost coverage for external network resources to the NCA, rather than the original definition of resources external to the control area and the state, and clarified that entities eligible for the congestion cost coverage must nominate the total FTRs associated with their forecast peak load.

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[9] *See* TEMT II Order at P 73-77.

[10] *Id.* at P 90 (citing *New England Power Pool and ISO New England, Inc.*, 101 FERC ¶ 61,344 (2002), which supported the use of transition mechanisms for pre-existing load pockets).

[11] *Id.* at P 92.

b. Requests for Rehearing

18. FirstEnergy states that the TEMT II Rehearing Order will exacerbate the problem of the full congestion cost protection by expanding it to imports from resources within the same state as the NCA. If the congestion cost protection scheme ultimately is permitted to remain in effect, which FirstEnergy opposes, it should be exceedingly narrow in scope and not include congestion cost protection for imports from within the same state.

19. FirstEnergy states that the TEMT II Order's limitation of the congestion cost hedge to congestion costs associated with imports into NCAs from resources external to the NCA control area to the state where the NCA is located minimize the adverse consequences associated with the full congestion cost hedge, including cost shifts, subsidization, market distortion, and discrimination against other market participants. FirstEnergy argues, however, that the TEMT II Rehearing Order removed one of the two limitations by clarifying that the congestion cost coverage for external resources is for such resources that are external to the NCA, rather than requiring such resources to be external to the control area and the state, as the TEMT II Order did. As a result, FirstEnergy says, rather than minimize the potential harm of its congestion cost protection scheme, the TEMT II Rehearing Order heightened the opportunity for injury to the market and other market participants. Thus, all of the arguments that FirstEnergy set forth in its September 7 Request for Rehearing, opposing full congestion cost protection for market participants in NCAs, apply with equal force to the Commission's expanded application of the scheme to external resources within the same state as the NCA. FirstEnergy argues that by giving more resources, and thus more transactions, a complete hedge against congestion costs, the Commission has made it more likely that significant cost shifts will occur, market participants will receive service at prices that are discriminatory and preferential, and that new investment where it is needed most (i.e., in and around NCAs) will continue to stagnate.

c. Discussion

20. The effect of the TEMT II Rehearing Order is that one Wisconsin-Upper Michigan System (WUMS) entity with a resource outside WUMS and inside the State of Wisconsin will receive coverage for congestion cost relief and several resources inside the NCA that serve load outside the NCA will no longer receive congestion cost relief.[12] We do not consider this result a substantive, adverse modification as FirstEnergy claims. Furthermore, we do not agree with FirstEnergy that the TEMT II Rehearing Order expands congestion cost protection and heightens the opportunity for injury to the market

[12] *See* TEMT II Rehearing Order at P 41.

since the revised relief expands the congestion relief to one new resource while reducing the congestion relief to several resources. For these reasons, we deny FirstEnergy's request for rehearing.

C. Other Issues Related to the FTR Allocation Process

1. FTR Eligibility for Holders of Network Service Contracts with Short-Term Network Resource Designations

a. Background

21. The TEMT II Order affirmed that long-term existing rights (of one year or more) have priority over short-term or seasonal rights in the annual FTR allocation process, reflecting the reasonable expectation of long-term customers that they retain their transmission service.[13] The TEMT II Rehearing Order clarified that seasonal network resources with annual network service should only be eligible for seasonal (or monthly) FTRs corresponding to the season (or months) in which the resource is dispatched historically.[14]

b. Requests for Rehearing

22. Constellation states that the TEMT II Rehearing Order noted Constellation's request for clarification, or alternatively rehearing, concerning the eligibility for FTR allocation to network service customers that relied on network resources with durations of less than one year. The Commission noted that others had raised similar concerns, including the Organization of MISO States's (OMS) request that the Commission sever the concept of long-term transmission service from the concept of annual designation of network resources, and expand the concept of long-term existing transmission rights to include monthly or seasonal designated resources.[15] Constellation states that the Commission noted OMS's concern that facing the risks of purchasing congestion hedges on a year-to-year or month-to-month basis will penalize load-serving entities that are more dependent on generation contracts to serve their loads.[16]

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[13] *See* TEMT II Order at P 182.

[14] *See* TEMT II Rehearing Order at P 157.

[15] *Id.* at P 152-53.

[16] *Id.*

23. Constellation states that the Midwest ISO may be interpreting the Commission's clarification that network resources with less than one year's duration are eligible for FTR awards only for 2005 FTR awards, and thereafter, the Midwest ISO plans to reinstate restrictions that would deny FTRs to Constellation and other long-term network customers because they rely on network resources with durations of less than one year. Constellation seeks clarification that the Commission did not intend to restrict its ability to rely on network resources of less than one year's duration to the 2005 FTR awards.

24. According to Constellation, the Commission correctly described and did not reject arguments that network service is always long-term service, and that relying on network resources of less than one year is a common and efficient practice that does not change that service into a short-term service. Constellation adds that the Commission also did not reject its argument that the Midwest ISO may not limit its recognition of short-term network resources to the 2005 FTR awards, because to do so would violate the Commission's overarching principle that, in allocating FTRs, customers should not be worse off than they were prior to the implementation of the Midwest ISO's Day 2 markets.[17] Constellation argues that the Commission should clarify that the TEMT II Rehearing Order does not authorize the Midwest ISO to restrict FTR awards associated with resources of less than one year's duration to the 2005 FTR awards.[18] It adds that the Commission should also clarify that its reference to seasonal and monthly resources at other points in the TEMT II Rehearing Order were not intended to deny FTR allocations associated with historical resource designations extending for shorter periods. For example, to accommodate retail choice programs within Ohio, the Commission approved

[17] Constellation Request for Rehearing at 7-8 (quoting TEMT II Order at P 156).

[18] As Constellation emphasized in its earlier request for clarification, reliance on network resources that, individually, have a duration less than one year does not, in any way, diminish the obligation of network customers to designate network resources at all times sufficient to meet their obligations under the Midwest ISO tariff.

tariff revisions that allowed network customers to designate network resources on a daily basis as long as the customer concurrently terminated another network resource of similar size.[19] Constellation argues that it is essential that FTR allocations reflect the same flexibility that has been, and is, permitted under the Midwest ISO tariff for network resource designations and not be restricted arbitrarily by terms such as annual, seasonal or monthly.[20]

25. If the Commission denies Constellation's request for clarification, Constellation requests rehearing because the Commission has provided no rational basis to deprive network service customers that rely on a combination of short-term network resources of the right to be protected from congestion consistent with their historical uses of the transmission system. According to Constellation, an FTR allocation process that favors load-serving entities that rely on network resources with a duration of one year or more is discriminatory and inconsistent with the Commission's determination that FTR awards are intended to keep customers whole and maintain the same level and quality of service. Constellation contends that the Midwest ISO's proposal to treat certain network service customers (primarily those that do not own generation resources and rely on contractual procurements) as inferior customers due solely to the duration of their network resource designations is unjust, unreasonable, and unduly discriminatory. Furthermore, argues Constellation, Commission approval of this inferior treatment would be arbitrary and capricious because it departs from the Commission's explicit principles to tie the opportunity for congestion-sheltering FTRs to historical network uses.

26. More importantly, states Constellation, the Midwest ISO's approach would have a detrimental impact on competition in the Midwest ISO, specifically on those customers that are served by competitive suppliers that rely on a combination of network resources, each with a designation of less than one year. Constellation says that there is no reason to penalize these network service customers by depriving them of service equivalent to their historic transmission entitlements and leaving them unhedged against congestion on the transmission system.

[19] *See, e.g., Cinergy Operating Companies*, 93 FERC ¶ 61,176 (2000).

[20] The Midwest ISO has already developed a weighting method for converting less-than-annual network resource designations into FTR allocations, and proposes to apply it to the 2005 FTR awards. Accordingly, the issue is not how to define FTR entitlements; the only issue is whether certain classes of long-term network service customers will be denied FTRs after 2005.

c. Discussion

27. Constellation raised this issue in its answer to the Midwest ISO's October 5 compliance filing. In Compliance Order I, we noted that the TEMT does not adequately explain how FTRs would be allocated beyond the initial allocation for short-term resources and required the Midwest ISO to file the relevant tariff sections not later than 90 days prior to the second annual FTR allocation.[21] On March 10, 2005, the Midwest ISO filed a proposal in Docket Nos. ER04-691-029 and EL04-104-028 to clarify its treatment of long-term seasonal Network Resources. Parties, including Constellation, filed comments and protests. The Commission will address Constellation's concerns with the Midwest ISO's January 21 compliance filing at the time we consider the Midwest ISO's March 10 compliance filing, when we will have the benefit of a fuller record.

2. FTRs for System Purchases

a. Background

28. In the TEMT II Order, the Commission rejected a request by the Midwest TDUs that sellers of system purchase contracts be required to share congestion costs with the buyer under the contract.[22] As explained in that order, system purchases are typically mapped into FTR allocations through a "zonal" FTR that assigns each generator serving the system purchase a weighted share of the total megawatts under the purchase. The Commission required that the Midwest ISO offer the "redirect" option for such zonal FTR requests that the Commission approved for PJM Interconnection, L.L.C. (PJM).[23]

29. The TEMT II Rehearing Order required that the seller of the existing transmission service nominate and hold the FTRs as well as be responsible for congestion charges associated with the delivery of system purchases and encouraged buyers and sellers of system purchases to examine and agree to other approaches for the Commission's consideration prior to the next round of FTR allocation.[24]

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[21] *See* Compliance Order I at P 82.

[22] *See* TEMT II Order at P 182.

[23] *See PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,223 at 16 (2004).

[24] *See* TEMT II Rehearing Order at P 162, 166.

b. Requests for Rehearing

30. The Midwest SATCs note that in the TEMT II Rehearing Order, the Commission considered how so-called "system purchase contracts" should be treated in the context of FTR administration and congestion cost responsibility. The discussion addressed a request for rehearing filed by the Midwest TDUs.[25] According to that request, a typical system purchase contract is designed to enable a small, presumably transmission-dependent utility "to make a power purchase from a large, vertically integrated utility comparable to the internal transactions by which the larger utility supplies bulk power to its own distribution function (backed by the supplier's reserves)."[26]

31. The Midwest TDUs argued, and the Commission agreed, that these types of contracts raise difficult issues from an FTR administration standpoint. Specifically, a system purchase customer has no control over the manner in which the supplier meets its commodity supply obligations under the contract. The Midwest TDUs state that, because the customer cannot control which generation resources are dispatched, the customer is unable to plan its FTR nominations or otherwise manage congestion. In response, the Commission required "the seller of the existing transmission service to nominate and hold the FTRs as well as be responsible for congestion charges associated with delivery of the system purchase."[27]

32. The Midwest SATCs believe the Commission's use of the term "seller of the existing transmission service" was based on the Midwest TDUs' explanation that system purchase services were historically provided by vertically-integrated utilities through the bundling of transmission service and commodity sales. Although this description may have been accurate at one time, the Midwest SATCs state that it is no longer. They note that the Midwest ISO is the Transmission Provider under the TEMT and would be considered the "seller of transmission service" under the most literal of interpretations. The Midwest SATCs state that the Midwest ISO cannot administer FTRs and/or be

[25] *See* Request of Midwest TDUs for Rehearing or Clarification (Sept. 7, 2004).

[26] *Id.* at 33.

[27] TEMT II Rehearing Order at P 162.

responsible for congestion costs related to the system purchase contracts that its customers may enter. They add that even if the seller of transmission service is considered to be the owner of transmission facilities over which service is provided, there are scenarios under which it would be unfair to require the transmission owner to assume these functions.[28]

33. It seems clear to the Midwest SATCs that the Commission did not intend for the "seller of the existing transmission service" to be responsible for FTR administration and congestion costs relating to system purchase contracts. Rather, the Midwest SATCs believe that the intent of this statement was for these FTR and congestion management responsibilities to be performed by the contracting party that is responsible for the supply side of the system purchase contract, i.e., the commodity seller. According to the Midwest SATCs, this entity might be a vertically-integrated utility, as the Midwest TDUs suggest, but it would not be the Midwest ISO or any other entity that is not a party to the system purchase contract.

34. To remove any future uncertainty and to correct the record, the Midwest SATCs request that the Commission provide an appropriate clarification on rehearing. The Midwest SATCs state that they are particularly sensitive to these types of issues because the purchase and sale of FTRs is a market participant function that is fundamentally inconsistent with the stand-alone, transmission-only business structure. As such, the Midwest SATCs wish to correct any language that could be interpreted as requiring them to hold FTRs or become market participants against their will.

c. <u>Discussion</u>

35. We will grant rehearing of the Midwest SATCs' request. Paragraphs 162 and 166 of the TEMT II Rehearing Order incorrectly cite the seller of transmission service as being the entity holding FTRs and being responsible for congestion costs associated with system purchase contracts. Those paragraphs were intended to state that contracting parties responsible for supplies, i.e., sellers of energy, would be required to nominate and hold FTRs and be responsible for congestion charges in the circumstances described by the Midwest TDUs. We direct the Midwest ISO to file revised tariff sheets within 60 days of this order.

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[28] According to the Midwest SATCs, this would be the case if the transmission owner were a stand-alone, transmission-only company that does not participate in energy market transactions, is not a party to the underlying system purchase contract, and has no control over which generation units are dispatched to fulfill contractual energy supply obligations.

3. Locational Marginal Pricing

a. Background

36. In response to a request to permit zonal pricing, the Commission explained in the TEMT II Order that it had approved zonal pricing for load that includes multiple load-serving entities within the zone, but that such zonal pricing was the result of stakeholder processes, not Commission direction. The Commission encouraged stakeholders to consider such aggregations in future discussions, including those involving the formation of independent transmission companies, but did not require that zonal pricing be used.[29]

37. The Commission denied Midwest Municipal Transmission Group's request for rehearing of its decision, on the basis that Midwest Municipal Transmission Group could hedge congestion costs through the allocation or purchase of FTRs, and thereby hedge itself against adverse LMPs. The Commission also encouraged Midwest Municipal Transmission Group to report market abuse violations to the IMM and the Commission. The Commission declined to require the formation of zones at the option of the transmission-dependent utility, stating that it would continue to rely on the stakeholder process to determine pricing zones.[30]

b. Requests for Rehearing

38. Midwest Municipal Transmission Group challenges the Commission's findings regarding zonal and nodal pricing. Midwest Municipal Transmission Group states that its members are often in load pockets. Thus, it can be predicted that for many periods, they will have access to one or two suppliers, leaving the possibility of very high bid prices. According to Midwest Municipal Transmission Group, this means that its members will not have caused, but will be victims of, inadequate infrastructure, which permits high prices. Moreover, high LMP or congestion creates incentives for transmission and

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[29] *See* TEMT II Order at P 223.

[30] *See* TEMT II Rehearing Order at P 212.

generation owners not to fix the grid, as well as for grid improvement, because grid improvements will reduce or eliminate high congestion cost prices. Midwest Municipal Transmission Group notes that infrastructure cannot be built quickly. Whether the result is called the market's allocating shortage or market power abuse,[31] inadequate transmission leads to high prices, which ultimately can force smaller systems from business, thereby decreasing competition.

39. Midwest Municipal Transmission Group states that it urged that the Commission follow its White Paper suggestion and provide Midwest Municipal Transmission Group members and others similarly situated with the option of averaging their LMPs with those of others in their pricing zone or on a broader basis.[32] Midwest Municipal Transmission Group states that this approach would be especially equitable where infrastructure cannot be immediately built, and therefore the problem would not correct itself. Midwest Municipal Transmission Group recounts its arguments on rehearing that larger entities would not perceive a need for nodal averaging, and would not want to benefit smaller competing systems. According to Midwest Municipal Transmission Group, the reasons for this parallel those of past decades, where large systems did not want to share reserves on an equal basis with smaller municipal competitors.[33] Midwest Municipal Transmission Group states that where discrimination against smaller systems will result, the Commission must prevent abuse.[34]

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[31] Midwest Municipal Transmission Group argues that where buyers cannot reach alternative power supply sources due to inadequate transmission, the economic result is the same, regardless of whether the seller purposefully acted to monopolize. The reason for regulation is that companies may have market power. Midwest Municipal Transmission Group adds that, moreover, while inadequate transmission may have many causes, ultimately dominant transmission providers have been responsible for grid adequacy.

[32] Midwest Municipal Transmission Group Request for Rehearing at 4-5 (citing White Paper: Wholesale Power Market Platform, Appendix A at 10, *available at* http://www.ferc.fed.us/industries/electric/indus-act/smd/white_paper.pdf).

[33] Midwest TDUs Request for Rehearing at 5 (citing *Gainesville Utils. Dep't v. Florida Power Corp.*, 402 U.S. 515 (1971) (*Gainesville*); *Consumers Power Co.*, 6 N.R.C. 892 (1977)).

[34] *Id.* (citing *Gulf States Utils. Co v. FPC*, 411 U.S. 747 (1973)).

40. Midwest Municipal Transmission Group states that the Commission misapprehended the requirements of *Gainesville*. It argues that in that case, the Commission, affirmed by the Supreme Court, held that larger utilities like Florida Power Corporation had to interconnect with smaller systems like Gainesville, share reserves, and buy and sell interchange. Further, Midwest Municipal Transmission Group argues, it held that larger utilities could not impose special charges or higher rates for doing so, even though the value of having an interconnection and of reserves sharing was greater for smaller utilities than larger ones.

41. Midwest Municipal Transmission Group indicates that the Commission is correct that *Gainesville* concerned "the cost of providing service and facilities," but it ignores that Florida Power Corporation refused to interconnect and share reserves unless it could receive special payments.[35] According to Midwest Municipal Transmission Group, *Gainesville* stands for the proposition that larger systems may not advantage themselves from internal aggregations and deny or limit similar benefits to smaller systems by measuring the benefits from dealing with smaller systems on an incremental basis after taking into account larger system aggregations. Thus, according to Midwest Municipal Transmission Group, *Gainesville* prohibits those who aggregate from then excluding smaller entities or from charging them proportionately extra to allow participation.[36]

42. Midwest Municipal Transmission Group argues that it is incorrect to suggest that *Gainesville* merely involved cost allocations. To be sure, states Midwest Municipal Transmission Group, Gainesville paid for the interconnection, but the services to be provided were required and were ordered to be non-discriminatory. In the situation here, Midwest Municipal Transmission Group claims that the impacts of LMP would be disparate between larger and smaller utilities due to smaller utilities' size and limited nodes as well as due to limitations of the grid, which was constructed by transmission owners to further their own economic needs. Midwest Municipal Transmission Group opines that, just as Florida Power Corporation was advantaged by its ability to share reserves internally on its system, the Midwest ISO TOs are advantaged by their ability to

[35] Midwest Municipal Transmission Group Request for Rehearing at 8 (citing *Gainesville Utilities Department and City of Gainesville, Florida v. Florida Power Corporation*, 41 F.P.C. 4, 6, 8 (1969)).

[36] *Id.* (citing *Associated Press v. United States*, 326 U.S. 1 (1945) (Sherman Act violation to exclude competing newspapers from Associated Press news sharing); *Mid-Continent Area Power Pool Agreement,* 58 F.P.C. 2622, 2631-36, *reh'g denied,* 59 F.P.C. 1651 (1977), *aff'd*, *Central Iowa Power Coop. v. FERC,* 606 F.2d 1156, 1166-70 (D.C. Cir. 1979) (non-discriminatory pool membership ordered)).

average LMP across multiple nodes, as they do now internally on their systems. For the same reasons that people buy insurance, according to Midwest Municipal Transmission Group, no one can doubt the benefits to larger systems and their customers of such internal nodal averaging. Midwest Municipal Transmission Group concludes that excluding the benefits to smaller systems is unjust and discriminatory.

43. Midwest Municipal Transmission Group states that the Commission's orders and White Paper show that the Commission recognizes that there is merit in Midwest Municipal Transmission Group's recommendations.[37] They add that this should resolve the matter, because absent averaging nodes there is a clear discriminatory impact against which larger systems can insure internally. Midwest Municipal Transmission Group avers that the aggregation and averaging that it proposes is in accord with "the general principle that each utility should carry a proportionate burden," for which *Gainesville* stands.[38] But, states Midwest Municipal Transmission Group, the Commission says that it prefers to "continue to rely on stakeholder processes to determine pricing zones."[39]

44. Midwest Municipal Transmission Group states that if its members may be subject to unjust rates and discriminatory impacts, the Commission must cure the problem. The group states that the Commission cannot delegate its statutory obligations to a stakeholder process, regardless how useful such process may be for other purposes. Larger, competing utilities will have no interest in resolving problems of discrimination or unjust rate payments against their competitors. Midwest Municipal Transmission Group states that as an independent regulatory commission, the Commission must determine the public interest regardless of stakeholder preferences.[40] Finally, Midwest Municipal Transmission Group challenges the Commission's statement that if adverse impacts occur, Midwest Municipal Transmission Group may file a complaint and that

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[37] Midwest Municipal Transmission Group states that in *New England Power Pool and ISO New England, Inc*., 106 FERC ¶ 61,059 (2004) (*NEPOOL and ISO-NE*), the Commission recognized that other factors could militate against implementing full nodal pricing for load.

[38] Midwest Municipal Transmission Group Request for Rehearing at 9 (citing *Consumers Power Co. (Midland Plant, Units 1 and 2)*, 6 N.R.C. 892, 1074-75 (1977)).

[39] TEMT II Rehearing Order at P 214.

[40] Midwest Municipal Transmission Group Request for Rehearing at 10 (citing *City of Lafayette v. SEC*, 454 F.2d 941, 951-52 (D.C. Cir. 1971), *aff'd sub nom. Gulf States Utils. Co. v. FPC*, 411 U.S. 747 (1973)).

there are protections against market abuse. Midwest Municipal Transmission Group states that the adequacy of these protections is at issue or is unknown, that they must be measured against the impact of the $1,000/MWh bid cap, and that the existence of these remedial procedures does not eliminate harm.

c. Discussion

45. The basis for Midwest Municipal Transmission Group's request is an unsubstantiated assumption that there is an "overwhelming likelihood" that load-serving entities receiving supplies at one price node will suffer higher LMP prices than entities able to access multiple suppliers via many nodes since these entities can average high and low price nodes and will be less likely to be in load pockets. We have no evidence to support this contention, either in this energy market or any other ISO energy market and, considering there are a myriad of other factors that will influence LMPs besides the size of the purchasing entity, we question whether any consistent relation could be made between entity size and LMP.[41]

46. We continue to find that Midwest Municipal Transmission Group reads too much into *Gainesville*. *Gainesville* concerned a Commission-ordered interconnection under section 202(b) of the Federal Power Act (FPA), designed to facilitate reserve sharing and thereby to improve the economic efficiency of two Florida utilities.[42] It analyzed the Commission's refusal to condition that interconnection on the smaller utility paying an annual fee to the larger one, when the Commission found that benefits accrue to both parties as a result of the interconnection. Neither the Commission's orders nor the Supreme Court's opinion contain the sweeping language of general applicability that

[41] We encourage market participants to report to the IMM and the Commission when LMP prices are high and local generators are exerting market power in circumstances where the market participants are dependent on these local generators and these market participants do not own the generators.

[42] *See Gainesville*, 402 U.S. at 523-24 ("[T]he Commission found that even if the interconnection were evaluated on the basis of relative benefits, 'this record shows that the proposed intertie will afford both parties opportunities to take advantage of substantial and important benefits: electrical operating benefits, and corporate financial savings.'"). The opinion does not analyze whether the Commission may properly condition an interconnection when one party receives no benefits. *Id.* at 529.

Midwest Municipal Transmission Group argues they do. And Midwest Municipal Transmission Group's arguments here arise from a very different factual background than *Gainesville* described: they concern whether the impact of various provisions of a tariff approved under section 205 of the FPA will be unjust, unreasonable, or unduly discriminatory.

47. The Commission considers nodal pricing for load to be a just and reasonable pricing method, as it provides price transparency and accurate price signals for demand response.[43] However, as in New England, we will reconsider the requirement that the parties implement this type of pricing if they can demonstrate that other pricing methods will also achieve much or all of the transparency provided by nodal pricing, while providing other benefits (for example, lower costs).[44]

48. While the White Paper recognizes that RTOs and ISOs may use either zonal or nodal prices, *NEPOOL and ISO-NE* also recognizes that the adoption of alternative pricing will be the result of stakeholder processes and analyses that address the impacts of different pricing schemes.[45] Therefore, the fact that the White Paper recognizes alternative options does not resolve the matter, as Midwest Municipal Transmission Group contends. Midwest Municipal Transmission Group's proposal must be evaluated by the ISO in terms of its disadvantages, such as loss of price transparency, as well as its purported advantages based on market evidence.

49. We disagree with Midwest Municipal Transmission Group that the stakeholder process is simply a measurement of stakeholder preferences, and that allowing the process to go forward amounts to an impermissible delegation of the Commission's statutory authority. Stakeholders have more market data available to them than the Commission does, and more hands-on experience with day-to-day market operations; as a result, they are in the best position to accurately assess what pricing models are feasible in a given region. As the ISO New England process showed, stakeholder processes will yield the full range of analytical results necessary to evaluate whether an alternative pricing model is in the public interest. The stakeholder process, however, is not the end of the analysis: it is used to generate proposals that, to become effective, must be filed

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[43] *NEPOOL and ISO-NE*, 106 FERC ¶ 61,059 at P 15.

[44] *See id.*

[45] *Id.* at P 17, 19 (noting that the Midwest ISO and its stakeholders were evaluating the benefits and disadvantages of different options, and encouraging New England parties to take up the issue in their stakeholder process).

under section 205 of the FPA and merit Commission approval. If Midwest Municipal Transmission Group is concerned that the proposal is unjust, unreasonable, or unduly discriminatory, it will have an opportunity to make its views known to the Commission and considered along with the pricing proposal. For these reasons we deny the request for rehearing.

50. Nonetheless, considering both the advantages of the stakeholder process, and in particular the benefits of an independent system operator that can conduct unbiased system studies, and the lack of evidence on LMP prices, we direct the Midwest ISO to evaluate the price disparities for single price node entities and multiple price node entities based on the first six months of system operations, present those results to stakeholders, and make an information filing at the Commission detailing results, proposals for next steps and alternatives, if appropriate, to be filed one year after market start-up.

D. Market Monitoring and Market Power Mitigation

1. Prospective Application of Mitigation

a. Background

51. The TEMT II Order required the Midwest ISO to make a compliance filing to implement an automatic mitigation procedure or other measures (such as manual expedited mitigation) to prevent the one-day lag in mitigation that would otherwise occur in the day-ahead market.[46]

52. Recognizing the other tasks facing the IMM in the short time frame before market start, the Commission's change in position on this issue, and the IMM's concerns about the possibility for harm in instituting manual mitigation, the TEMT II Rehearing Order permitted the IMM to delay adoption of automated mitigation or expedited manual mitigation for the day-ahead market and thus to remove language for the avoidance of the one-day delay by using automated mitigation with the exclusive use of the conduct test language for the day-ahead market from its tariff, and required the IMM: (1) to file quarterly reports to show where mitigation would have been applied were there not a lag in mitigation and the associated dollar impact on the market, (2) to develop a safety-net plan for instituting mitigation if a pattern of behavior develops in the day-ahead market in

[46] *See* TEMT II Order at P 344.

which mitigation is repeatedly needed but cannot be applied due to the lag, and (3) to file a plan and associated timeline under which it will resolve this problem for the longer term by instituting automated or expedited manual mitigation in the day-ahead market.[47]

b. Requests for Rehearing

53. The Midwest TDUs state that in the TEMT II Order, the Commission correctly ruled that the Midwest ISO should implement automated or expedited manual mitigation in the day-ahead energy market, but the TEMT II Rehearing Order reversed that decision. On rehearing, the Midwest TDUs urge the Commission to reinstate the automated or expedited manual mitigation requirement or, in the alternative, require the Midwest ISO to maintain cost-based bidding in its markets until automated or expedited manual mitigation is in place in day-ahead markets.

54. The Midwest TDUs first argue that the Commission has not fulfilled its duty to protect consumers. They argue that the TEMT II Rehearing Order wrongly accepted the IMM's representation that automated or expedited manual mitigation conflicted with the timeline for energy market start-up. They also state that the FPA mandates just and reasonable rates, but not LMP or a date certain for energy market start-up.

55. The Midwest TDUs argue that the Commission cannot permit market-based sales absent "empirical proof" that "existing competition would ensure that the actual price is just and reasonable."[48] The Ninth Circuit recently held that the Commission's ability to rely upon a market-based pricing regime depends upon the finding that a seller "lacks market power (or has taken sufficient steps to mitigate market power), coupled with strict reporting requirements to ensure that the rate is 'just and reasonable' and that markets are not subject to manipulation."[49] The Midwest TDUs add that the FPA does not make

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[47] *See* TEMT II Rehearing Order at P 259.

[48] Midwest TDUs Request for Rehearing at 5 (citing *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984)).

[49] *Id.* (citing *State of California, ex rel. Bill Lockyer, Attorney General v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004)).

exceptions that allow the Commission to ignore market power in some markets, but that it requires the Commission to ensure consumers a "complete, permanent and effective bond of protection" against unjust and unreasonable rates.[50]

56. The Midwest TDUs allege that under the Midwest ISO market design, prices charged in the day-ahead energy market could be the result of market manipulation absent an automated or expedited manual mitigation system.[51] Such prices would be neither just and reasonable nor lawful. The TEMT II Rehearing Order, according to the Midwest TDUs, ignores this unlawfulness and credits the IMM's representation that developing automated mitigation or expedited manual mitigation "would divert limited resources from getting the Midwest ISO market started."[52] They add that the Commission's priorities in granting the delay were wrong because the FPA does not mandate LMP markets.[53] By contrast, the Midwest TDUs claim, consumer protection in the form of mitigation covering the full range of opportunities to exercise market power is mandated if the Commission wants to rely on LMP where those markets pose acknowledged risks of unmitigated market power exercise.[54]

57. The Midwest TDUs argue that neither the IMM nor the Commission claims that the exercise of market power will not arise in day-ahead energy market; rather, they are more concerned with the Midwest ISO's start-up calendar. As a result, say the Midwest TDUs, the Midwest ISO is the only organized market in which the Commission knowingly allows market power to go unmitigated for at least the first day in which a given market participant's exercise of market power violates the approved conduct and impact thresholds.

[50] *Id.* (citing *Atlantic Ref. Co. v. Pub. Serv. Commission*, 360 U.S. 378, 388 (1959)).

[51] *Id.* (citing TEMT II Order at P 341).

[52] *Id.* (citing TEMT II Rehearing Order at P 257).

[53] "[T]he just and reasonable standard does not compel the Commission to use any single pricing formula." *Mobil Oil Exploration & Producing Southeast Inc. v. United Distribution Co.*, 498 U.S. 211, 224 (1991). *See also FPC v. Texaco, Inc.*, 417 U.S. 380, 394 (1974).

[54] *AEP Power Mktg.*, 107 FERC ¶ 61,108, P 40; *Lockyer*, 383 F.3d at 1013.

58. Second, the Midwest TDUs state that the TEMT II Rehearing Order allowed the IMM to delay implementing automated mitigation on the grounds that the Commission had changed its position on this issue. They argue that the Midwest ISO and the IMM first noted in December 2002 that automated mitigation might be needed if manual mitigation could not occur in a timely manner; thus, they must have known about the potential need to develop software. In August 2003, the IMM confirmed that mitigation in the day-ahead market could not be done until the day after the harm had occurred.[55] According to the Midwest TDUs, although the IMM said that the size of the Midwest ISO market compared to NYISO's (where the ISO uses automated mitigation) makes developing software more difficult, the size difference only underscores the need for automation and the possibly great amount of harm resulting from its absence. The Commission should not have permitted the IMM to use software challenges as an excuse to avoid the requirements of the FPA and the TEMT II Order.

59. Third, the Midwest TDUs argue that the Commission's confidence in the real-time energy market to protect against the exercise of market power in the day-ahead energy market is misplaced. They state that there is no sound basis for this conclusion, and that the Commission should not have delayed automated or expedited mitigation because of it.

60. The IMM claimed that buyers' ability to abandon the day-ahead market through price-sensitive bids protects them from any market power risk arising from the delay in mitigation in the day-ahead market, say the Midwest TDUs. They add that buyers can realize protection using price-sensitive bids only if they are lucky or prescient enough to submit a price-sensitive bid at the competitive level. The Midwest TDUs state that supra-competitive prices still may be lower than a price-sensitive bid, and in such cases buyers are still harmed and the market-clearing price is still unjust and unreasonable. The Midwest TDUs argue that virtual trading suffers from similar problems. Although the IMM claims that virtual trading would occur immediately and would result in a reduction of day-ahead purchases, the Midwest TDUs argue that virtual trading also involves price-sensitive bids,[56] and thereby fails to offer protection. In addition, if a virtual bidder did change its bid for the next day in response to a price increase, market conditions may have changed such that any ameliorating effect of its response will not be realized.

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[55] Midwest TDUs Request for Rehearing at 8 (citing Comments of Midwest TDUs on Technical Conference at Attachment C, Docket No. ER03-323-000 (Aug. 8, 2003) *available at* http://elibrary.ferc.gov/idmws/Filelist.asp?document id=4127409).

[56] Module C, section 39.2.7.

61. The Midwest TDUs believe that shifting purchases to the real-time energy market is contrary to the Midwest ISO market design. That design, they say, is predicated on the expectation that market participants will do the bulk of the trading bilaterally, use the day-ahead market to reconcile their long positions with close estimates of their actual loads, and use the real-time markets only to reconcile errors or deal with generation outages. The Midwest TDUs believe that it is unrealistic to assert that buyers can abandon the day-ahead market and immediately move to real-time market if they become suspicious about business in the day-ahead market.

62. Further, the Midwest TDUs argue that shifting to the real-time market exposes buyers to greater congestion risk. Because the day-ahead market is used to close all FTR positions, shifting transactions to real time could adversely affect FTR values, making them a less effective hedge. The Midwest TDUs argue that the shift to the real-time market will also undermine the effectiveness of the Midwest ISO unit commitment process, and will result in greater reliance on the RAC process, the higher costs of which are borne by those in the real-time market. Thus, the identified avoidance strategies do not address harms resulting from the absence of automated mitigation.

63. Fourth, the Midwest TDUs argue that the IMM has not shown that expedited mitigation is not a viable option, and that the Commission should not have concluded on the record before it that expedited manual mitigation cannot be made to work. The Midwest TDUs recount that the IMM indicated that it had "been working to develop alternatives for applying the conduct and impact tests in the Day-Ahead Markets, such as expedited manual mitigation procedures . . ." and that it stated that expedited manual mitigation presumably would involve" some truncated form of the conduct and impact tests."[57] According to the Midwest TDUs, these statements suggest that the IMM has done little to try to develop a method of expedited manual mitigation. In response to the Midwest TDUs' suggestion that the conduct and impact tests be run with unit

[57] Midwest TDUs Request for Rehearing at 10 (quoting IMM Request for Clarification at 2, 10 (Sept. 13, 2004)).

commitment assumed fixed, the IMM merely asserted, but offered no evidence, that such an approach would "still require price and schedule revisions after the initial Day-Ahead posting."[58] On this record, state the Midwest TDUs, the Commission should not have concluded that expedited manual mitigation cannot be made to work.[59]

64. The Midwest TDUs argue that worries about "false positives" also do not provide a basis to reject expedited manual mitigation.[60] If market power risks are as low as the IMM maintains, contend the Midwest TDUs, it should be possible to design manual, expedited mitigation approaches so that false positives are rare. Sellers can reduce those risks even further by notifying the IMM of changes in marginal costs that should result in a change in their references levels.[61] Moreover, if the mitigation measures continue to have overly generous conduct and market impact thresholds, any "false positives," as measured against those thresholds, may nonetheless be exercises of market power in fact and properly mitigated, according to the Midwest TDUs.

65. The Midwest TDUs are concerned that a seller submitting excessive bids can avoid being caught such that mitigation is never imposed, let alone continued. The IMM previously told the Commission that "[m]itigation is applied in the day-ahead market if the conduct test is failed and the conduct-impact test was failed in the previous day's

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[58] *Id.* at 11 (quoting IMM Request for Clarification at 10 (Sept. 13, 2004)).

[59] Another possible approach proposed by the Midwest TDUs involves running simultaneous day-ahead market solutions, one as-bid and the other with conduct-test violating bids set to the appropriate default levels. If the latter run shows any LMPs reduced by the applicable market impact thresholds, those results, rather than the as-bid results, would be used. If there are no conduct-test violations, the second run would simply provide a backup for the first. This approach, claim the Midwest TDUs, should take virtually no extra time and would not mitigate anyone unless an impact-test violation occurred. While it might require extra hardware, this should not require any significant new software.

[60] In fact, argue the Midwest TDUs, the IMM expressed concerns about false positives with respect to automated mitigation. *See* Midwest TDUs Request for Rehearing at 11 (citing Prepared Direct Testimony of David B. Patton, Ph.D. at 35 (Mar. 31, 2004)).

[61] *Id.* (citing Module D, section 64.3).

day-ahead market (and market conditions have not changed substantially)."[62] The Midwest TDUs understand the IMM's statement to mean that sellers must fail the conduct test twice before the mitigation measures are applied, while bids that clearly violate the mitigation measures will not be remedied. They state that if the seller does not fail the conduct test the day after it had failed the conduct-impact test (when mitigation should have been imposed) and market conditions have substantially changed (which will be the case in many instances), the seller avoids mitigation altogether. Accordingly, a seller that submits a bid on Monday that fails both the conduct and market impact thresholds, followed by a compliant bid on Tuesday, can avoid mitigation and retain the benefit of its excessive bid on Monday. The Midwest TDUs state that on Wednesday, the seller can again submit a bid that fails both the conduct and market impact thresholds. They conclude that automated or expedited manual mitigation should be in place to prevent such gaming from undermining Midwest ISO markets and injuring consumers.

66. Fifth, the Midwest TDUs allege that until proper mitigation is in place, the only way to protect customers is to use cost-based bidding. They note that the TEMT II Rehearing Order required the IMM to: (1) file quarterly reports to show where mitigation would have been applied were there not a lag in mitigation, and the associated dollar impact on the market; (2) develop and file a safety-net plan for instituting mitigation if a pattern of behavior develops in the day-ahead market in which mitigation is repeatedly needed but cannot be applied due to the lag; and (3) file a plan and associated timeline under which it will resolve this problem for the longer term by instituting automated or expedited manual mitigation in the market.[63] The Midwest TDUs state that these actions will not prove sufficient to protect consumers because they provide only after-the-fact options to attempt to remedy harm arising from the exercise of market power in the day-ahead market. The Midwest TDUs state that they are concerned that subsequent refund proceedings, especially cases like those for California, would not provide the "complete, permanent and effective bond of protection" against unjust and unreasonable rates demanded by the FPA.[64] They add that in other RTO contexts that "*ex post facto* market action results in market disruptions and generates uncertainty for all market participants."[65]

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[62] *Id.* at 11-12 n.21 (citing IMM, *Response to Data Requests of the Independent Market Monitor* at 8, Docket No. ER03-323-000 (Sept. 5, 2003)).

[63] *Id.* at 13 (quoting TEMT II Rehearing Order at P 259).

[64] *Id.* (citing *Atlantic Ref Co. v. Public Serv. Comm'n*, 360 U.S. 378, 388 (1959)).

[65] *Id.* (citing *ISO New England, Inc.*, 104 FERC ¶ 61,039 at P 38 (2003)).

67. Further, the Midwest TDUs allege that the Commission's requirements evidence its "continuing unease about the ability of [Midwest ISO] markets to provide adequate consumer safeguards from the outset." They indicate that similar concerns, along with recognition of its statutory responsibilities, prompted the Commission to require that all bids into Midwest ISO markets be cost-based for the first 60 days of operation.[66] To address concerns about the absence of timely mitigation in the day-ahead market, the Midwest TDUs state, the Commission must maintain its requirement for cost-based bidding in all Midwest ISO markets until the Midwest ISO and the IMM implement automated or expedited manual mitigation procedures in the day-ahead market. Requiring cost-based bids charts a clear, true path to compliance with the FPA's just and reasonable standard, according to the Midwest TDUs.

68. The Midwest TDUs aver that cost-based pricing is consistent with the treatment of PJM companies during the early stages of the restructured PJM markets. The Midwest TDUs note that during the first two years of LMP-based markets in PJM, the PJM Companies were limited to submitting bids capped at their marginal operating cost of producing energy.[67] Start-up and no-load bids were similarly cost-based. Only upon submission and Commission review of studies demonstrating that these companies lacked market power was greater bidding flexibility allowed, according to the Midwest TDUs.[68] This history, contends the Midwest TDUs, should instruct the Commission's course of action here, to ensure that customers pay only just and reasonable prices.

c. <u>Compliance Filing and Responsive Pleadings</u>

69. The IMM proposes a safety-net plan for day-ahead mitigation, with two components. The first component is as follows:

- First, the IMM would perform conduct tests for day-ahead generation offers after the day-ahead energy market closes for an operating day, using market mitigation software that compares day-ahead generation offers to the generators' respective reference level (plus the applicable Broad Constrained Area (BCA) or NCA threshold).

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[66] *Id.* at 13-14 (citing TEMT II Order at P 62-63).

[67] *Id.* at 14 (citing *Atlantic City Elec. Co.*, 86 FERC ¶ 61,248, 61,893 (1999)).

[68] *Id.* (citing *Atlantic City Elec. Co.*, 86 FERC ¶ 61,248 at 61,902).

- Second, if any component of the offer fails the conduct test in an active BCA or NCA, the IMM will perform an impact test to determine the effect of the conduct on the day-ahead market for the operating day, by substituting default offers for those components that fail the conduct test.

- Third, for those BCAs and NCAs that show a market impact larger than the thresholds, the generating resources will be identified for mitigation for the following day and will be mitigated if they exceed the conduct test in the following day.

70. The second component of the plan would subject resources to mitigation for up to one week if units owned or operated by the same supplier in the same BCA or NCA fail the conduct and impact test in the operating day after having previously also failed both mitigation tests recently, e.g., in the prior 90 days. The supplier's resources would need to fail the conduct test to be actually mitigated in the day-ahead market for days operating day plus one through operating day plus seven. The IMM proposes to notify the Office of Market Oversight and Investigation (OMOI) any time an extension of the mitigation measures in the day-ahead market is warranted, so that the Commission can review and approve the extension prior to its application.

71. The IMM proposes the following timeline for implementation of long-term day-ahead mitigation solutions:

- July 15, 2005 – presentation of alternative long-term day-ahead mitigation solutions and IMM recommendations, and quarterly report;

- September, 2005 – Midwest ISO tariff filing to implement long-term solution; and

- March, 2006 – Implement long-term day-ahead mitigation process.

72. Detroit Edison asks the Commission to reject the IMM's proposed safety-net plan for mitigation in the day-ahead energy market. It argues that the plan is ambiguous, questioning how the IMM would determine whether resources should be mitigated for one day or one week. It also states that the plan would hamper the development of Day 2 energy markets by subjecting all generators in BCAs to penalties for actions that may be attributable to genuine supply scarcity. Detroit Edison notes that, because BCAs will not be defined prior to any day-ahead market power mitigation effort, this exposure is ongoing and indefinite. Detroit Edison argues that it will discourage suppliers from participating fully in the energy markets.

73. In light of *Edison Mission Energy v. FERC*,[69] Detroit Edison argues that the Commission must seriously question the appropriateness of any day-ahead market power mitigation proposal that could significantly harm the development of Day 2 energy markets. This is especially so, Detroit Edison says, because the Commission has recognized that "mitigation in the real-time market will significantly dampen the ability of market participants to exercise significant market power in the day-ahead market."[70] Detroit Edison avers that the potential for short-term and long-term harm outweighs any potential short-term benefits.

74. Coalition MTC and the Midwest TDUs argue that the IMM's compliance filing does not address the Commission's requirements for the IMM to: (1) file a plan and a timeline under which it will institute automated or expedited manual mitigation; and (2) enact such mitigation as soon as possible.[71] Coalition MTC and the Midwest TDUs state that the IMM has not submitted a plan, but proposes to provide alternative day-ahead mitigation solutions and recommendations on July 15, 2005, and this suggestion does not comply with the Commission's directives. Coalition MTC and the Midwest TDUs argue that there is no reason to delay compliance, advocate that the Commission reject this aspect of the compliance filing, and request that the Commission again direct the IMM to submit a plan that identifies the specific elements that will be undertaken to implement its directives. They also ask the Commission to direct the IMM and the Midwest ISO to avoid unnecessary delays in the implementation of automated or expedited manual mitigation measures.

75. Coalition MTC and the Midwest TDUs argue that the first component of the IMM's safety-net plan – implementing the original plan without automated or expedited mitigation measures – is a logical application of the TEMT II Rehearing Order, and that a "safety-net" label is inappropriate in the context of that order. They also allege that the second component of the safety-net plan lacks the detail necessary to evaluate its reasonableness. Coalition MTC and the Midwest TDUs note, for example, that the IMM's compliance filing refers to both "units" and "resources" of a supplier failing the conduct or impact tests. They state that the tests evaluate bidding behavior; therefore, the use of "resources" and "units" is not clear. They ask whether, if a single unit fails the conduct and impact tests more than once in a 90-day period, the additional mitigation

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[69] 394 F.3d 964 (D.C. Cir. 2005).

[70] Detroit Edison Protest at 2-3 (quoting TEMT II Rehearing Order at P 258).

[71] Coalition MTC and Midwest TDUs Protest at 3 (citing TEMT II Rehearing Order at 259; Compliance Order I at P 124).

measures apply only to that unit or to all units under common ownership. Further, Coalition MTC and the Midwest TDUs state that BCAs develop dynamically over time, and that a region that is a BCA one day may not be a BCA the following day, or may become part of an entirely different BCA. Coalition MTC and the Midwest TDUs therefore question how the IMM would interpret which population of generation units would be within the "same BCA" over time. They ask the Commission to require the IMM to provide additional supporting details regarding the precise application of the second safety-net measure.

76. Second, Coalition MTC and the Midwest TDUs argue that the IMM should modify the safety-net plan to remove unnecessary IMM discretion regarding whether to impose mitigation. They advocate requiring the IMM to put sellers' units on the IMM's watch list for seven days, rather than choosing anywhere between one and seven days, because the IMM has not justified having this discretion. They also submit that a seller's success in exercising market power on an individual operating day provides strong evidence that its subsequent bids from within the same BCA or NCA that exceed the conduct threshold will also exceed the impact threshold, and argue that a seller's units in the same BCA or NCA should be on the watch list regardless of whether the unit or units failed both the conduct and impact tests in the recent past. Coalition MTC and the Midwest TDUs argues that the requirement of Commission review and approval before a seller is put on the watch list should be eliminated. They state that the IMM justifies review and approval based upon the discretion it proposes to exercise in choosing whether to extend the mitigation watch for up to 7 days; because this discretion is unnecessary, and can be eliminated, Coalition MTC and the Midwest TDUs state that the requirement for Commission approval can be eliminated as well. They note, however, that the IMM does not describe how Commission notification and approval can be accomplished within seven days, and that if the Commission cannot act in that time frame, the window for mitigation will close.

d. Discussion

i. Requests for Rehearing

77. The Commission's decision on AMP was bound by the facts. As the IMM has stated, and repeated in its January 7 compliance filing, the software is not capable of providing AMP and therefore the IMM would only be able to implement a manual expedited mitigation method that results in a footprint-wide mitigation procedure that

would mitigate any and all bids over the conduct thresholds.[72] We find this expedited mitigation unacceptable, since it would result in large-scale mitigation in competitive markets, to the detriment of market efficiency and stifling the incentive for generators to offer supplies into the market.

78. We note, as Detroit Edison does, that the Court of Appeals has cited concerns with mitigation plans that mitigate workably competitive markets, suppress prices and deter market entry.[73] And we recognize that the mitigation plan could result in potentially above-market costs for some customers for one day before the IMM institutes mitigation, if virtual supply offers are insufficient to counteract abusive day-ahead bidding and customers do not avail themselves of real-time market alternatives. Real-time energy costs also may be higher if more generation must be scheduled in the real-time market, as a result of market reactions to day-ahead abuses. Nonetheless, we consider the potential harms of this one-day lag in mitigation to be lower, and the cost impact to be less, than the potential harm of footprint-wide mitigation for all days.[74] As well, we expect that the Commission will provide remedies for above-market costs as identified by the IMM as part of its monitoring in the safety-net plan. We therefore disagree with Detroit Edison that the safety-net plan will do more harm than good. As Detroit Edison and other market participants gain experience with the Day 2 energy markets, they may file a complaint with the Commission if it appears that the safety-net plan is adversely affecting the energy markets.

79. Contrary to the Midwest TDUs' assertions, we do not consider this mitigation method to be in violation of the FPA. The Commission has found that the Midwest ISO's plan to operate as a single energy market is just and reasonable, and therefore consistent with the provisions of the FPA.[75] We therefore reject the Midwest TDUs'

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[72] The IMM asserts that the size of the Midwest ISO market, combined with software limitations at start-up, would make it impossible to run a conduct test and then an impact test, and still rerun the model to produce a new set of market clearing prices and quantities in time to post prices by the established deadlines. TEMT II Rehearing Order at P 254. Nothing in the record refutes the IMM's assertion.

[73] *See Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 969 (D.C. Cir. 2005).

[74] We also note that the other expedited process alternative proposed by the IMM would require retroactive revisions of day-ahead prices two or more hours after prices are initially posted, thereby hindering price certainty. *See* IMM Compliance Plan at 2.

[75] *See* TEMT II Order.

proposal to institute cost-based bidding until AMP is implemented. As we have stated in previous orders, the purpose of the two-month cost-based bidding is solely to ease the market start-up transition and is not a mitigation measure. We consider the safety-net plan for day-ahead mitigation to be an effective mitigation plan that, in combination with the virtual supply offer feature of the energy market and the real-time market alternatives, will minimize the potential for harm or higher costs while ensuring customers obtain the full efficiency benefits of the market. For these reasons, we deny the request for rehearing.

ii. The IMM's Compliance Filing

80. We clarify for the IMM that the Commission approved the original mitigation proposal in the TEMT II Rehearing Order. We agree with Coalition MTC and the Midwest TDUs that the first component of the IMM's safety-net plan – implementing the conduct and impact tests and using the default bid in the next day's market when the entity fails the test – is part of the existing tariff, and not part of the safety-net plan. When the Commission acknowledged the difficulty for the Midwest ISO in applying mitigation in the first day of the day-ahead market, it allowed for the one-day lag in the mitigation on an interim basis as the IMM requested. The Commission did not address, and thus clarifies that it did not remove, mitigation measures for the day after a violation of the conduct and impact thresholds (the operating day plus one). These mitigation measures are in place and have already been approved by the Commission. Thus, we consider the safety-net plan under consideration here to be the plan to subject resources to mitigation for up to a week if units owned or operated by the same supplier in the same BCA or NCA fail the conduct and impact test in the operating day after having failed both tests within the previous 90 days.

81. We believe Detroit Edison's concerns with the safety-net plan are primarily with the Midwest ISO's mitigation plan. Inasmuch as we have previously stated that the BCA penalty, the market price adjusted for bids exceeding a default threshold of $100 or 300 percent above reference levels, is not severe and that the BCA is defined as a constrained area that has indications of market power in the Generation Shift Factor (GSF) analysis,[76] we do not agree with Detroit Edison's conclusion that application of BCA penalties will hamper development of Day 2 markets or apply to genuine supply scarcity situations. Also, we disagree with Detroit Edison's contention that because BCAs will not be identified in advance, market participants will not participate fully.

[76] GSF measures a generation resource's incremental increase or decrease in flow on the flowgate associated with an incremental increase or decrease in the generation resource's output.

Market participants will always know their reference level and therefore will always know when they are bidding in excess of their conduct thresholds, eliminating uncertainty on the application of mitigation measures. Finally, since the safety-net mitigation is only applied for seven days to a supplier in a constrained area after conduct and impact thresholds have been exceeded twice within 90 days, we do not see the period of time over which mitigation would apply to be onerous.

82. The Court of Appeals's decision in *Edison Mission Energy v. FERC*[77] does not change our assessment of the Midwest ISO mitigation plan. That case dealt with automatic mitigation, applied when unmitigated day-ahead prices were expected to exceed $150/MWh absent mitigation in a given area of New York, to all bids that exceed specific thresholds for conduct and market impact. The court held that the presence of workable competition in areas of New York subject to the mitigation would suggest that many, and possibly all, of the bids triggering mitigation would be due to temporary scarcity rather than the exercise of market power. Without sufficient consultation, generators may be mitigated when scarcity rather than market power exercise is at work. The Midwest ISO mitigation measures apply mitigation only to bids in excess of conduct and impact thresholds in defined constrained areas. Only market participants that have an ability to affect the price are subject to these tests,[78] lessening the likelihood that mitigation will be applied simply when scarcity occurs. In addition, the Midwest ISO's tariff provides for scarcity pricing. A shortage condition in either market allows the Midwest ISO to consider additional supply sources (such as offers from the emergency range of generators) that are available only in these emergency conditions. It may also trigger a shortage pricing mechanism which administratively establishes the highest accepted offer at the $1,000/MWh safety-net level. Therefore, the Midwest ISO mitigation plan is not expected to harm the development of Day 2 markets by penalizing actions that may be associated with genuine scarcity, and thus by discouraging generators from participating in the market.

[77] 394 F.3d 964 (D.C. Cir. 2005).

[78] Those in a BCA can affect the constraint and thereby affect the market price, those in an NCA are within a constrained area where there is a pivotal supplier.

83. In response to Coalition MTC and the Midwest TDUs' request for clarification of certain implementation terms,[79] we interpret the IMM's intent to be mitigation of all resources owned by a supplier in the same BCA or NCA. We direct the IMM, as part of the tariff filing we order below, to clarify this aspect of the proposal. We further direct the IMM to provide a step-by-step illustration of how the IMM will be determining the universe of generators subject to safety-net plan mitigation in "the same BCA," recognizing the area subject to BCA mitigation shifts without notice to market participants.

84. We do not agree with Coalition MTC and the Midwest TDUs' proposal to require a seller's units to be put on the watch list "automatically" after the first infraction. The purpose of the proposal is to determine which suppliers show a pattern of behavior that requires up to seven days of mitigation. That pattern of behavior is established with the second violation of the conduct and impact thresholds within a set period. However, we note that the IMM has not established the set period, saying "recently (e.g. prior 90 days)." The period during which the IMM will screen for multiple violations of the conduct and impact thresholds (and thus the implementation of mitigation for any violations of the conduct test in the seven-day period) must be clearly stated in the tariff language filed. We will accept a 90-day period. We agree that applying the mitigation for up to one week, at the IMM's discretion, affords too much discretion, and direct the IMM to apply mitigation for all violations of the conduct test by the supplier (as discussed above) during the seven days after its second (or greater) violation of both the conduct and impact tests during the set period. Thus, there will be no need for OMOI review of discretion exercised by the IMM in adopting the number of days of mitigation during that period.

85. We require the Midwest ISO to adopt and implement the safety-net plan, as amended herein, effective April 1, 2005. The Midwest ISO must make a filing within 60 days of the date of this order to include the safety-net plan in the TEMT.

86. We recognize the IMM's proposed timeline must allow time for a stakeholder process, an evaluation of actual market results in the first quarter of energy market operations, and avoid an implementation start date in a peak period. Further, we recognize that the software issues associated with AMP implementation explained by the IMM must be addressed at a sensitive time for the Midwest ISO energy markets when these markets are in the first critical months of operation. At the same time, we must balance the IMM's imperatives with the Commission's objective to have an AMP program operational as soon as possible. Therefore, we require the IMM and the

[79] Midwest TDUs Protest at 7.

Midwest ISO to make an informational filing that includes a detailed report on the status of the software needed to implement AMP, a target completion date, and a best estimate by IMM and the Midwest ISO of the earliest date it could file an AMP proposal at the Commission. We will require that informational filing be filed at the Commission no later than June 1, 2005. We request that the IMM and the Midwest ISO be prepared to address questions on this filing at the proposed July 15 presentation.

2. Mitigation for Entities Eligible for Expanded Congestion Hedge in Narrow Constrained Areas

a. Background

87. The TEMT II Order required penalties for deviations from day-ahead scheduling on parties receiving the expanded congestion coverage as a means to prevent such parties from over-scheduling day-ahead to create congestion while being fully hedged against that congestion and then changing their positions in real-time.[80] The TEMT II Rehearing Order eliminated the penalty, in recognition that the penalty could be too restrictive and thus inhibit efficient changes in the day-ahead schedule. That order required the IMM to file a monitoring plan to detect patterns of inefficient scheduling and associated mitigation measures, such as the refund of congestion relief payments.[81]

b. The IMM's Compliance Filing

88. The IMM proposes to institute a conduct screen to detect participants that are seeking congestion hedge payments for schedules they would not rationally implement today. The IMM proposes to screen for uneconomic schedules in the day-ahead market using the uneconomic production thresholds approved in Module D, i.e., the screen will identify any generating unit scheduled in the day-ahead market when the average LMP at the generator's location is less than 50 percent of the unit's reference level, including start-up and no-load costs. If the Commission believes a mitigation measure is warranted, the IMM proposes that the congestion hedge payments associated with the schedule be withheld for any day when this uneconomic production test is satisfied.

89. The IMM also proposes a screen to determine whether the total day-ahead schedules of the holders of transitional congestion hedges exceed the physical import capability of the NCA. The IMM states that to the extent that holders of the transitional

[80] *See* TEMT II Order at P 92.

[81] *See* TEMT II Rehearing Order at P 116.

congestion hedges schedule amounts that exceed the physical capability of the system, the holders of the hedges will receive a windfall and the uplift borne by others will be inflated. The IMM proposes to screen and report to the Commission the quantities of schedules and associated uplift costs that correspond to physically infeasible schedules. If the monitoring reveals a significant concern, the IMM will provide recommendations to the Commission for addressing the concern by modifying the provision.

90. The IMM states that the screening and mitigation proposals do not address the real-time dispatch of resources based on his belief that holders of the transitional congestion hedges cannot increase their congestion payments by altering their real-time output from the amount scheduled in the day-ahead market.

c. Discussion

91. While we find the IMM's proposal for monitoring and mitigating inefficient day-ahead scheduling and aggregate day-ahead schedules to be in compliance with the requirements of the TEMT II Rehearing Order,[82] we believe the IMM misapprehends our concern with real-time dispatch of units receiving the congestion relief hedge. Our concern is that holders of congestion relief hedges, since they have a cost-less hedge without limit on all day-ahead energy, will have the incentive to nominate the full hedge on all transmission paths, even when they know they will not use the full amount, since to do so would result in an additional benefit of obtaining revenues from energy sold into the real-time balancing energy market.[83]

92. In the TEMT II Rehearing Order, we agreed with the IMM that a megawatt or percentage deviation penalty would interfere with scheduling the least-cost mix of generation in real time. However, we believe the IMM's statement in its compliance filing that holders of transitional congestion hedges cannot increase their congestion payments by altering their real-time output to be beside the issue. Therefore, we again

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[82] We note that the IMM's role in setting the reference level, as discussed in the IMM Compliance Filing at 9, is to be determined in other Commission proceedings and therefore is subject to revision.

[83] Dr. Hogan outlined this scenario in his testimony, submitted with the TEMT II tariff filing. *See* Prepared Direct Testimony of Dr. William Hogan at 41-44 (Mar. 31, 2005).

direct the IMM to file a monitoring plan, within 60 days of the date of this order, to detect patterns of inefficient scheduling. The Midwest ISO must file the conforming tariff sheets on inefficient day-ahead scheduling and aggregate day-ahead scheduling within 60 days of the date of this order.

E. System Supply Resources, Demand Response Resources, Offer Caps and Emergency Procedures

1. Offer Caps

a. Background

93. The TEMT II Order accepted the Midwest ISO proposal to adopt a $1,000/MWh safety-net bid cap comparable to the caps that apply in the PJM, NYISO and ISO-NE markets.

b. Requests for Rehearing

94. Midwest Municipal Transmission Group states that the premise of Day 2 energy markets is that the public will be advantaged by competition, and that LMP is intended to promote infrastructure investment to improve efficiency and promote competitive markets. Midwest Municipal Transmission Group notes, however, that the Commission permits sellers to charge prices as high as $1,000/MWh in Day 2 LMP markets. Midwest Municipal Transmission Group argues that this amount may be more than ten times, sometimes more than fifteen times, actual energy costs of the last generating unit whose output clears the market, and cannot be justified as just and reasonable.

95. Midwest Municipal Transmission Group states that the $1,000/MWh bid cap is largely adopted from other markets and has no cost justification. While some sellers have protested that the cap is too low, the reality is that in normal, competitive commercial markets no product will sell at amounts far above production costs because buyers will refuse to buy and demand will fall. However, Midwest Municipal Transmission Group notes, electricity markets suffer from weak demand responses. The

nature of the product and factors unique to electricity permit sales at multiples of incremental cost. A high price may be an "incentive," but this does not make such prices just and reasonable.[84] Midwest Municipal Transmission Group concludes that the Commission cannot justify the bid cap as necessary.

c. Discussion

96. We deny rehearing of Midwest Municipal Transmission Group's request for the reasons stated in our previous orders. Our previous orders have already explained why the offer cap is necessary as a safeguard measure and as a proxy for demand bids.[85]

F. Resource Adequacy Requirements

1. General Proposal

a. Background

97. The Commission generally accepted the Midwest ISO's interim resource adequacy proposal in the TEMT II Order on the basis that it will operate as a transition mechanism to ensure that day-to-day reliability needs are met in a way similar to how it is currently done.[86] In addition, the Commission directed the Midwest ISO to work expeditiously toward the filing of a long-term resource adequacy plan. In the TEMT II Order, the Commission also directed the Midwest ISO to make several clarifying changes to Module E, addressing among other things, the effective time period for Module E, its breadth and scope, and the must-offer requirement for designated Network Resources.

98. Several parties filed requests for rehearing of the TEMT II Order. In the TEMT II Rehearing Order, the Commission denied rehearing requests to: delete Module E entirely, set a fixed date for the long-term plan to be filed, clarify Network Resource qualifications, and the Commission declined to mandate a common resource adequacy standard between the Midwest ISO and PJM at Midwest ISO market start-up. The Commission granted requests for clarity about the features of the long-term plan,

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[84] Midwest Municipal Transmission Group Request for Rehearing at 3 (citing *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486 (D.C. Cir. 1984); *City of Detroit v. FPC,* 230 F.2d 810 (D.C. Cir. 1955)).

[85] *See* TEMT II Order at P 380.

[86] *See id.* at P 421-22.

consistency between the Midwest ISO's and PJM's resource adequacy plans, adding the word "applicable" to sections 68.1.2.a and 68.1.2.b, and the Commission's views about Alternative Capacity Resources. In particular, the Commission noted that it was not mandating specific treatment for behind-the-meter resources in the long-term plan. We also note that several features of Module E are discussed in a concurrent order that addresses the Midwest ISO's January 21 compliance filing and requests for rehearing of Compliance Order I.

99. In Compliance Order I, the Commission accepted the Midwest ISO's proposal to file a long-term resource adequacy plan on or about June 6, 2006, accepted clarifications to the requirements for designating Network Resources, and generally accepted the 12 percent default reserve margin. The Commission also directed the Midwest ISO to clarify that the interim plan would sunset upon Commission acceptance of the long-term plan, that the Midwest ISO could not require prior approval before members withdrew from reserve-sharing groups, and redirected the Midwest ISO to file tariff sheets that specify that Demand Response Resources may qualify as Network Resources.

b. Requests for Rehearing

100. Cinergy states that the TEMT II Rehearing Order rejected its request that Module E be stricken in its entirety,[87] and rejected FirstEnergy's request that resource adequacy requirements "should apply to all entities that serve load in the Midwest ISO region, irrespective of whether they are or are not a market participant."[88] With respect to the latter request, according to Cinergy, the Commission apparently believes it unnecessary because resource adequacy requirements "are meant to codify the pre-existing reliability requirements in effect" in the MISO region, such that "[t]he requirements on load-serving entities ... should not be significantly different than they were prior to Module E's implementation."[89] Additionally, Cinergy asserts that the Commission believes that "a non-market participant serving load within the Midwest ISO region is unlikely to be jurisdictional; it thus would be beyond the Commission's authority to hold them to" resource adequacy requirements.[90] Finally, Cinergy argues that "since such non-market

[87] Cinergy Request for Rehearing at 2 (citing TEMT II Rehearing Order at P 337).

[88] *Id.*

[89] *Id.*

[90] *Id.* (citing TEMT II Rehearing Order at P 335).

participants likely would be wholesale customers of an entity that is a market participant acting on their behalf . . . they are differently situated from those who are market participants."[91]

101. Cinergy states that it is concerned with this ruling because the new resource adequacy requirements do not, in fact, preserve existing parities, because jurisdictional parties may face new requirements, but non jurisdictional parties will not. First, the resource adequacy requirement is set to a default annual level of twelve percent in some circumstances.[92] Second, as the Commission stated in denying Cinergy's request, "Module E necessitates discretion in applying the Regional Reliability Organization and state reliability standards in effect – including resolving differences between state and Regional Reliability Organization resource adequacy requirements, and determining standards that apply in the Midwest ISO region."[93]

102. Thus, Cinergy concludes that some market participants may be subjected to resource adequacy requirements that are higher than they currently face, while non-jurisdictional entities will remain subject to whatever historic requirements they have faced. This has the potential to create an unlevel, unduly discriminatory playing field, which would result in market inefficiencies. For example, Cinergy argues that in bidding to serve the load of a member of a cooperative, a market participant will need to factor in the costs of an increased resource adequacy requirement, while a non-jurisdictional entity such as the cooperative itself will not. Thus the market participant, who may have a lower incremental cost of generation, may nonetheless be unable to effectively compete. Cinergy argues that distinguishing between jurisdictional and non-jurisdictional entities in resource adequacy requirements is inefficient and rewards those entities that are not required to meet the minimum requirements established by the Midwest ISO to preserve reliability.

103. Cinergy notes that the Commission has previously exercised its conditioning authority to require non-jurisdictional entities to observe reliability-driven market rules in other markets. It states that in California, the Commission required generators that signed Participating Generator Agreements with the ISO – including non-jurisdictional generators – to offer the ISO all of their capacity in real time during all hours if it was

[91] *Id.*

[92] *Id.* at 2-3 (citing TEMT II Order at P 415).

[93] *Id.* at 3 (citing TEMT II Rehearing Order at P 337).

available and not already scheduled to run through bilateral agreements.[94] Cinergy adds that the Commission explained that this must-offer obligation was to "ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed."[95] Further, Cinergy states that the Commission held that all generators needed to participate in helping to solve the problems in California, and as a result required that:

> as a condition of selling into the ISO markets which are subject to this Commission's exclusive jurisdiction, all sellers that own or control generators located in California, including non-public utility sellers that own or control generators in California, must abide by the same must-offer obligation and the price mitigation plan.[96]

Cinergy notes that the Commission explained that application of this requirement to nonjurisdictional entities in California was justified to ensure that rates for power sales were just and reasonable and to maintain the reliability of ISO-run markets:

> Since transmission constraints are contributing to the problems in California, non-public utility generators should not be able to avail themselves of the use of the public utility ISO-controlled transmission facilities while not committing themselves to help solve the problems that have arisen. Including non-public utility generators in California as part of the mitigation will not only help ensure that jurisdictional rates for power sales are just and reasonable but will also help to maintain the reliability of the interstate grid.[97]

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[94] *See San Diego Gas & Elec. Co.*, 95 FERC ¶ 61,115 at 61,355 (2001).

[95] *Id.*

[96] *Id.* at 61,356.

[97] *Id.*

According to Cinergy, while the Commission had not previously used its jurisdiction over public utility interstate transmission lines to impose requirements on non-public utility generators, it recognized its authority generally to "impose conditions on the use of interstate facilities owned, operated or controlled by public utilities such as the ISO, and on the tariffs under which those public utilities provide service."[98]

104. Cinergy therefore argues that the Commission has the authority to condition use of the Midwest ISO-controlled grid on compliance with standards it sets. It argues that, as was the case in California, the resource adequacy requirement is intended to increase reliability benefits. Moreover, Cinergy alleges that unequal application of these rules will negatively impact market efficiency, discriminate against jurisdictional generation suppliers, and reward suppliers who act inconsistently with the Commission's reliability objectives. The Commission has used its authority in similar circumstances to impose reciprocity requirements to eliminate undue discrimination.[99] Cinergy submits that there are two bases for the Commission to apply its conditioning authority to require compliance with Midwest ISO resource adequacy requirements here: (1) as a condition of taking Commission-jurisdictional transmission service, and (2) as a condition of

[98] *Id.*

[99] In Order No. 888, the Commission required non-public utilities that own, operate or control transmission facilities to provide reciprocal transmission service on comparable terms, as a condition of receiving open access transmission service from a public utility under its OATT. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, Order No. 888, FERC Stats & Regs. ¶ 31,036 at 31,760-61 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh 'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh 'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). The Commission imposed the reciprocal transmission service requirement on non-public utilities to prevent non-open access utilities from taking advantage of the competitive opportunities of open access, while at the same time offering inferior access, or no access at all, over their own facilities. *See Pacific Northwest Generating Coop.*, 78 FERC ¶ 61,018 (1997); *Southern Ill. Power Coop.*, 80 FERC ¶ 61,341 (1997); *Omaha Pub. Power Dist.*, 81 FERC ¶ 61,054 (1997); *Hoosier Energy Rural Electric Coop.*, 81 FERC ¶ 61,153 (1997).

participation in the Commission-jurisdictional Midwest ISO market. In both cases, Cinergy advocates that the Commission impose the resource adequacy requirements on non-jurisdictional load-serving entities for all load served by the load-serving entity, not just the load served through the transaction in question.

c. Discussion

105. We deny rehearing in regard to Cinergy's assertion that the Commission should impose the resource adequacy requirements of Module E on all non-public utility load-serving entities for all load served by the load-serving entity, not just the load served through specific transactions. All entities, non-jurisdictional or jurisdictional, that become market participants, face new requirements as specified by Module E. For example under Module E, market participants must identify and designate Network Resources sufficient to fulfill the resource adequacy requirements applicable where the load is served.[100] All Network Resources also have a must-offer obligation imposed on them in the day-ahead market.[101]

106. We also deny rehearing regarding Cinergy's argument that any differences in resource adequacy requirements would make jurisdictional entities unable to compete, as any differences would result in inefficiencies over the long term. The Commission has consistently stated that the requirements of Module E are not permanent.[102] Because Module E is an interim plan, it is not designed to foster long-term economic efficiencies. Instead, Module E is designed to ensure reliability is maintained during the interim period until a long-term plan is adopted in the Midwest ISO. The Commission approved this interim framework as a reasonable solution from the Midwest ISO because stakeholders could not reach a consensus on the structure of a long-term plan prior to the March 31, 2004 filing,[103] but the Commission found that the benefits of regional market implementation should not be delayed until a long-term plan is constructed. Therefore, we find that arguments stating that long-term and short-term economic inefficiencies are the likely result of the Midwest ISO's interim resource adequacy requirements plan are not consistent with the intent of Module E, and we are not compelled to overturn our

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[100] *See* Module E, section 69, Substitute Original Sheet No. 819.

[101] *Id.* at Original Sheet No. 824.

[102] *See* TEMT II Order at P 421; TEMT II Rehearing Order at P 330; Compliance Order I at P 335.

[103] *See* Testimony of Ronald R. McNamara at 55-56 (Mar. 31, 2004).

acceptance of Module E as just and reasonable and not unduly discriminatory. Moreover, we do not agree that the interim plan will negatively affect reliability, competition, or long-term investment decisions.

107. We continue to find that Module E, as an interim plan, is just and reasonable, and appropriate while a long-term plan for resource adequacy is developed.[104] The Midwest ISO has put forward a plan that largely maintains existing rights, while implementing a new resource adequacy plan on the entire region.[105] For the smaller class of tariff customers that do not become market participants, access to market activities[106] is limited and Module B applies. According to the introduction to Module B, the role of the Midwest ISO is to be the sole point of applications for all energy markets, market activities and all transmission services provided in the Midwest ISO region, and nothing in the tariff related to these activities is intended to alter the existing rights and obligations of the transmission customers, transmission owners, and/or market participants.[107] Therefore, we do not agree with Cinergy that the Commission should direct the Midwest ISO to require compliance with Module E as a condition of taking Commission-jurisdictional transmission service or as a condition of participation in the Midwest ISO market.

108. We find that it is not analogous to compare the requirements of Module E, with the requirements of the California market, which required generators that signed Participating Generator Agreements with the ISO to offer all of their capacity in real time during all hours. In particular, we do not agree that what was ordered for the California markets four years ago is correct for the Midwest ISO at market start-up. In the

[104] "Distribution cooperatives and municipal distribution systems are entities that are specifically exempt from the definition of Load Serving Entity, and thus need not be market participants (as they are customers of Market Participants), yet they still serve load. They would likely not be jurisdictional public utilities, and we could not apply RAR to them. It is not inappropriate, therefore, for the TEMT to exempt non-market participants serving load in the Midwest ISO region from RAR requirements." TEMT II Rehearing Order at P 336.

[105] "The resource adequacy requirements established in this Module E are based upon the pre-existing reliability mechanisms of the states with the Transmission Provider Region…" Module E, Introduction, Substitute First Revised Sheet No. 810.

[106] *See* Module A, section 1.182, Original Sheet No. 95.

[107] *See* Module C, section 38.1, Original Sheet No. 349.

California market of 2001, there were demonstrated reliability issues, such as thin reserve margins, that had to be addressed. By contrast, the Midwest ISO region generally has sufficient reserve margins.[108] Because Midwest ISO reasonably preserves the pre-existing resource adequacy requirements in the region,[109] we find that the California analogy does not apply at this time.[110] We find that imposing new requirements on non-jurisdictional entities at market start-up is unnecessary because we do not find the present Module E results in discriminatory policies. The long-term plan will apply region-wide requirements and its applicability may extend beyond the requirements of Module E. We clarify that we are not prejudging any requirements under development for the long-term resource adequacy plan and we reiterate our directive that the Midwest ISO make expeditious progress toward the filing of the long-term plan.

2. Transmission System Usage

a. Requests for Rehearing

109. Cinergy states that, contrary to the implication of paragraph 335 of the TEMT II Rehearing Order, the supplying party will not necessarily be the load-serving entity in the case of all wholesale purchases by a non-jurisdictional entity. It is not uncommon for a nonjurisdictional load-serving entity to purchase power from a third party on a bilateral basis, but make its own arrangements for use of the transmission system. It is not clear to Cinergy that "transmission customer" status equates to "market participant" status in the context of the resource adequacy requirement. Cinergy advocates that the Commission condition use of the Midwest ISO-controlled grid on voluntary submission to the requirements of Module E. It argues that those who benefit from use of the grid should make fair contribution to measures intended to preserve its reliability.[111] Cinergy states

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[108] *See* Testimony of Ronald R. McNamara at 58 (Mar. 31, 2004). *See also* Potomac Economics, *2003 State of the Market Report* at 12, *available at* http://www.potomaceconomics.com/midwest/2003%20MISO%20SOM_Final%20Full%20Text%20Report.pdf.

[109] *See Module E Implementation, Frequently Asked Questions* at 5, *available at* http://www.midwestiso.org/plan_inter/documents/Resource_Adequacy/FAQ%20Follow%20On_03_23_05.pdf (updated Mar. 23, 2005).

[110] *See* TEMT II Order at P 421.

[111] Cinergy Request for Rehearing at 6 (citing *San Diego Gas & Electric Co.*, 95 FERC ¶ 61,115 (2001)).

that this may be accomplished by amending the definition of "market participant" to include transmission customers, or by determining that a non-jurisdictional transmission customer will be deemed a market participant for purposes of applying Module E.

b. <u>Discussion</u>

110. We deny rehearing with regard to modification of the term Market Participant or conditional use of the Midwest ISO grid. We clarify that those tariff customers that do not become market participants, but instead operate as the defined term Transmission Customers, have different rights and responsibilities under the TEMT.[112] Accordingly, we clarify that we do not view a market participant and a transmission customer as having the same rights and responsibilities in regard to Module E.[113]

111. Furthermore, customers receiving transmission service under Module B of the TEMT are generally only entitled to use point-to-point and network integration transmission service (network service).[114] According to the tariff, customers using network service have a right to firm transmission service over the transmission system to the network customer for the delivery of capacity and energy from its designated Network Resources to its Network Loads.[115] We find that where the TEMT uses the defined term "Network Resource(s)," there are corresponding requirements as defined in

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[112] A Transmission Customer is "[a]ny Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive Transmission Service under Module B of this Tariff. This term is used in Module A, Common Tariff Provisions to include customers receiving Transmission Service under Module B of this Tariff." Module A, section 1.317, Original Sheet No. 132.

[113] A Market Participant is "[a]An entity that (i) has successfully completed the registration process with the Transmission Provider and is qualified by the Transmission Provider as a Market Participant, (ii) is financially responsible to the Transmission Provider for all of its Market Activities and obligations, and (iii) has demonstrated the capability to participate in its relevant Market Activities." Module A, section 1.184, Original Sheet No. 95.

[114] *See* Module B, Introduction, Original Sheet No. 222.

[115] *Id.* at section 28.3, Original Sheet No. 298.

Module E.[116] In limited cases where transmission customers are not using Network Resources to serve their native network load, there would likely still be reserve responsibilities imposed on them by the applicable state or regional reliability organization. In addition, it is possible that the service agreement governing a point-to-point transaction would have an implicit reserve obligation associated with it.[117] In states with no reserve margin requirement, a default 12 percent reserve margin applies. Therefore, we find that the overwhelming majority of transactions conducted in the Midwest ISO market have corresponding resource adequacy requirements implicitly and explicitly tied to them. Therefore, no modification of the term "Market Participant" is needed.

3. Applicability of Module E

a. Requests for Rehearing

112. Cinergy states that the Midwest ISO has identified GFA parties as "Market Participants" and determined that GFA parties who over-schedule generation will receive compensation from Midwest ISO spot markets, even if they are "carved out" of the market.[118] Similar provisions pertain to a shortage of generation relative to load.[119] Thus, Cinergy argues that even non-jurisdictional entities will be market participants to the extent that they avail themselves of the Midwest ISO markets for purposes of resolving such imbalances. Cinergy asks the Commission to affirm that such market participant status will trigger applicability of Module E. It also asks for a determination that once a party is a market participant, service to its entire load within the Midwest ISO footprint should be subject to Module E.

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[116] *See* Module E, section 69.1.2.b, Substitute Original Sheet No. 821.

[117] *See* TEMT Attachment A, Original Sheet Nos. 1051-61.

[118] Cinergy Request for Rehearing at 6 (citing Compliance Filing of Midwest Independent Transmission System Operator, Inc., at 6-8 (Nov. 15, 2005) ("a Market Participant with a carved-out GFA schedule that generates in excess of load will be appropriately compensated at the Real-Time LMP for the excess generation.")).

[119] *Id.*

113. Cinergy notes that Hoosier, in its protest to a prior Midwest ISO compliance filing on the same topic, has argued, in effect, that subjecting it to energy imbalance costs from the Midwest ISO market may subject it to trapped costs, because the Commission is without jurisdiction to require Hoosier's customers to reimburse it for such costs.[120] Cinergy recommends that the Commission carefully consider whether this argument withstands scrutiny. The Commission has held in other contexts that the customers of a cooperative are its members, with the result that there are no affiliate abuse concerns.[121] In that case, the Commission explained, in holding that no code of conduct was required in connection with market-based rate authority, that:

> [T]here is a distinction between affiliate abuse protection for cooperatives and investor-owned utilities. The concern that a utility can transfer benefits from captive ratepayers to shareholders is not present in the case of a cooperative because *the rate payers are owners of the cooperative; thus, any profits earned will inure to the benefit of the ratepayer*.[122]

Cinergy alleges that Hoosier has not explained how Midwest ISO-associated costs will be treated differently, within the cooperative structure, than the benefits discussed in *Wolverine*, i.e., whether such costs also will inure to its members. It is not clear, therefore, why any lack of Commission jurisdiction to prevent trapped costs will necessarily result in trapped costs.[123]

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[120] Cinergy Request for Rehearing at 7 (citing Protest of Hoosier Energy Rural Electric Cooperative, Inc. at 5 (Nov. 8, 2004)).

[121] *See, e.g., Wolverine Power Supply Cooperative, Inc.*, 94 FERC ¶ 61,178 (2001).

[122] *Id.* at 61,616 (quoting *Wolverine Power Supply Cooperative, Inc.*, 93 FERC ¶ 61,328 at 62,119 (2000) (emphasis added)).

[123] Hoosier also argues that it should be allowed to procure imbalances under its existing GFAs, and cites some language in the GFA Order that, it claims, supports its position. Hoosier Protest at 4. However, the GFA Order did not purport to modify any GFA to require such provision of imbalance service, nor was there record evidence supporting any such modification. This question therefore is one of individual interpretation of the rights conferred under each GFA.

114. Cinergy is concerned that it is not sufficiently clear when a non-jurisdictional entity will be deemed a market participant for purposes of applying Module E. For example, the entity may only transact in the Midwest ISO market, or take TEMT transmission service, during periods of peak demand, and otherwise transact under GFAs. The Commission should affirm that market participant status is not ephemeral, to be arbitraged at the will of a non-jurisdictional entity. Nor is it clear, for example, how an annualized resource adequacy requirement could be applied only on a "spot" basis. Any entity that wishes to transact in the Commission-jurisdictional marketplace or avail itself of Commission-jurisdictional transmission service at any time during a calendar year should be required, as a condition of such participation, to demonstrate that it has met the minimum Midwest ISO requirements for resource adequacy, and has otherwise comported with the requirements of Module E, for that year. Moreover, Cinergy argues, this requirement should pertain to all load-serving activities of the non-jurisdictional entity where the entity would be deemed a load-serving entity, not just those transactions that involve use of Commission-jurisdictional services.

115. This, Cinergy states, preserves the voluntary nature of participation that the Commission emphasized in the TEMT II Rehearing Order,[124] but eliminates the potential for "cherry-picking" market opportunities, helps to level the playing field and eliminate inefficiencies, and advances the Commission's goal of preserving reliability through a resource adequacy requirement. Moreover, Cinergy says, it is consistent with the Commission's steps to condition participation in California markets on offering generation into those markets in all hours available (i.e., not just in hours when the non-jurisdictional entity is otherwise participating in the market).[125] In that case, by definition, the requirement applied only to available generation not otherwise being offered into the market, since such a "must offer" requirement would be meaningless for generation already being offered into the market. Similarly, an otherwise non-jurisdictional entity wishing to avail itself of Commission jurisdictional services in the Midwest ISO market should be required to do its fair share, over the course of the calendar year, to meet the Commission's reliability objectives.

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[124] Cinergy Request for Rehearing at 9 (citing TEMT II Rehearing Order at P 334).

[125] *Id.* (citing *San Diego Gas & Electric Co.*, 95 FERC ¶ 61,115 (2001)).

b. Discussion

116. Consistent with our previous discussion, we clarify that "Market Participant" is a defined tariff term that carries with it commensurate responsibilities. We find that a Market Participant is an entity that has submitted a Market Participant Application,[126] executed the Market Participant Agreement,[127] and been qualified by the Midwest ISO as capable of participating in all relevant Market Activities.[128] Any entity that becomes a market participant, including parties with carved-out GFAs, must comply with all requirements, including those listed in Module E. This issue is discussed further in a concurrent order on GFAs.[129] Briefly, that order allows any entity with a carved-out GFA that had to seek market participant status solely to provide service under the carved-out GFA, to fulfill the service specified in the agreement without becoming a qualified market participant.

117. To further clarify, we also anticipate that several small jurisdictional or non-jurisdictional entities may seek to amalgamate their resources into one entity that conducts market activities in the Midwest ISO as the market participant. Although several entities may serve load at the local level, only the market participant is responsible for complying with all tariff requirements. We find that this is an acceptable arrangement because it is only possible in very limited situations and it allows the economic efficiencies gained by regional markets to extend to all customer classes regardless of their size.

118. The issue of Hoosier's ability to recover trapped energy imbalance costs from its customers is addressed in the order on GFAs that the Commission is issuing as a companion to this order.

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[126] *See* Module A, section 1.187, Substitute Original Sheet No. 96.

[127] *See id.* at section 1.185, Original Sheet No. 96.

[128] *See id.* at section 1.182, Original Sheet No. 95.

[129] *See Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,042 (2005).

4. <u>The Must-Offer Requirement</u>

a. <u>Background</u>

119. The Midwest ISO proposed that designated Network Resources must submit a self-schedule or offer in the day-ahead market and the first Reliability Assessment Commitment, except where the resource is unavailable due to an outage. In the TEMT II Order, the Commission accepted this requirement, noting that current Network Resources are in the rate base and thus receiving fixed cost payments.[130] The Midwest ISO further clarified in a compliance filing that existing Network Resources are allowed to continue as such in the Midwest market.[131] The Commission conditionally accepted these clarifications to the requirements for designation of a Network Resource in the Compliance Order I and ordered further clarifications.[132]

b. <u>Requests for Rehearing</u>

120. The Midwest TDUs state that the TEMT II Order correctly accepted the Midwest ISO's proposal to require Designated Network Resources (DNR) to bid into the day-ahead market. In the TEMT Rehearing Order, the Commission equivocated on the requirement by accepting Cinergy's proposed limitation "to require only the load-serving entity's next-day forecast load plus its operating reserve requirement to be bid into the day-ahead market."[133] The Midwest TDUs request rehearing of the Commission's change of position. They argue that limiting the must-offer requirement unreasonably increases risks of consumer harm.

121. The must-offer requirement plays a critical role in ensuring reliability in the Midwest, according to the Midwest TDUs. Midwest ISO testimony supporting the requirement stated that it "is necessary to ensure that DNRs are available to serve load in times where reliability may be threatened."[134] Indeed, in rejecting Cinergy's request to

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[130] *See* TEMT II Order at P 410-11.

[131] *See* Original Sheet No. 823B.

[132] *See* Compliance Order I at P 292.

[133] Midwest TDUs Request for Rehearing at 2 (citing TEMT II Rehearing Order at P 345).

[134] Prepared Direct Testimony of Ronald R. McNamara at 60 (Mar. 31, 2004).

limit the must-offer requirement to just the RAC process, the Commission correctly concluded that the “day-ahead must-offer will help to ensure supplies are sufficient to meet load and to avoid excessive prices from shortages.”[135] The Midwest TDUs allege that the Commission undermines this reliability role by limiting the must-offer requirement to just the daily peak load forecast plus operating reserves. Among other things, it fails to account for the fact that forecasting errors and unscheduled outages occur and thus increases reliability risks to consumers.

122. The Midwest TDUs state that, whether through poor forecasting or intentional gaming, Midwest markets could well come up short, thus triggering the $1,000/MWh cap if operating reserves are deployed. They note that if some or all load-serving entities incorrectly estimate their loads, everyone would pay $1,000/MWh. The Midwest TDUs argue that the Commission's change could also invite artificial shortages and application of scarcity prices when no real scarcity exists. They state that these concerns are heightened in constrained, concentrated load pockets, such as WUMS, where mistaken forecasts or gaming by a dominant, vertically integrated utility could artificially raise prices. The Midwest TDUs urge the Commission not to dilute the must-offer requirement that has already been road-tested in PJM.[136]

123. The Midwest TDUs also argue that the limitation could also prove inefficient and costly. If a load-serving entity need bid only a portion, not all, of its DNRs (especially on low-load or shoulder days), it could refrain from bidding its more economic units (including by submitting bids that do not reflect marginal costs) and instead bid more expensive units.[137] Even without a shortage, the Midwest TDUs argue, resulting clearing prices would be higher, resource commitment would be misinformed, and efficient, economic dispatch of the whole system would be frustrated.

[135] Midwest TDUs Request for Rehearing at 2 (citing TEMT II Rehearing Order at P 346).

[136] PJM Tariff, Attachment K Appendix § 1.10.IA(d); PJM Operating Agreement Sch. 1 § 1.10.IA(d).

[137] To the extent a unit is subject to mitigation thresholds, Module D’s conduct thresholds, especially in BCAs, give bidders ample room to inflate bids by the lesser of 300 percent or $100/MWh with no fear of IMM surveillance or intervention.

124. Finally, the Midwest TDUs argue that the limitation on the must-offer requirement cannot be justified on grounds that it interferes with bidding into other markets or otherwise leaves generators uncompensated. DNRs should already be committed to load-serving entity loads, not used to make firm sales into adjacent markets. Further, the Midwest ISO DNRs should be receiving capacity payments, as the TEMT II Rehearing Order recognizes.[138] That such a payment comes through rate base recovery or a bilateral contract, rather than a PJM-style installed capacity (ICAP) market, should not matter. Indeed, the Midwest's mechanisms are more likely to provide an assured, long-term revenue stream to DNRs than ISO/RTO-operated ICAP markets.

c. Discussion

125. We disagree with the Midwest TDUs' contention that the TEMT II Rehearing Order accepted a limitation on the day-ahead must-offer requirement. The relevant paragraph stated that we denied rehearing on Cinergy's request for a limitation.[139] The TEMT II Rehearing Order did not propose any changes to section 39.2.5.a that would require market participants to provide offers for their full megawatt range of operable capacity designated as a Network Resource.

G. Other Tariff Issues

1. Miscellaneous Module A Issues

126. The Midwest ISO proposes a series of revised definitions in Module A, in response to Commission directives in the TEMT II Rehearing Order. We accept those revisions, except for those noted below.

127. The Midwest ISO proposes to add a definition for Dynamic Scheduling, in response to a proposal by Cinergy in paragraph 401 of the TEMT II Rehearing Order. The proposed definition is as follows:

> **Dynamic Scheduling** Bilateral Transaction Schedules for which the Market Participant has put in place real-time and interval metering facilities approved by the Transmission

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[138] Midwest TDUs Request for Rehearing at 3 (citing TEMT II Rehearing Order at P 350).

[139] *See* TEMT II Rehearing Order at P 345 (denying Cinergy's rehearing request, where Cinergy favored revising the must-offer requirement to limit its applicability).

> Provider where Resources are supplying Energy to Load on a real-time basis and the supply is being effected through the use of Scheduled Interchange in the area control equation.

128. Manitoba Hydro contends that the proposed definition of Dynamic Scheduling would not allow for dynamic scheduling of loads external to the Midwest ISO region, such as Manitoba, since "Load" is defined to be either an end-user of Energy or the amount of Energy consumed by the end user in the Midwest ISO region. Therefore, we require the Midwest ISO to replace the term "Load" with "load." The Midwest ISO, in its Answer, agrees to make this revision. Accordingly, we direct the Midwest ISO to file this change within 60 days of the date of this order.

129. The Midwest ISO did not respond to some of the revisions to definitions that Cinergy proposed in its request for rehearing of the TEMT II Order.[140] We require the Midwest ISO to revise, as indicated in brackets, section 1.2:

> **Actual Interchange** The Interchange value, in MW, [delivered or] received by a Balancing Authority during an Hour.

With respect to the proposed revision to section 1.209 (Net Actual Interchange), we will not require this change since the current definition accurately defines interchange to be between physically adjacent Control Areas.

2. Miscellaneous Module B Issues

130. The Midwest ISO proposes a number of revisions to provisions in Module B, in response to Commission directives in the TEMT II Rehearing Order. The Midwest ISO explains, in response to a Commission requirement in the TEMT II Rehearing Order for a change to a 20-minute deadline, that the 30-minute deadline for submission of firm and non-firm schedules is necessary to maintain the reliable operation of the energy markets since this time interval is needed to ensure all external schedules are treated the same as internal resource changes and to ensure that the schedules are included in the dispatch during the ramp period of schedule, which can last up to 20 minutes and can not be timely acted upon by all parties from which approval is required. We accept this explanation and therefore no change is required to the TEMT.

[140] *See* TEMT II Rehearing Order at P 406.

3. Miscellaneous Module C Issues

131. The Midwest ISO proposes revisions to Module C provisions, in response to Commission directives in the TEMT II Rehearing Order. With the exception of certain provisions discussed below, we accept those revisions.

132. The TEMT II Rehearing Order required the Midwest ISO to insert a provision that states that all sales of energy and ancillary services into the energy markets from generation resources located in Canada, and all market participants' purchases from the energy markets to serve load in Canada, shall be deemed to have a point of delivery at the Canada/United States border.[141] In its compliance filing, the Midwest ISO inserted added the requested language into section 38.2.5.g, with the exception of inserting the terms "Point-of-Receipt or Point-of-Delivery" instead of "point of delivery."

133. Manitoba Hydro asserts that the proposed revision of "Point-of-Receipt or Point-of-Delivery" in section 38.2.5.g would, by the terms of the definitions, only apply to Module B service, would be restricted to transmission facilities owned or controlled by entities that have operational control to the Transmission Provider and refer to transmission service transactions and not energy purchases and sales in the energy market.[142] For these reasons, Manitoba Hydro recommends that "point of delivery," referring to the point at which legal title is transferred, be substituted for these terms. Manitoba Hydro also contends that the Midwest ISO's revision to the definition of External Bilateral Transaction Schedule, which includes Point-of-Receipt and Point-of-Delivery in the definition, conflict with Manitoba Hydro's proposed change and that the last sentence – "When External Transaction Receipt Points and the External Transaction Delivery Points are on opposite sides of the U.S./Canada boundary, the transaction shall be deemed to take place at the U.S./Canada boundary" – should be deleted.

134. In its Answer, the Midwest ISO proposes to revise the definitions of Point-of-Receipt and Point-of-Delivery to include a reference to Module C and to eliminate the sentence requested by Manitoba Hydro from the definition of External Bilateral Transaction Schedule.

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[141] TEMT II Rehearing Order at P 493.

[142] We note that Manitoba Hydro's protest refers to section 32.2.2.g. The Midwest ISO actually proposed to make this change to section 38.2.5.g on sheet 396. Since this section does not contain the relevant language, we assume Manitoba Hydro is referring to section 38.2.5.g.

135. We agree with Manitoba Hydro that our directive in the TEMT II Rehearing Order was to require the term “point of delivery,” thereby avoiding the confusion with the definitions of terms such as Point-of-Receipt or Point-of-Delivery that reference points on the Transmission System and therefore only refer to points under the control of the Midwest ISO. Therefore, we will require this change to section 38.2.5.g. The Midwest ISO’s Answer, to retain the terms Point-of-Receipt and Point-of-Delivery, perpetuates the confusion with these terms.

136. Nonetheless, we accept the Midwest ISO’s proposed additional reference to Module C in the definitions of Point-of-Delivery and Point-of-Receipt since it appropriately expands the applicability of the definition to energy market transactions. We also accept the deletion of the second sentence of the definition of External Bilateral Transaction Schedule since the U.S./Canada border issue has been clarified in the Midwest ISO revision to section 38.2.5.g, sheet 396, in its compliance filing. In addition to this revision, we also direct that “boarder” be changed to “border” in section 38.2.5.g.

137. The TEMT II Rehearing Order required the Midwest ISO to modify the definition of External Bilateral Transaction Schedule to indicate an electric or physical location within the Transmission Provider Region or electrically adjacent External Control Areas, or alternatively, to specify why this would not be an appropriate approach. In response, the Midwest ISO revised the definition of External Transaction Delivery Point to remove the term Commercial Node and replace it with “location,” thereby allowing for these transactions to occur outside the Midwest ISO region and consistent with the definition for External Transaction Receipt Point.

138. Manitoba Hydro argues that the Midwest ISO did not modify the definition of External Bilateral Transaction Schedule and therefore the term “Commercial Node” should be replaced by “External Transaction Receipt Point or External Transaction Delivery Point” in section 40.2.6.b, the section governing Dispatchable External Bilateral Transaction Schedules. This change, according to Manitoba Hydro, will make this provision consistent with the revisions made by the Midwest ISO to delete “Commercial Node” from the definitions of External Transaction Receipt Point or External Transaction Delivery Point, and thereby recognize that the Transmission Provider will be sending dispatch instructions for external transactions at the External Transaction Receipt Point or External Transaction Delivery Point rather than an on-system Commercial Node.

139. In its Answer, the Midwest ISO agrees to Manitoba Hydro's revision, but notes that "Node" and "Bus" are still defined "within" and "in" the Transmission Provider Region, respectively. Therefore, Midwest ISO proposes to redefine these terms as follows:

> **Bus:** An electrical location modeled in the Network Model and used by the State Estimator (e.g., a sub-station electrical bus).
>
> **Node:** A physical location represented in the Network Model.

The changes comply with our requirements and address the issues associated with service for Manitoba Hydro. Therefore, we direct the Midwest ISO to make these revisions within 60 days of the date of this order

140. In its compliance filing, the Midwest ISO added the clause "using Point-to-Point Transmission Service" to section 38.2.5.f, in response to Cinergy's request that the section be revised to specify that a market participant can utilize Point-to-Point Transmission Service to deliver to resources located outside the Transmission Provider Region to a proxy bus at the electrical boundaries of the Transmission Provider Region.

141. Manitoba Hydro argues that all types of transmission service, not just point-to-point service, should be able to access resources located outside of the Midwest ISO region and that the Business Practices Manual permits the use of grandfathered service and network service. The Midwest ISO, in its Answer, agrees with Manitoba Hydro's revision and proposes to add language stating that delivery outside the Midwest ISO region can be accomplished through any of the three mentioned options: point-to-point transmission service; grandfathered service; or, where there is an applicable coordination agreement, network service. We agree with these changes as being an accurate and complete description of the service eligible for delivery of resources outside the Midwest ISO region, and we direct the Midwest ISO to propose revisions within 60 days of the date of this order.

142. Paragraph 525 of the TEMT II Rehearing Order required the Midwest ISO to respond to a series of clarifications and revisions Cinegy proposed. We accept the Midwest ISO's responses, unless indicated otherwise below. While the Midwest ISO did not explain its rejection of several of the Cinergy revisions, we find the proposed tariff provisions are acceptable and do not require revision.

143. The Midwest ISO's compliance filing transmittal letter states it revised subsection (j) of section 38.1.1 to replace "Determine" with "Implement and maintain." We note that the Midwest ISO made the revision, incorrectly, to subsection (b), and the numbering of this section has been revised so that the original subsections (i) through (o) on sheet 352 have been revised to subsections (a) through (g) in the Midwest ISO compliance filing. We direct the Midwest ISO to revise the lettering of the subsections to be consistent with the original numbering.

144. Section 38.2.6, in relevant part, states the following:

> The day prior to the Operating Day, Market Participants that are [load-serving entities] or purchase on behalf of [load-serving entities] shall perform the following functions:
>
> i. Provide generation commitment to the Transmission Provider;
> ii. Work in conjunction with the Balancing Authorities and Transmission Operators to implement Load Shedding during Emergency conditions.

In response to Cinergy's request to replace the word "implement" with "plan" in subsection (ii), the Midwest ISO states that this revision does not correctly reflect such practices. We direct the Midwest ISO, as part of its compliance filing, to clarify how it is implementing Load Shedding the day before the Operating Day. Our review of the Load Shedding and related Emergency provisions indicate that the implementation of these activities is restricted to the Operating Day.

145. In the TEMT II Rehearing Order, the Commission required that standing orders be accommodated for a market participant's default purchase quantity in section 39.2.2.b.i. The Midwest ISO responds that such a provision would require changes to its software and computer systems and cannot be accommodated prior to March 1, 2005. We direct the Midwest ISO to submit a report within 60 days of this order that indicates its expected date of implementation for this feature and its progress.

146. The TEMT II Rehearing Order required the Midwest ISO to respond to a number of clarification requests and proposed revisions of Cinergy related to FTR procedures. The Midwest ISO responded that it is currently implementing these provisions in the initial FTR allocation process, and therefore would not be responding at this time. Since the initial FTR allocation has been completed, we direct the Midwest ISO to respond to these issues, that encompass sections 43.2.3 through section 47 in paragraph 525 in the TEMT II Rehearing Order within 60 days of this order.

147. We note that the Midwest ISO filing had no response or tariff revisions for Commission directives in paragraphs 558, 560 and 561 of the TEMT II Rehearing Order. We direct the Midwest ISO to comply with those directives within 60 days of this order.

a. Generator Outages

i. Background

148. Section 38.2.5.h of the TEMT, approved in the TEMT II Order, states that the Midwest ISO shall coordinate Generator Planned Outages. The section requires market participants to submit their outage schedules to the Midwest ISO. It also provides that the Midwest ISO shall inform market participants if their schedules will have a material impact on the reliability of the Midwest ISO region, and reschedule outages when faced with a documented reasonable expectation of an emergency. Market participants with rescheduled outages will be compensated for reasonable and explicit additional costs, excluding opportunity costs. Generator rescheduling procedures will be applied non-discriminatorily and filed at the Commission.

149. The TEMT II Rehearing Order noted that section 38.2.5.h provides the Midwest ISO will reschedule generator outages after it has a documented, reasonable expectation of an emergency. An emergency, per section 1.80, is: (1) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (2) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (3) a condition that requires implementation of emergency procedures as defined in the TEMT and the Business Practices Manuals. The TEMT II Rehearing Order considered this listing of conditions for outage rescheduling to be clear and comprehensive criteria and recognized the Midwest ISO needs to have the ability to act quickly and effectively to respond to reliability issues, and should not be constrained by compliance filings, notice requirements and stakeholder reviews for situations that may require split-second decisions. Accordingly, the TEMT II Rehearing Order denied Cinergy's requests for rehearing and stated that Cinergy should bring issues to the Commission's attention, either as filings or complaints, after the emergency situations have been addressed. The order further clarified that such filings would be the appropriate venue to address Cinergy's concerns that it may not receive full compensation for outage rescheduling.[143]

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[143] *See* TEMT II Rehearing Order at P 466.

ii. <u>Requests for Rehearing</u>

150. Cinergy argues that the TEMT II Rehearing Order denied its request for rehearing with respect to several aspects of the Midwest ISO's process for rescheduling of generator planned outages. Among other things, Cinergy argued that it should have a right to challenge outage rescheduling because "[o]utage scheduling takes into account many factors, such as environmental emission limitations."[144] Cinergy asks the Commission to confirm that the Midwest ISO may not reschedule a planned outage if continued operation of a plant during the outage period would contravene applicable laws, regulations, or court or agency orders. Cinergy states that the TEMT II Order confirmed that the Midwest ISO's system supply resource designations cannot contravene applicable law,[145] and argues that the same reasoning should apply here – when a unit is removed from service to comply with applicable law, the Midwest ISO should not be able to require it to stay in service.

151. Cinergy argues that the TEMT II Rehearing Order demonstrates that these two issues should be treated in parallel. There, the Commission agreed with Cinergy that "market participants may wish to retire a unit or take a unit out of service temporarily for environmental or other valid reasons. The SSR program would interfere with such decisions generally only when those decisions create a short-term reliability problem."[146] Cinergy further notes that the TEMT II Rehearing Order found that "SSR designations cannot be imposed if continued operations of a plant would be contrary to applicable law, regulations, court or agency orders, such as a settlement with an environmental agency or a consent decree approved by a court,"[147] and that "generators must not be required to operate in violation of other applicable restrictions on their operations."[148] However, there is no parallel finding with respect to generator outages.

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[144] Cinergy Request for Rehearing at 41 (Sept. 7, 2004).

[145] *Id.* at 10 (citing TEMT II Rehearing Order at P 291).

[146] *Id.*

[147] *Id.*

[148] *Id.* at 10-11 (quoting TEMT II Order at P 292). Cinergy notes that the Commission did not modify the TEMT to make this affirmation with respect to SSR. *Id.* (citing TEMT II Rehearing Order at P 292).

iii. Discussion

152. As we stated with respect to the effect of the System Supply Resources program on retiring generating units, we do not anticipate that the Midwest ISO will use its generator outage scheduling capability to interfere with generator outage schedules unless it foresees that those schedules will likely create a reliability problem.[149] We agree with Cinergy, however, that the Midwest ISO may not reschedule planned generator outages if doing so would contravene applicable laws, regulations, court or agency orders. The Midwest ISO is therefore instructed to clarify section 38.2.5.h to include this exception to its generator outage scheduling authority.

b. Applicability of Market-Based Rate Authority To Market Participation

i. Background

153. In its request for rehearing of the TEMT II Order, WEPCO requested clarification that it can participate in the energy markets without first seeking broader market-based rate authority. WEPCO explained that it only had market-based rate authority for energy sales outside WUMS[150] and that energy sales within WUMS were made pursuant to its cost-based sales tariff. In the TEMT II Rehearing Order, the Commission stated that to retain market-based rate authority, WEPCO must follow the Commission's review procedures regarding market-based rate authority (*i.e.*, three-year market-based rate review), and to request market-based rate authority in geographical areas previously excluded WEPCO must file an application with the Commission seeking to amend its existing market-based rate tariff.[151] In that order, the Commission also noted that the Midwest ISO-wide market will not be considered as the default geographic market until such time as the Midwest ISO becomes a single market and performs functions such as single central commitment and dispatch with Commission-approved market monitoring and mitigation.[152] The Commission stated it will make such a determination in a separate order.

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[149] *See* TEMT II Rehearing Order at P 291.

[150] *See Wisconsin Electric Power Company*, 82 FERC ¶ 61,067 (1998).

[151] *See AEP Power Marketing, Inc., et al.*, 107 FERC ¶ 61,018 (2004).

[152] *See id.* at P 188.

ii. Requests for Rehearing

154. WEPCO requests clarification, or in the alternative rehearing, with regard to the Commission's response to its request for rehearing. WEPCO states that while the Commission clarified the circumstances under which WEPCO could apply for authority to charge market-based rates in the future, the TEMT II Rehearing Order did not address whether WEPCO would be in violation of its cost-based sales tariff if it offered its energy into the Day 2 energy markets, consistent with its current cost-based sales tariff, and received a market-clearing price.

155. WEPCO states that, as it explained in its original request for rehearing, the TEMT contemplates that WEPCO will offer its generation into the market. However, WEPCO indicates that it only has market-based rate authority for energy sales outside WUMS, and that its energy sales within WUMS are made pursuant to WEPCO's cost-based sales tariff. Because all sellers of generation in the Day 2 markets will receive the market-clearing price, WEPCO is unsure whether it may bid into the energy markets on a cost basis and receive the market-clearing price for its energy.

156. WEPCO states that it has no immediate plans to seek market-based rates within WUMS. It and its customers have found that the cost-based tariff is a workable platform for its energy sales. Moreover, under the new Day 2 regime, the Midwest ISO market power mitigation rules will be applicable to all Midwest ISO market participants, including WEPCO. Because of the potentially conflicting requirements of the Midwest ISO's market power mitigation rules and WEPCO's cost-based tariff, WEPCO seeks clarification that does not need additional authorization to participate in the energy markets.

157. If the Commission denies this request for clarification, then WEPCO seeks rehearing of the TEMT II Rehearing Order. It states that the Commission's failure to clarify the rules under which WEPCO makes sales in the Day 2 energy markets is unduly discriminatory and subjects WEPCO to burdens and costs that other market participants do not bear. WEPCO states that without the clarification it requested, it must either: (1) risk operating in violation of its cost-based tariff; or (2) apply for market-based rates within WUMS. WEPCO states that either path will result in an undue burden and expense for it, in a manner that is unjust, unreasonable and unduly discriminatory.

158. WEPCO states that it and other market participants are comfortable with the current Commission-approved cost-based sales tariff. Market-based rates always have been optional for utilities, with the burden on the applicant to show a lack of market dominance. WEPCO argues that the Commission has not indicated either that market-based rate authority is no longer optional, or that such authority is required to participate the Midwest ISO's Day 2 energy markets. However, in order to avoid the risk of

violating its cost-based tariff – and undertaking an expensive and time-consuming defense – Wisconsin Electric will be forced to submit an application for market-based rates within WUMS even though it does not wish to do so at this time.

159. WEPCO states that in the future, it may decide to apply for market-based rate authority in WUMS, as the Commission has suggested. However, for the Commission, through its silence, to impose such an obligation on WEPCO is unreasonable and unduly discriminatory. It states that, given the extraordinary level of activity required of it – and all parties in the Midwest ISO region – at this time, it is not prepared to compile a market power analysis, or to assume the burden of demonstrating the justness and reasonableness of market-based rates within WUMS. WEPCO states that if it is forced to make such a filing, the application could be contested and become yet another hurdle that stakeholders in WUMS must overcome before receiving the benefits of the Midwest ISO's energy markets. WEPCO urges the Commission to grant rehearing and determine that it need not seek market-based rate authority within WUMS in order to participate in the energy markets on the same footing as any other market participant.

iii. <u>Discussion</u>

160. As an initial matter, we note that WEPCO filed an application to sell into WUMS under a market-based rate tariff. The Commission approved its filing in an order issued March 22, 2005.[153]

161. The TEMT II Rehearing Order explained the process WEPCO must follow to obtain market-based rate authority, and it chose to take that option. While we believe our earlier ruling on this matter was clear, we provide further clarification to WEPCO, based on its request in this proceeding, that this procedure is the only option for obtaining approval to receive the market-clearing price, and WEPCO can not receive the market-clearing price under its cost-based sales tariff.

162. We also clarify that the only options for WEPCO to participate in the Midwest ISO Day 2 energy market are with Commission approval of a market-based rate application or Commission approval of a cost-based rate application. While the Commission did not spell out the procedure for cost-based rate authorization in the energy market in the TEMT II Rehearing Order, the Commission's silence on this issue

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[153] *Wisconsin Electric Power Company*, 110 FERC ¶ 61,340 (2005).

did not mean that option was foreclosed. WEPCO chose instead to seek market-based rates, which have been approved. We clarify for WEPCO that a market-based application is required for participation in energy markets since WEPCO's cost-of-service tariff is not the rate its generators will be bidding into, or receiving from, the energy market.

163. In either case, whether WEPCO chose to seek market-based rate authority or cost-based rate authority, WEPCO would have to make an application to do so. Therefore, we disagree that the market-based rate authorization process represented a burden to WEPCO, and we disagree that the application requirements for WEPCO are different than other, similarly situated, entities.

H. Seams Issues

1. Implementing the TEMT in the Midwest ISO Footprint

a. Background

164. In the TEMT II Rehearing Order the Commission clarified that the load of the other party, [the other party in the agreement with Otter Tail] is subject to the Midwest ISO charges to the extent it receives transmission service over Otter Tail's facilities controlled by the Midwest ISO.[154]

b. Requests for Rehearing

165. Basin Cooperatives are concerned that certain of the Commission's statements in the TEMT II Rehearing Order could erroneously be interpreted as permitting Otter Tail to pass through charges to them. Basin Cooperatives ask the Commission to clarify that those statements apply solely to whether the Midwest ISO can impose such charges, and not to whether Otter Tail can pass through these charges to East River.

166. Basin Cooperatives state that East River and Otter Tail are parties to the contract the Commission refers to in this proceeding as GFA No. 308, which is carved out of the Midwest ISO energy markets.[155] They note that, in the TEMT II Rehearing Order, the Commission stated that the "load of the other party to the GFA is subject to the Midwest ISO charges to the extent it receives transmission service over Otter Tail's facilities

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[154] *See* TEMT II Rehearing Order at P 542.

[155] Basin Cooperatives Request for Rehearing at 2 (citing GFA Order at P 190).

controlled by the Midwest ISO.[156] Basin Cooperatives assert that this statement could be interpreted to mean that Otter Tail may pass through Midwest ISO charges to East River if East River receives transmission over Otter Tail facilities under GFA No. 308. They argue that this interpretation would be inconsistent with the Commission's prior decisions, since the Commission has determined that such a pass-through would be contrary to its policy.[157]

167. Basin Cooperatives state that clarification would help to reduce the controversy with respect to the administration of carved-out GFAs, since Otter Tail has taken the position that it is not the Responsible Entity, the Scheduling Entity or the market participant with respect to GFA No. 308 and has indicated that it believes that it is not obligated to incur any costs from the Midwest ISO associated with that contract. Basin Cooperatives ask that the Commission clarify that its statement applies only to whether the Midwest ISO can charge these costs, not to whether Otter Tail can pass these costs through to East River. They allege that such a determination would be outside the scope of these proceedings.

168. Otter Tail filed a response to Basin Cooperatives' request for rehearing, urging the Commission to deny Basin Cooperatives' request. Otter Tail states that Basin Cooperatives' request that the Commission proclaim that Otter Tail may not pass through Midwest ISO charges associated with GFA load to East River is premature because Otter Tail has not proposed to pass through any such charges associated with East River's load.

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[156] *Id.* (quoting TEMT II Rehearing Order at P 542).

[157] Basin Cooperatives state that the Commission found in Opinion No. 453 that even if GFA customers benefit from RTO functions, the Commission will not require the pass-through of those charges to the GFA customers. Instead, the Commission held that the rate should be designed based on an allocation of costs to all loads, including loads of customers under GFAs, but it required the transmission-owning members of Midwest ISO who were parties to the GFAs to bear the costs, and it rejected requests to require the GFA customers to bear the costs. Basin Cooperatives Request for Rehearing at 2 (citing *Midwest Independent Transmission System Operator, Inc., et al.*, Opinion No. 453, 97 FERC ¶ 61,033 at 61,169 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002), *order on remand*, 102 FERC ¶ 61,292, *order on reh'g*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom. Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004)).

Otter Tail states that if it were to attempt to pass through such charges, it would make a filing under section 205 of the FPA, and that Basin Cooperatives could challenge such a filing. Otter Tail states that, from a practical perspective, it does not make sense to foreclose the possibility of passing through charges.

169. Second, Otter Tail states that Basin Cooperatives' request that the Commission visit the issue of the appropriateness of a potential tariff provision to pass through charges imposed on GFA loads is out of time. The Commission addressed the possibility of a tariff provision passing through such costs in a rehearing order addressing Schedules 16 and 17. Otter Tail notes that the Commission explained in that proceeding that the "Midwest ISO TOs may make a filing with the Commission that proposes, as PG&E's filing did, to recover Schedule 16 and 17 costs from their customers as new services."[158] The Commission reiterated this statement in the GFA Order, noting that "when the contracts do not allow modification to recover Schedule 16 and 17 charges, another option would be to seek recovery of costs incurred under Schedules 16 and 17 as new services."[159] Otter Tail notes that the Commission also found that the issue was unripe:

> While the Transmission Owners and the Midwest ISO urge the Commission to adopt a tariff mechanism to charge GFA customers directly for Schedule 16 and 17 service, they have not made a concrete proposal identifying the GFA party that should be responsible for such costs or addressing whether or not the contracts already address responsibility for such costs. Thus, the proposal is not ripe for consideration.[160]

Otter Tail concludes that the Commission indicated that it would consider a tariff provision to pass through Schedule 16 and Schedule 17 costs as new services.

[158] *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,337 at P 18 (2004).

[159] GFA Order (citing *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,337 at P 18 (2004)).

[160] GFA Order at P 302.

170. Next, Otter Tail argues that if Basin Cooperatives disputed the pass-through issue, it was required to file a request for rehearing of the Commission's earlier orders within thirty days of the issuance of those orders. Otter Tail states that as Basin Cooperatives are seeking review of an issue later than thirty days after the Commission addressed that issue in an order, their request must be denied as out of time.

171. Finally, Otter Tail argues that Basin Cooperatives wrongly asserts that an interpretation allowing Otter Tail to pass through charges is inconsistent with Commission policy. To the contrary, Otter Tail says, the Commission has recently accepted tariff provisions allowing for the pass-through of scheduling and market operations costs to customers under existing contracts because they are receiving a "new and different service."[161] Basin Cooperatives' reliance in this case on a 2001 order is misplaced, both because the Commission addressed this issue generally in more recent California orders and because the Commission addressed it squarely in an order specifically dealing with this proceeding.

c. Discussion

172. We clarify that the TEMT II Rehearing Order applied solely to whether the Midwest ISO can impose charges and that Otter Tail must obtain authorization in a separate section 205 proceeding to pass through Midwest ISO charges to the Basin Cooperatives for GFA Contract No. 308, and that this authorization is beyond the scope of this proceeding. We note that the Midwest ISO has filed, and the Commission has approved, Schedule 23, which allows for a pass-through of Schedule 10 and 17 charges to the parties to GFAs that are carved out of the energy markets because they are subject to the "just and reasonable" standard of review.[162] The Commission has established hearing and settlement judge procedures to determine what charges may be passed through to GFAs that are subject to the "just and reasonable" standard of review and participating in the Midwest ISO energy markets.[163]

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[161] *See Pacific Gas & Electric Co.*, 107 FERC ¶ 63,030 at P 48 (2004), *aff'd in relevant part*, 109 FERC ¶ 61,093 (2004); *see also California Independent System Operator Corp.*, Opinion No. 463, 103 FERC ¶ 61,114 at P 46 (2003), *order on reh'g*, Opinion No. 463-A, 106 FERC ¶ 61,032 (2004).

[162] *See Transmission Owners of the Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,339 (2005).

[163] *See Otter Tail Power Company*, 110 FERC ¶ 61,220 (2005).

<u>The Commission orders:</u>

(A) The requests for rehearing are hereby granted in part and denied in part, as described in the body of this order.

(B) The Midwest ISO's January 7, 2005 compliance filing is hereby accepted, subject to revision and further order, as described in the body of this order. The IMM's safety-net mitigation plan is hereby accepted, and the Midwest ISO is required to implement it, effective April 1, 2005.

(C) The Midwest ISO is hereby required to make compliance filings and informational filings, as described in the body of this order.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary